Final Report
Baseline Distribution Grid Assessment of Ameren IL

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

Presented to:
The Illinois Commerce Commission

Presented by:
The Liberty Consulting Group

April 12, 2022

1451 Quentin Rd Suite 400
#343
Lebanon, PA 17042

admin@libertyconsultinggroup.com

Table of Contents

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 AIC 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 AIC 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 AIC 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 AIC 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 AIC'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 AIC 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 AIC, 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 they reach out to the full population of end users. AIC's system classifies as transmission voltages from 138kV to 345kV. AIC's substations transform a higher transmission voltage to a lower transmission voltage or to distribution voltage levels at 69kV or less, which AIC classifies as distribution. 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, 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 comprise 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 do 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, AIC uses the term "sub-transmission" to describe the components linking higher voltage transmission with lower voltage distribution facilities. It delivers electric service to a small number of very high-use customers at transmission and sub-transmission voltages and serves its remaining customers at "primary distribution voltages" at 15kV and below.

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. The "downstream" numbers of grid components increase. Assessing exposure takes consideration of all the factors that create risk. For example, AIC's electric grid, by most measures, has proportionally greater exposure to weather, animals, vegetation, and public vehicles than does ComEd's electric grid due to greater use of overhead facilities, which affords less protection from environmental elements, as well as a higher percentage of rural overhead circuits.

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 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 one - - 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 (DER) systems.

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 situation 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 remote monitoring of three functions to the centralized system operator: equipment control, metering, and status (alarms), permitting situational awareness at the substation. SCADA permits fast acting preventive and corrective control actions (often on an automated basis) that recognize adverse configurations, adjust 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, 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 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 them 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 the state of the art. Technological advances more recently 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 in locating faults, clearing them, and restoring 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 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. Monitoring of Circuit Laterals through Smart Devices

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 electromagnetic 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, *Distribution 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 AIC's distribution system has undergone a number of developments since 2012, This Chapter describes them. Chapter V, *Capital Investment and O&M Spending*, addresses the costs of capital and O&M programs, projects, and initiatives, and Chapter VII, *Distribution System Performance*, 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. For purposes of this Chapter, major sources of configuration change include those described below, which exemplify the kinds of programs, projects, and initiatives commonly undertaken in the industry and which have contributed to the system performance improvements detailed in Chapter VII.

- As have most utilities, particularly those serving those with stable customer numbers and steady to declining peak loads, AIC dedicated the bulk of its distribution system capital expenditures to replacing aging, deteriorated, and obsolete equipment, and most of its asset management expenditures on maintaining existing equipment and the corridors it traverses and sites it occupies. These expenditures did not materially change the configuration, but instead kept facilities in a condition to operate soundly.
- AIC's distribution system remains primarily rural, with some urban and suburban areas in each of its regions.
- The base electrical needs served by AIC since 2012 have remained stable, with annual peak load decreasing by a very substantial 15 percent, and customer numbers increasing by one percent. New customer connections have required expenditures, but additions of new substations and lines (a significant source of expenditure for utilities with faster growing loads) has remained moderate. Nevertheless, uneven growth in some areas has led to some expenditures for new resources to serve pockets of growth.
- Total miles of distribution circuits changed little, increasing slightly by about two percent. The distribution system primarily (approximately 85 percent) employed overhead facilities, whose circuit mileage increased by about 1.3 percent, while underground cable circuit mileage increased by eight percent.
- Legacy underground cable problems have occurred throughout the industry; AIC faced them as well, making continuing expenditures to replace poorly performing underground cables. AIC accelerated their replacement (~8 percent circuit miles) during the study period.
- AIC materially enhanced system capabilities, particularly focusing on reliability improvements and operability enhancement, which contributed to operating flexibility, economy, and reliability improvement. For example, expenditures of about $85million were directed toward incorporating "smart" operating capability to its system through the addition of reclosers, line sensors, upgraded relays, and device communications. Bringing distribution automation devices and "smart" operating capabilities to about 20 percent of circuits has reduced the number of customers exposed to power outages.

- The number and amount of interconnected Distribution Energy Resources (DER) facilities remain small, reaching about three percent (238MW) of system load by year end 2021, as compared with less than one percent in 2012.
- AIC continued investing in auto-response capabilities with automatic circuit reconfiguration, making about 20 percent of distribution circuits as of 2020 capable of automatically transferring loads upon the occurrence of a contingency threatening or producing service disruptions.
- Circuits serving critical customers, including rural cooperative or municipal systems, employ automatic throw-over switches served by two or more circuits or dedicated customer substations.
- Secondary networks, used to serve customers in dense urban areas, include multiple supply sources and transformers, which provide for uninterrupted service when one or two primary voltage sources or transformers remain out of service.
- System remote monitoring capability at substations via SCADA (Supervisory Control and Data Acquisition) increased to approximately 50 percent, allowing system operators to monitor operating conditions and to control substation equipment and circuit breakers remotely. AIC also included SCADA communications capability with many of its recently installed upgraded circuit reclosers (smart switches).
- AIC made significant additions of reclosing devices, with many able to communicate with each other, on lateral tap circuits branching from mainlines, serving to reduce service interruptions. In addition, auto-response capability grew, through use of single-phase operation reclosers on main stem devices, providing further customer impact reduction to approximately 76 percent of AIC's system total distribution circuit miles.
- Modernization of protective relays at about half of substations has also helped to reduce equipment damage, automatically locate circuit faults, and reduce customer outages.
- AIC upgraded overcurrent protection to 1 percent of the distribution circuit laterals with the installation of "smart fuses" and replaced one-use-and-done fuses with automatic reclosing devices. This investment effort is likely to continue, given the lateral circuit exposure on the system.

B. Company Description

1. Overview

AIC's geographic footprint stretches across the lower 75 percent of the state, covering approximately 43,700 square miles of service territory, in which it serves 1.2 million electricity customers in five of the state's twenty largest cities and over 1,200 mostly rural communities. It provides electric service from a delivery system that includes about 4,500 miles of electric transmission lines and 47,000 miles of distribution lines. AIC also serves approximately 24 co-operatives and 50 municipal electric system providers that serve more than 500,000 customers. AIC had about 3,200 employees in 2020.

The holdings of Fortune 500 company Ameren Corporation (AEE, also its New York Stock Exchange symbol) include AIC, based in Collinsville, Illinois. AEE also owns Ameren Transmission Company, under which the holding company has aggregated its transmission businesses, which include Ameren Transmission Company of Illinois (ATXI). AIC resulted from a combination of three Illinois utilities (CIPSCO Incorporated, CILCO Inc., and Illinois Power Company) and the holdings of Union Electric Company of St. Louis, Missouri.

AIC divides its electric service territory into the four regions (North, South, East, West) as depicted in the following figure. The irregular regional boundaries somewhat follow the service areas of the legacy companies. Communities served and geography give each region unique characteristics, but they employ comparable delivery system assets, with the numbers of urban concentrations in each a principal driver of system differences.

AIC's Service Territory and Regions

Overall, AIC operates a largely rural, overhead construction electric delivery system with significant lateral exposure per circuit. Thus, a single-phase overhead configuration makes up most of its distribution circuit miles. Underground distribution circuit miles as a percentage of total miles increased marginally from 15 percent (~6,900 miles) to 16 percent (~7,500 miles) from 2012 through 2020. AIC's average distribution circuit customer density of between 19-22 customers/mile makes it representative of rural U.S. delivery systems. With Illinois more than 70 thousand farms averaging over half a square mile in size, it is reasonable to describe an "average AIC distribution circuit" as a mix of in-town and single farm services.

Thirty-five percent of AIC's overhead sub-transmission circuit miles and 25 percent of its distribution circuit miles, 2,432 circuit miles 8,055 circuit miles, respectively, require vegetation management. The balance of the overhead system (a substantial portion of it farmland) does not routinely require clearing, trimming, or treatment.

2. *North Region*

The North Region contains a concentration of the largest cities that AIC serves; those cities include Springfield metro (Springfield has a municipal system), Peoria, Bloomington, Decatur, Normal, Pekin, and Galesburg. The North Region has 8 percent more distribution circuits than the average of the other three regions. It contains the most distribution circuit miles and the most overhead circuit miles, almost double some of the other regions. The North region's vegetation management requirements exceed the average of the other regions by about one third.

North Regions serving four of the top five largest city metro areas contain network transformers and protectors (*i.e.*, vaults below city streets) absent in the other regions. This infrastructure typifies older, urban underground (UG) systems. The region has the largest population of underground construction distribution circuits, its UG transformer numbers more than double those of the other regions. It also has more than double the Underground Residential Development (URD) construction, more typical of newer suburban development. The North Region has led the other regions for the last eight years in adding UG distribution circuit miles.

3. *South and Western Regions*

The South and West regions share the Mississippi River as a western border and split the Illinois portion of St. Louis's suburban areas. Both regions contain hilly ground approaching major river valleys and riparian areas, their terrain imposing greater vegetation management needs. The South region contains significant National Forest land and the Ohio River valley terrain. Both regions contain a mix of rural and urban service areas.

4. *East Region*

The East region contains the least number of circuits and the lowest geographic density of facilities. The region contains one more distribution field operations area than do the other three. The mostly rural region does, however, serve Champaign-Urbana, a university-city with a 10 percent population growth since 2010. Serving this area primarily drove the addition of 50 miles of URD circuit miles in 2020. Eighty-eight percent of the region's sub-transmission line voltage operates at 69kv, effectively serving as a transmission system.

5. *Customer Growth*

The next table summarizes the changing composition of AIC electric service customers and annual Peak Loads in megawatts from 2012 to 2020. AIC's customer base grew about one percent during this period, with industrial customers declining by five percent. Peak load declined 15 percent.

Customers (000) and System Peak

		2012	2013	2014	2015	2016	2017	2018	2019	2020
Customers	*Residential*	1,055	1,062	1,062	1,060	1,062	1,059	1,058	1,059	1,060
	Commercial	146	148	150	150	150	150	151	152	153
	Industrial	9.3	9.4	9.4	9.2	9.2	9.1	9	8.9	8.8
Peak Load (MW)		7,851	7,235	7,259	6,973	7,138	7,145	7,052	7,032	6,644

AIC's total customer base has remained essentially flat, with distribution circuit miles increasing by about two percent since 2012. Illinois has experienced declining population overall, but communities, home to public sector industries such as education and government, have experienced growth. Springfield, the state capital, as well as university communities such as Champaign, Bloomington-Normal, and Edwardsville all saw growth, while many traditional industrial cities experienced decline. This trend has required AIC electric system planners to respond to localized areas of growth and decline. AIC distribution system growth follows capacity growth, customer requests, and customer mobility. Utilities generally do not retire delivery assets in regions of demand and usage decline, often producing lower utilization of them as a percentage of their capabilities. The next table summarizes AIC's customer base.

2020 Customer Base

Customer Type	**Region**				**System Total**
	North	**West**	**South**	**East**	
Residential	371,060	239,419	228,746	221,047	1,060,272
Commercial	52,471	33,984	32,807	34,545	153,807
Industrial	2,335	2,299	2,393	1,798	8,825
Total	**425,866**	**275,702**	**263,946**	**257,390**	**1,222,904**
Urban, Suburban, Rural Areas	**Region**				**System Total**
	North	**West**	**South**	**East**	
Urban	92,040	42,133	22,368	54,492	211,033
Suburban	121,322	95,905	102,486	88,043	407,756
Rural	205,672	135,546	138,478	112,907	592,603

Note that the area numbers (urban, suburban, and rural) include only 15kV and below customers on a distribution circuit for which AIC can calculate this classification. Therefore, they represent a subset of the Customer Type numbers.

C. Distribution System Configuration

The AIC transmission system links power generating facilities with the delivery system. Transmission facilities generally provide the source to sub-transmission assets and frequently to new distribution substations. AIC's 221 transmission lines in 2020 spanned about 4,500 miles. Transmission assets offer the highest power transfer capability among delivery subsystems. Higher voltages can transmit power further distances with reduced power loss. Electric utilities generally configure transmission lines in a network or "meshed" configuration. The two or more terminals available permit bi-directional (network) flow. SCADA provides the primary means for monitoring transmission line operation at substation endpoints.

The following section summarizes the regional characteristics of AIC's distribution delivery system. It describes functions, quantities, penetrations, redundancy, monitoring capability, and automation as applicable for the various sub-systems addressed.

1. Sub-Transmission Substations

AIC sub-transmission substations (where the lowest circuit exit voltage exceeds 15kV) typically have a role in serving more customers than do distribution substations, with their lower exit voltages. They are thus also fewer in number while serving across a much larger geographic footprint when compared to distribution substations. As proves true of the industry, AIC provides greater redundancy for sub-transmission substations by providing them much more frequently with multiple sources. Sub-transmission substation multiple sourcing is accomplished on AIC's system by use of networked sub-transmission lines and remotely controlled line reclosers, or automated sub-transmission lines, and remotely controlled line reclosing switches. SCADA provides remote monitoring and operability, augmented by communicable relaying. Notably, AIC has provided SCADA monitoring at all its sub-transmission substations. The following table summarizes sub-transmission substation characteristics as of 2020.

Sub-Transmission Substation Characteristics

Subsystem		Region				AIC System
Asset Type	**Attribute**	**North**	**West**	**South**	**East**	
Sub-transmission	Number of	17	13	10	14	54
69kv or 34kv is Lowest Exit Voltage	% Monitored SCADA	100%	100%	100%	100%	100%
	Communicable Relaying	31%	24%	27%	29%	29%

2. Sub-Transmission Circuits

The network configuration AIC has generally applied to sub-transmission circuits produces high levels of redundancy to address exposure to conditions and events that threaten service disruptions. Circuit sectionalizing and automation schemes augment auto-response characteristics for these circuits. SCADA (at substations) provides high levels of remote circuit monitoring and operability, augmented by communicable relaying at the substations. Circuit configuration relies on three-phase operation. AIC has much lower exposure on its underground (UG) sub-transmission circuits, much smaller in number and mileage, given their concentration in a relatively small urban component of the service territory. AIC reports high levels of redundancy and automation on 99 percent of sub-transmission circuits. Thus, the ability to conduct automatic switching to isolate faults and prevent service interruptions has become essentially ubiquitous on these circuits. The next table summarizes sub-transmission circuit characteristics as of 2020.

Sub-Transmission Circuit Characteristics

Subsystem Asset Type	Subsystem Attribute	Region				AIC System
		North	West	South	East	
Sub-Transmission Lines (69 & 34kv) > 15KV	Number	169	158	131	117	575
	Exposure Overhead Circuit Miles	1,579	2,001	1,559	1,661	6,800
	Exposure UG Circuit Miles	0	27	0	0	27
	Avg Mi./Line	9.3	12.6	11.9	14.2	12
	Redundancy % Networked	67%	91%	76%	80%	78%
	% Lines with Automation	No data	No data	No Data	No Data	99%
	Direct Connect Customers	480	277	176	202	1135

3. *Distribution Substations*

The next link in the distribution chain consists of distribution substations, which employ circuit exit voltages of less than 15kV. AIC generally employs redundancy to limit exposure to customer interruptions affecting distribution substations. SCADA provides many of these substations with remote monitoring and operability, augmented by communicable relaying at a large percentage of them. The next table summarizes distribution substation characteristics. During the study period AIC increased the percentage of SCADA monitored distribution substations from 48 to 78 percent. The addition of microprocessor-based relaying (MPR) during the study period brought the total number so enabled to 29 percent of total system relays.

Distribution Substation Characteristics

Subsystem Asset Type	Subsystem Attribute	Region				AIC System
		North	West	South	East	
Distribution Substations (Lowest Exit Voltage ≤ 15kv)	Number	257	255	237	217	966
	% Multi-Sourced	52%	78%	72%	77%	70%
	% Monitored SCADA	-	-	-	-	78%
	Communicable Relays	31%	24%	27%	29%	29%

4. *Distribution Circuits*

AIC Distribution circuits (*i.e.*, circuit voltages less than or equal to 15kV), involve large numbers of sub-components and overhead circuit miles (85 percent of total circuit miles). AIC employs a lower level of redundancy in its distribution (versus sub-transmission) circuits, a very large number of them in radial rather than networked configuration. AIC does, however, make extensive use of manual circuit ties (on about 95 percent of the circuits involved), circuit sectionalizing (on about 75 percent), and automation schemes (on about 20 percent). SCADA at distribution substations provides remote monitoring and operability at about 50 percent of these circuits, augmented by communicable relaying at the substations, involving about 10 percent of the circuits. AIC employs three-phase configurations for these overhead circuits. The following table summarizes distribution circuit characteristics.

Distribution Circuit Characteristics

Subsystem Asset Type	Subsystem Attribute	Region				AIC System
		North	West	South	East	
Distribution Circuits (≤ 15kv)	Number	678	649	599	575	2501
	Overhead Circuit Miles	12,267	7,239	5,376	6,182	32,388
	Underground Circuit Miles	3,087	1,329	1,597	1,276	7,290
	Avg. Miles/Circuit Overhead Underground	18 4.5	11 2.6	11 2.7	10,8 2.2	13 2.9
	No. of Poles (AIC owned)	218,267	114,504	147,934	76,389	557,094
	% Manual Tie	99%	93%	97%	94%	95%
	% Circuit >1 Mid-Point Recloser	67%	80%	74%	83%	76%
	% Lines with Automation	28%	13%	21%	20%	20%

AIC employs lateral (single or dual phase construction) configuration on approximately 75 percent of distribution circuits, protecting them primarily with fuse devices. AIC employs an average of thirty laterals per circuit, but lateral smart fuses comprise less than one percent of the lateral protection devices. The following table summarizes lateral distribution circuit characteristics.

Lateral Distribution Circuit Characteristics

Distribution Circuit Laterals (Branches from Main-stem of Distribution Circuits) (≤ 15kv)	Number	26,342	15,548	18,132	14,472	74,494
	Exposure OH Circuit Miles	10,897	5,222	5,376	4,151	25,648
	Exposure UG Circuit Miles	2,318	1,044	1,251	920	5,532
	Avg. Mi/Lateral OH (1, 2 PH) UG	16 3.4	8 1.6	8 2.1	7.2 1.6	10.1 2.2
	% w/ Smart Fuse	0.7%	0.5%	0.6%	0.7%	0.7%
	Direct Connect Customers	419,034	273,584	263,332	255,442	1,211,392

5. *Distribution Transformers and Customer Metering*

AIC operates a vast number of distribution transformers and customer meters. Their large numbers increase failure numbers, but those individual failures have too low a resulting impact to justify redundancy. Distribution transformers possess low monitoring capability, but the high remote monitoring capability of AMI meters, now installed for more than 99 percent of AIC customers, compensate for that lack.

Distribution Transformer and AMI Characteristics

Subsystem Asset Type	Subsystem Attribute	Region				AIC System
		North	West	South	East	
Distribution Transformers	Total	130,970	79,960	93,067	68,114	467,000
	Overhead	87,859	63,870	72,094	52,241	276,000
	Underground & Pad Mount	43,073	16,870	20,973	15,873	96,000
	Network Transformers	77	0	0	0	77
AMI Meters						
AMI Metering	Customers w/AMI	425,867	275,492	263,947	257,163	1,221,478
	% Customers	99.9%	99.9%	99.9%	99.9%	99.9%

V. Capital Investment and O&M Spending

A. Summary

The following table provides an overview of expenditures over the study period, which shows annual spend (*i.e.,* CapEx and O&M) nearly doubling from 2012 to 2020 and total Infrastructure Investment Plan (IIP) spend comprising approximately 20 percent of total capital expenditures over that period.

Capital and O&M Distribution System Expenditures

	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
CapEx Non-IIP	$238	$321	$297	$378	$354	$367	$415	$473	$564	$3,407
CapEx IIP	$26	$33	$89	$128	$106	$126	$83	$67	$41	$700
O&M	$192	$207	$222	$237	$246	$235	$247	$246	$252	$2,084
Total	**$456**	**$562**	**$608**	**$743**	**$706**	**$728**	**$746**	**$786**	**$857**	**$6,191**

The bulk of AIC's expenditures concerned overhead circuits, typical of utilities lacking substantial growth and operating in more rural areas. Non-IIP capital expenditures increased on average 3.7 percent per year. Main drivers of the increase included distribution circuit expenditures, capitalized software investments, distribution substations, and other general plant. Overall, O&M expenditures increased 3.2 percent on average per year (not adjusted for inflation), with overhead circuit and substation expenses the main drivers.

AIC's system experienced a 2 percent circuit mile increase and a 1 percent customer base growth during 2012-2020. Distribution plant in service increased in value by 4 percent per year (in 1998 dollars), with investments in asset replacement, system reliability, and system expansion initiatives.

Principal changes from AIC's total investments came in the form of auto-response capability improvements, which included:

- Circuit automation on sub-transmission and distribution circuits (covering, for example, 20 percent of distribution circuits by year end 2020)
- Additional midpoint reclosers with single phase capability (on 76 percent of the system by year end 2020)
- "Smart fusing" of circuit laterals (reaching 1 percent of the system by year end 2020).

These investments provide a repeating benefit to existing exposure impacts by reducing the number of customers likely interrupted during future interruption events.

In addition, improvements to redundancy of configurations include the following:

- Additional substation transformers, and transformer low side breaker additions (IIP related investment of $29 million)
- Source circuit and transformer high side breaker additions (IIP related investment of $64 million)
- Circuit manual tie additions (approaching 100 percent of system distribution circuits within the study period).

These investments provide redundant paths for single element failures, or rapid restoration via switching to alternate sources to reduce the duration of customer interruptions.

Investments in remote monitoring included SCADA additions, communicable circuit and substation devices, and voltage optimization. These investments increase operations' situational awareness to mitigate and reduce interruption durations. Investments in replacement of assets and advances in materials and technology included gas insulated breaker replacement of oil circuit breakers, electro-mechanical relay replacement with microprocessor-based relays, and composite reinforced poles. These investments provide additional benefits of less maintenance and greater storm resiliency.

Investments targeting more difficult delivery performance areas included customer targeted programs for worst performing circuits and multiple device interruptions, intended to improve reliability for specific target groups where performance is worse than average.

O&M expenditures during the study period increased by 32 percent. These were primarily driven by increased expenditures for overhead circuit maintenance (a 45 percent increase), substation maintenance (a 47 percent increase), and underground circuit maintenance (a 47 percent increase). O&M practice improvements may well have contributed to increased costs by changes noted in later sections of this report, such as changes in maintenance program guidelines, for example, performing pole groundline treatment rather than simply inspection, replacement of cable sections upon first fault over the former three-failure practice, and vegetation management circuit patrols based upon tree-related interruptions of more than one hundred customers, or by guideline triggers for condition-based replacement.

B. Introduction

This Chapter examines AIC's total delivery system expenditures, both capital and O&M. The requirement to serve, though, does not imply that associated expenditures were reasonable in amount or effectively applied, only that some level of funding was necessary to meet that requirement. We make no conclusion as to the efficacy of AIC expenditures. However, capital spending can be, at times, a leading indicator of where strategic investments are deemed useful to improve reliability and resiliency or, at other times, a lagging indicator of where the system failed; *e.g.,* storm restoration. The balance of this Chapter addresses the following topics:

- System Reliability Capital Investment
- Delivery System Capital Investment
- O&M Expenditures
- IIP-Related Capital Investment.

C. System Reliability Capital Investment

Capital spending is at times non-discretionary, as electric utilities must respond to, for example, new customer connections or highway relocation. Spending to improve or replace existing systems, *e.g.*, reliability investment, conversion projects, monitoring or automation projects, and IT systems to improve operational capability, exemplify expenditure categories considered more discretionary in terms of pace and magnitude, albeit still driven by internal goals and stakeholder expectations.

In any event, most system improvements, whether directly intended to improve reliability, contain some reliability benefit. Even reconductoring a portion of a distribution circuit in a highway relocation project likely will improve service, given newer construction standards, advances in materials, and replacement of aged equipment. AIC targeted system reliability and resiliency programs to achieve better subsystem reliability performance. It conducted several programs targeting specific subsystems and construction classes to remedy known performance issues, or to achieve performance improvement.

The following table summarizes capital expenditures for AIC's system reliability initiatives, tracked at the system and regional levels. Each Region maintains its own Reliability Action Plan tailored to the need it faced.

Reliability Programs and Initiatives

Reliability Improvement Programs[1]	Investment Type[2]	IIP Contribution Yes/No	Improvement Strategy[3]
Sub-Transmission Line Hardening	CapEx	Yes	Condition/Exposure
Sub-Transmission Circuit Automation	CapEx	Yes	Auto Response
Substation Animal Outage Reduction	CapEx	Yes	Condition/EH Exposure
Distribution Circuit Animal Outage Reduction	CapEx	No	Condition/EH Exposure
Circuit Repairs/Pole Replacement &	CapEx	Yes	Condition/Exposure
C-Truss Replacement Pole		Yes	
Circuit Device Inspection/Repair	CapEx	No	Condition/Exposure
Circuit Lightning Protection Annual Review	CapEx	No	Condition/EH Exposure
Circuit Multiple Device Interruption (MDI)	CapEx	No	Condition/Exposure
(basis >3 interruptions/device/year)			
Circuit Underground Primary Cable (basis <30day post interruption Repair)	CapEx	Yes	Condition/Exposure
URD Circuit Cable Replacement-1st Fail			
Distribution Circuit Automation	CapEx	Yes	Auto Response
Worst Performing Circuits (WPC) (ICC requirement)	CapEx	No	Condition/Exposure
Circuit Hendrix Cable Replacement	CapEx	Yes	Condition/Exposure

Circuit Improvement (basis: interruptions >1000 CI)	CapEx	No	Condition/Exposure
Circuit Manhole Inspection (10-year cycle)	CapEx	Yes	Condition/Exposure
Circuit Mid Circuit Reclosers Additions	CapEx	No	Auto Response
Circuit Lateral fusing "Trip Saver" replacement	CapEx	No	Auto Response
Distribution Transformer CSP Conversions	CapEx	No	Condition/Exposure
Customers with Repetitive Outages (CROP) > 3/year	CapEx	No	Condition/Exposure
Customers Exceeding Reliability Targets (CERTS) [ICC requirement]	CapEx	Yes	Condition/Exposure

[1] Color coded for Subsystems (Blue = sub-transmission; Green = Substations; Yellow = Distribution; Pink = Customer Basis)
[2] CapEx includes both IIP and Non-IIP investments, as noted
[3] Includes reduction of exposure to specific environmental hazards (EH), or for general asset condition, such as age, or deterioration

The table highlights distribution and sub-transmission circuit subsystems (green shading) as the areas of principal focus. Substations did not involve a large number of programs and initiatives, but AIC did devote significant resources to them in the form of inspection and maintenance routines intended for their performance. (See Chapter VI, *Distribution System Condition*.)

D. Delivery System Investment

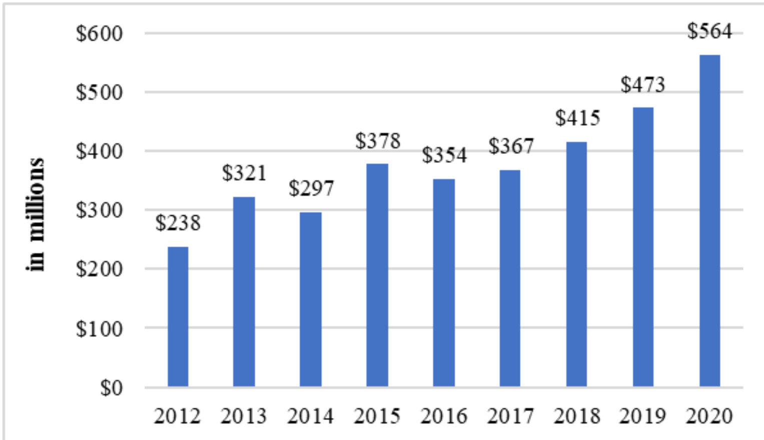
AIC reports electric system investment and the growth in delivery system assets (Plant In Service) via annual ICC reliability filings. The following table shows investment in 1998 dollars, consistent with Part 411 reporting requirements and bifurcated by transmission and distribution accounts. AIC made substantial increases in investments and plant in service inventory between 2012 and 2020. The totals shown exclude IIP investments during the period. Note that one cannot necessarily compare Annual Reliability Report data with other distribution construction and maintenance information in this Liberty report. Not all the data herein uses the same calculation or categorization basis.

Transmission and Distribution Delivery System Expenditures

	Transmission		Distribution	
	Plant In Service	Construction & Maintenance	Plant In Service	Construction & Maintenance
2012	$749	$105	$3,544	$315
2020	$2,413	$444	$4,714	$543
Avg %/ Year	25%	36%	4%	8%

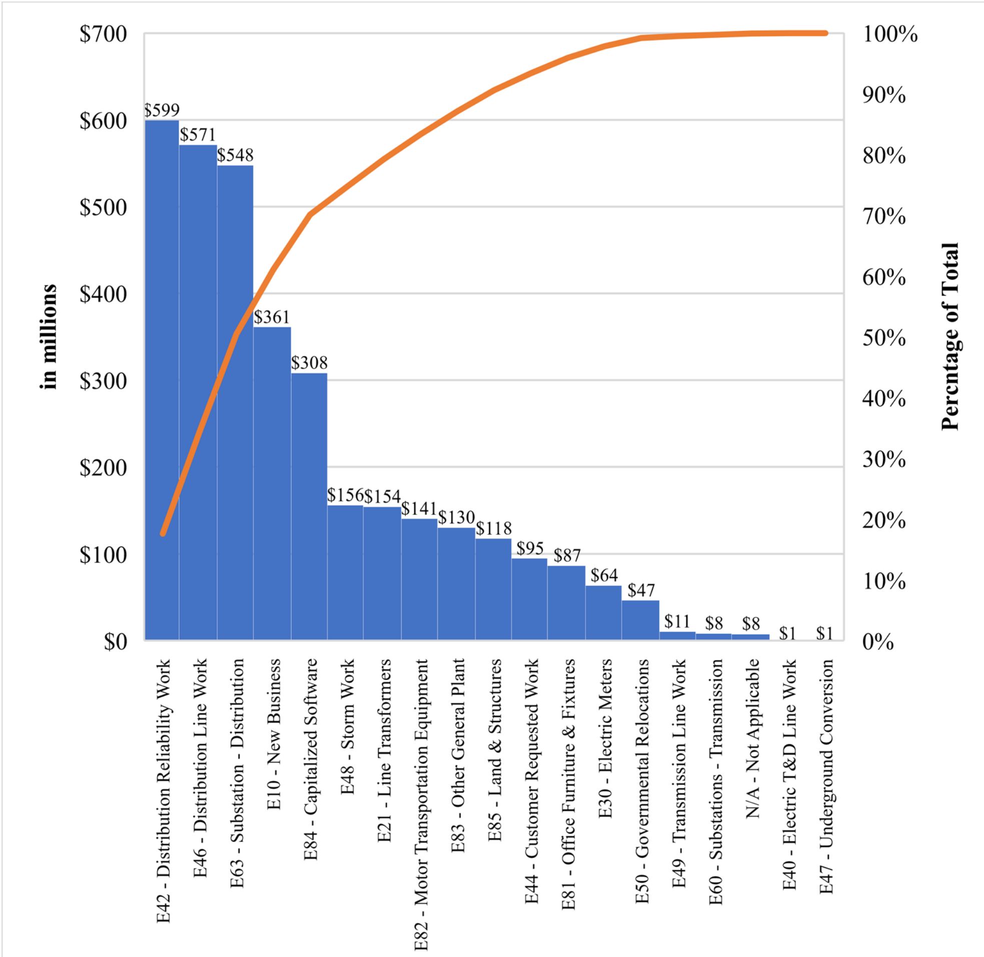
The next chart shows that capital expenditures (excluding IIP capital amounts) increased annually in nominal dollars (from Part 411 reporting using 1998 dollars).

Annual Total CapEx Dollars



AIC uses two-tiered tracking of financial expenditures, applying Budget Group and Reason Codes. This data does not use Part 411 reporting conventions (*e.g.*, use of 1998 dollars). Budget Group codes align with asset classes and include some non-asset-based codes (akin to customary financial categories; *e.g.*, New Business, Capitalized Software). Reason Codes provide an underlying reason, trigger, or motivation for the expenditure, loosely aligned with a range of stakeholder needs for investment in, or modification to, the electric delivery system. The following graph depicts total capital expenditures by reported Budget Group code (again excluding IIP) over the period 2012 - 2020.

Capital Expenditures by Budget Group



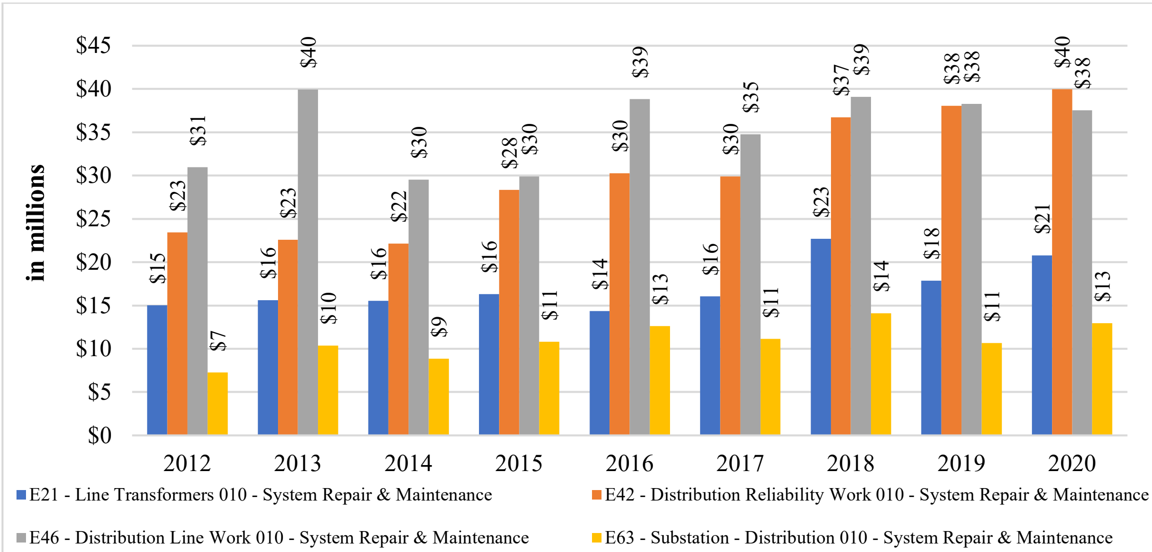
Distribution Reliability Work, the largest category, accounted for over 47 percent of capital expenditures during the period. Investments in reinforcement and replacement of assets and subsystems identified in the system delivery model account for over a third of expenditures. Capitalized software, invested to increase system capability and operations via information technology, accounted for 9 percent of investment.

New business, Customer Requested Work, Government Relocations, expenditures responsive to stakeholder input, accounted for nearly 15 percent of total investment. Many of these investments also produce system reliability improvement.

In aggregate, the top eight budget group categories accounted for over 75 percent of total investment during the 2012-2020 period. Electric Meters accounted for nearly 2 percent, excluding IIP AMI-related expenditures.

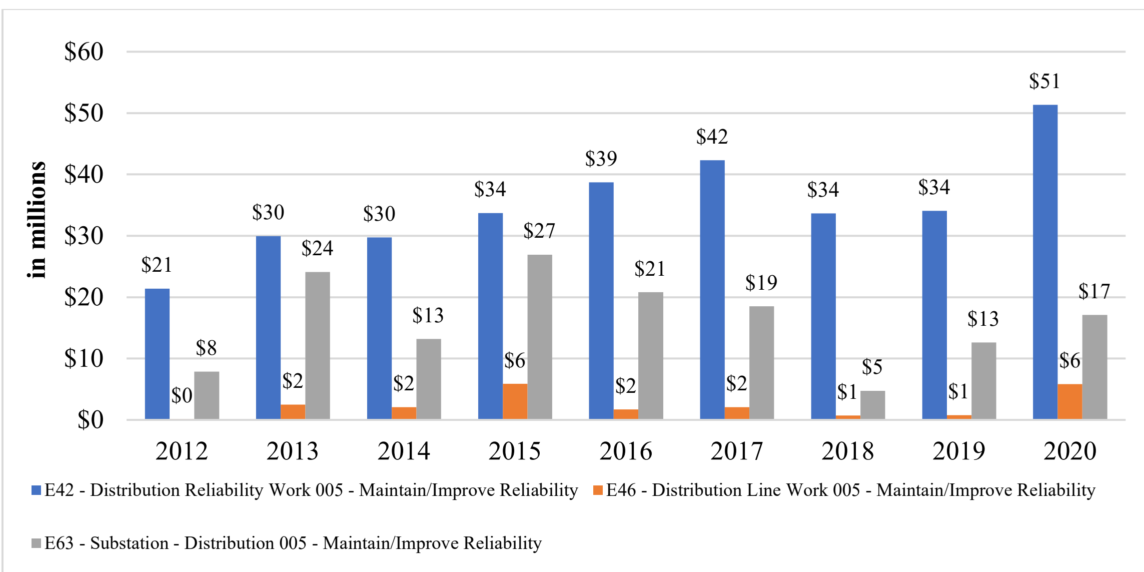
AIC capitalizes asset replacement, both planned and unplanned, making Reason Codes useful management tools to assess expenditure trends and drivers, as the following graphs illustrate. The first chart displays System Repair and Maintenance capital expenditures for selected Budget Groups (excluding IIP), illustrating unplanned asset replacement driven by asset condition. The selected groups align with the relative rank of subsystem exposure, *e.g.*, distribution line work, maintenance, and reliability are the highest for circuits due to the physical miles of circuit components and the number of components in circuits compared to distribution substations.

System Repair & Maintenance Capital Expenditures by Budget Group



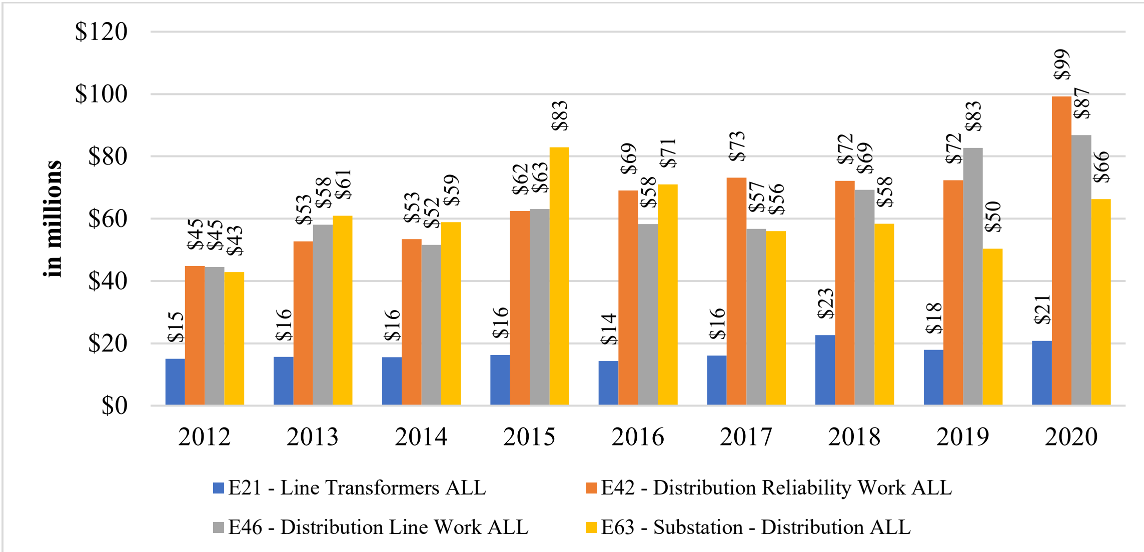
The next chart displays the Maintain/Improve Reliability Reason Code capital expenditures for selected Budget Groups (excluding IIP), illustrating relative expenditure levels for planned asset replacement reliability initiatives.

Maintain/Improve Reliability Capital Expenditures by Budget Group



The following chart summarizes by budget groups the capital expenditures for all Reason Codes.

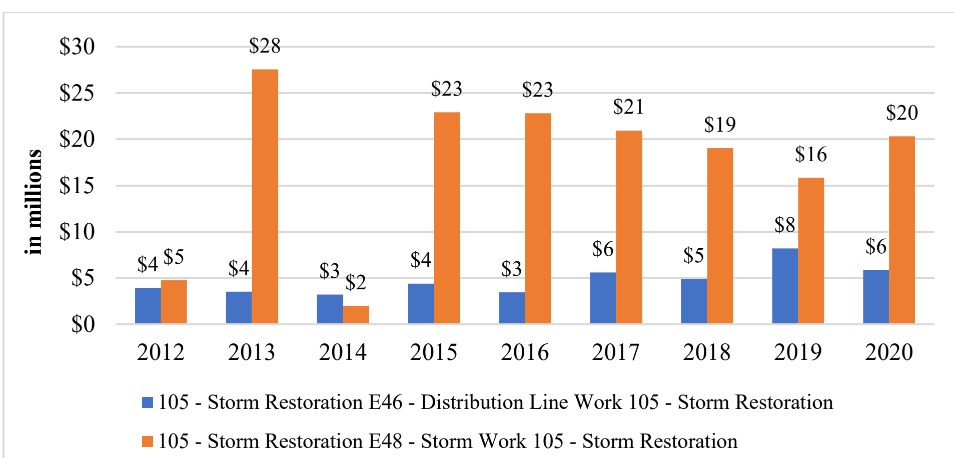
Capital Expenditures Budget Group Totals



The preceding charts show that reliability expenditures over the period more than doubled for distribution circuit systems as did distribution line work. Distribution substation expenditures increased by approximately half, and distribution transformers remained steady, all consistent with identified maintenance strategies. The trends also appear consistent with the relative extent of subsystems, and with increasing scope over time of the reliability initiatives detailed in Chapter VII, *Distribution System Performance*, as well as with the maintenance routines described in Chapter VI, *Distribution System Condition*.

As discussed in Chapter VII, *Distribution System Performance*, severe weather conditions affect electric delivery system operation. AIC takes a two-tiered approach to severe-weather financial tracking. A Storm Work Budget Group and a Storm Restoration Reason Code provide financial detail regarding severe weather impacts. The following chart depicts all Storm Restoration capital expenditures (regardless of Budget Group) for 2012-2020. Distribution Line Work, as opposed to distribution and transmission substations, was the primary source of costs due to severe weather.

Storm Restoration Annual Total 2012-2020



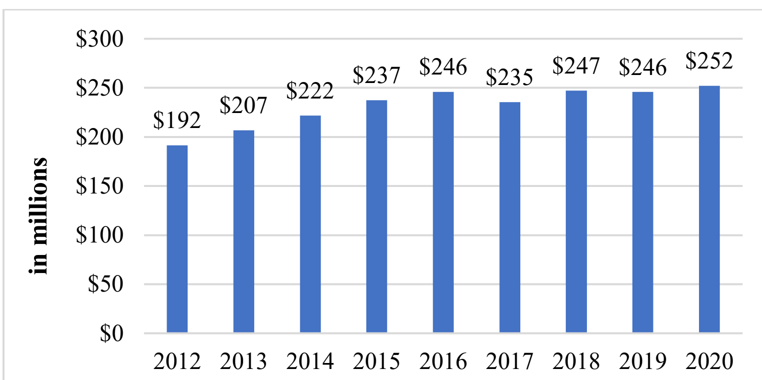
E. Operating and Maintenance Expenditures

Operating and Maintenance expenditures provide another input measure of AIC's system management. System monitoring, IT enhancements, and automation can reduce the dependence on traditional boots-on-the-ground methods of legacy systems and staffing. In addition, equipment technology improvements have also led to more reliable and less maintenance intensive assets, *e.g.*, microprocessor-based relays, solid dielectric fault interrupting devices, gas insulated breakers, integrated onboard diagnostics, transformer integrated dielectric health systems, etc. These advances permit less frequent inspection and less invasive maintenance practices, in part due to fewer moving parts, but also due to automatic detection and monitoring of incipient failure conditions. Monitoring and automation also permit the reduction of operating personnel truck rolls due to remote control operation and knowledge of status and operating conditions.

As a result, decreasing O&M expenditures do not necessarily reflect inattention and can signal efficiencies or maintenance efficacy. Trends in maintenance completion and inspection and maintenance back-logs also warrant consideration in reviewing O&M expenditures (see Chapter VI, *Distribution System Condition*).

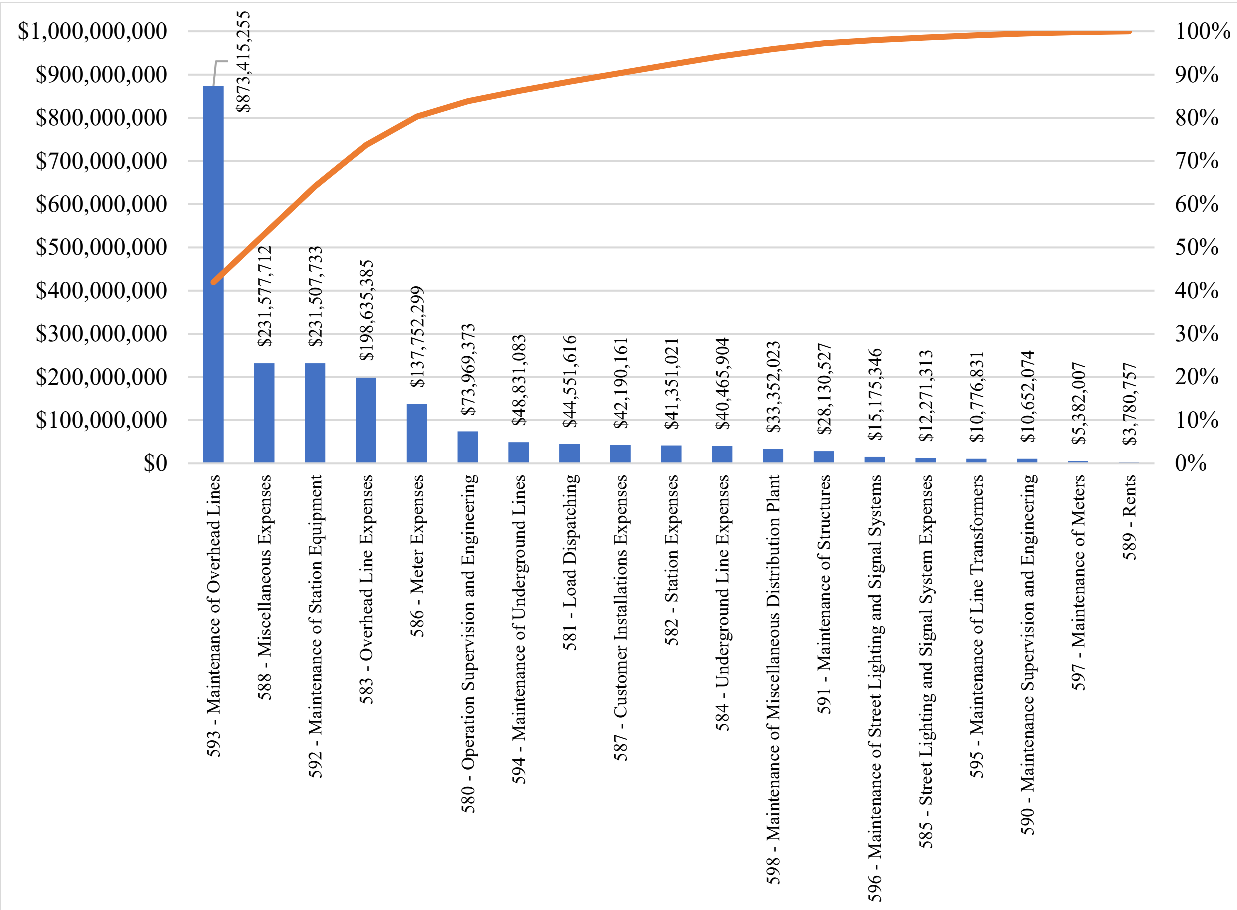
The following exhibit shows AIC's O&M expenditures from 2012-2020. O&M expenditures increased about 25 percent in the first four years, then remained essentially flat for the ensuing four. The number of AIC employees increased from 2,882 to 3,233 from 2012-2020 (including some employees that perform gas and electric functions).

O&M Expense Annual Totals



The next chart shows total O&M expenditures by FERC account code for the 2012 – 2020 period. Annual O&M expenditures during the period averaged about $231 million per year.

O&M by FERC Account



Key categories of expenditures, by percentage of total expenditures during the period included:

- Overhead circuit: 52 percent
- Substation: 13 percent
- Meters: 7 percent
- Underground: 6 percent
- Distribution Line Transformers: 1 percent.

These categories comprised nearly 80 percent of aggregate O&M expenditures with the remaining 20 percent attributable to other areas such as streetlighting and miscellaneous expenses.

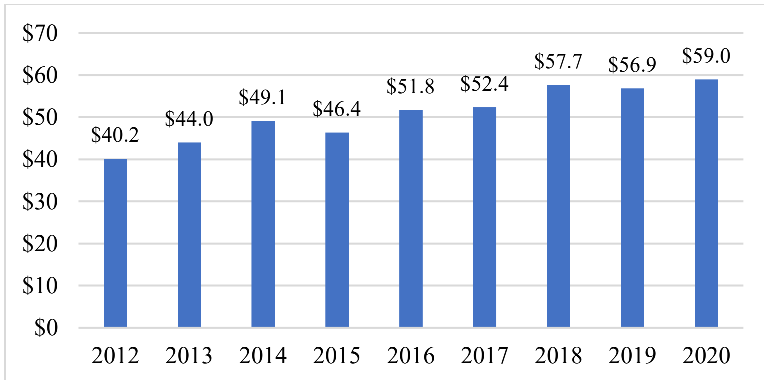
AIC tracks O&M expenditures by specific work order (WO) numbers (both O&M and capital). Specific WOs pertain to specific location and asset expenditures, while blanket WO's cover non-specific expenditures for repetitive expenditures and grouped activity tasks, such as general overhead repair/replace items, and storm restoration activity, for example.

AIC provided the WO detail level for O&M expenditures greater than or equal to $2 million, which accounted for 21 percent of total O&M expenditures. We analyzed the data provided for Vegetation Management and Storm Restoration, each of which generally had aggregate annual expenditures exceeding $2 million.

1. Circuit Vegetation Management

The following chart shows AIC vegetation management O&M expenditures for 2012-2020 using WOs with expenditures greater than $2 million.

Circuit Vegetation Management O&M



Vegetation management imposes significant needs on AIC. Management applies a four-year trim cycle on approximately 32,000 low voltage distribution (under 34.5kV) circuit miles of sub-transmission and distribution circuits that require vegetation management. The average annual $51 million in Vegetation Management expenditure comprised about 22 percent of total O&M costs. Vegetation Management O&M expenditures align with maintenance routines and reliability initiatives described later in this report. Vegetation Management expenditures arose under numerous blanket WOs, with 83 percent of the total attributable to the "Veg - Distribution Cycle Compliance" WO, implying that while there are numerous reasons for and varieties of vegetation management, the bulk of spending is geared mainly toward regular, annual execution of the distribution cycle program. The work orders for vegetation management include:

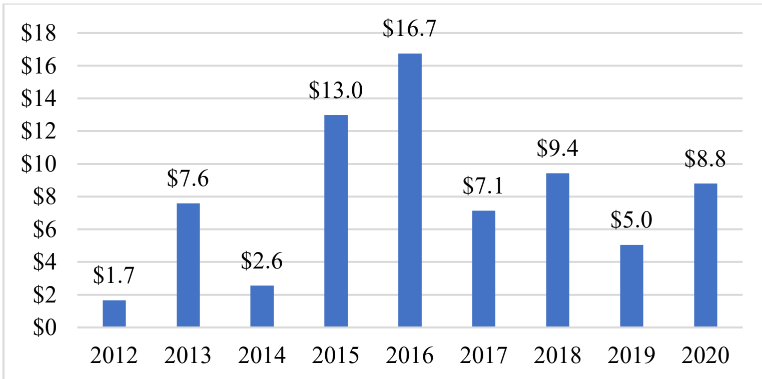
- Veg - AIC Vegetation - Reliability - WPC
- Veg - Customer Requests
- Veg - Distribution Cycle Compliance
- Veg - Midcycle Trimming
- Veg - Plan, Patrol, & Permit
- Veg - Reliability Trimming
- Veg - Risk Tree Mitigation
- Veg - ROW Maintenance, Herbicide
- Veg - ROW Maintenance, Mowing.

Vegetation Management expenditures exhibit variability due to external influences, but not to the extent that severe weather influences other O&M expenditures. Vegetation Management expenditures showed increases, attributable to some extent to improvements in maintenance routines and reliability initiatives, such as mid-cycle trimming, reliability trimming, and WPC trimming. Risk Tree Mitigation expenditures showed significant variability and rose notably over the last three years.

2. Storm Restoration O&M Expenditures

We also analyzed Storm Restoration expenditures. The following chart depicts annual "Storm Restoration" O&M, which exhibited significant variability.

Storm Restoration O&M



F. IIP-Related Capital Expenditures

AIC has reported on the annual status of its IIP since its inception in 2012, using a standard report format. Reporting has included mandatory key performance indicators (KPIs), referred to as the Multi-Year Performance Metrics, pursuant to ILCS 5/16-108.5(f) and supplemental KPIs, referred to as the Additional Voluntary Tracking Mechanisms.

One cannot meaningfully distinguish the size of IIP program investment contribution to system performance improvement from those produced by other expenditures and activities. Many IIP infrastructure investments represent incremental investment in similar non-IIP budget categories, further inhibiting distinctly valuing reliability contributions by activity or program. IIP initiatives can, however, significantly alter system characteristics that affect performance; *e.g.*, Distribution Automation enhances auto-response, while AMI enhances remote monitoring capability.

1. IIP Plan Description

The AIC IIP program included many components, identified in the following table by unique initiative designation and description. Some categories combine several items within a common category (*e.g.,* Infrastructure Improvement), while others stand alone (*e.g.*, Training Facilities).

IIP Plan Capital Expenditures 2012-2020

Subsystem	IIP Initiative	Improvement	IIP CapEx (millions)	Improvement Strategy System Characteristic Targeted
SubTransmission Substations (Bulk Substations)	1N	Expand Bulk Supply Substations	$30.2	Condition Exposure Reduction
	1E	Tie Line Capacity - Line 6973	$14.1	Redundant Configuration
	1L	Bulk Transfer Outage Mitigations	$8.9	Redundant Configuration
	3C	High Voltage Distribution Relaying	$6.8	Condition/Age
	1C	Bulk Substation Improvements	$4.3	Redundant Configuration
	1H	Replace High Voltage Distribution Breakers	$4.3	Condition/Age
		HV Substation Total	***$68.6***	
Distribution Substations	1A	Replace Primary Substation Reclosers	$30.5	Condition & Auto Response
	1D	Distribution Transformer Reserve	$26.6	Redundant configuration
	3D	Distribution Substation Metering	$3.7	Remote Monitoring Capability
	1B	Substation Animal Protection	$3.4	Exposure/Environmental Hazard
	1F	Substation Low Side Auto Transfer	$1.7	Redundant Configuration
		Distribution Substation Total	***$65.9***	
SubTransmission Circuits (High Voltage Distribution)	1M	Rebuild High Voltage Distribution Lines	$39.2	Condition/Age
	3E	High Voltage Distribution Automation	$18.5	Auto Response Capability
	1G	High Voltage Distribution Pole Reinforcement	$13.9	Condition Exposure Reduction
	5A	High Voltage Distribution Volt/Var Control	$7.5	Remote Monitoring Capability
		Distribution HV Circuit Total	***$79.1***	
Distribution Circuits (Primary Distribution)	3A	Primary Distribution Automation	$53.7	Auto Response Capability
	1J	Rebuild Primary Distribution Lines	$17.3	Condition/Age
	1K	Primary Distribution Lines Capacity Additions	$13.4	Transfer Capability/Capacity
	1O	Underground Primary Distribution Cable	$15.1	Condition/Age
	1P	System Tie Primary Distribution	$13.9	Redundant Configuration
	1I	Spacer Cable Program	$14.1	Condition/Age
	3B	Communication Infrastructure	$10.8	Auto Response Capability
	3H	Distributed Energy Resource Integration	$8.5	R&D Auto Response Capability
	3G	Underground Network Modernization	$5.6	Condition/Age
	5B	Primary Distribution Volt/Var Control	$5.0	Remote Monitoring Capability
	3F	Smart Grid Test Bed	$3.5	R&D Auto Response Capability
	1Q	CERT Remediation	$3.0	Condition/Age
		Distribution Circuit Total	***$163.9***	
Customer Meter	4	AMI Infrastructure	$305.6	Remote Monitoring Capability
General Plant/IT Software	6	Software and Technology Enhancements (ADMS, DEW Replacement)	$9.4	Remote Monitoring/Engineering Capability
Training Facilities	2	Facilities Improvements	$7.3	Training Facilities
Total IIP Plan			**$699.8**	

The plan included elements directed toward system infrastructure reinforcement, redundancy, and circuit automation; *e.g.*, auto-response. It also included system monitoring and software enhancements to enable advanced metering infrastructure, substation integration of automation and voltage optimization from DER penetration. Investment in training facilities and computer tools; *i.e.*, engineering, and operational tools, reflected the contribution of human resources as well.

The following table summarizes IIP investments by strategic intent and indicates shared strategies with AIC's non-IIP reliability investments, described earlier. IIP investments expanded the scope of the non-IIP reliability investments and shared common strategies for system reliability improvement fundamentals, such as the reduction of condition-based exposure, configuration enhancement, remote monitoring augmentation, and auto-response capability enhancements to the delivery system.

IIP Categories by Strategic Intent

Strategies of IIP Investments		Dollars	%
Condition/Exposure		$183.4	26%
Auto-Response/Automation		$83.0	12%
Configuration Related		$69.5	10%
Remote Monitoring	*SCADA*	$16.2	2%
	R&D	$12.0	2%
	Plant/IT	$9.4	1%
Transfer Capability/Capacity		$13.4	2%
Customer Metering	*AMI*	$305.6	44%
Training Facilities		$7.3	1%
Total		$699.8	100%

2. *Overlap of IIP and Non IIP Investment Categories 2012-2020*

The following table summarizes the overlap of non-IIP capital expenditure investment with IIP investments. We excluded non-IIP investments in New Business, Government Relocations, Storm, Office Fixtures, Land for clarity. Many of the initiatives had subsystem cross-over expenditures, making the table an approximation of expenditure targeting. For example, the sub-transmission tie line reinforcement included both sub-transmission line work and a new substation. Another example arises from the grouping of distribution automation investments, which required enhancements to substations to enable circuit automation protection coordination, with the circuit teams. Distribution automation included DER integration, which also crossed over with Volt/Var Optimization enhancement, where customer meter information comprises an input to area wide voltage schemes.

Non-IIP and IIP Capital Expenditure Category Alignment 2012-2020

Non-IIP CapEx		IIP CapEx	
Line Item (Budget Group)	**CapEx (millions)**	**Line Item**	**CapEx (millions)**
Circuit Exposure		**Circuit Exposure**	
E49 Transmission Line	$10		
E40 Electric T&D Line	$1	IIP Sub-Transmission Lines	$71
E46 Distribution Line	$571	IIP Distribution Circuits	$109
E42 Distribution Reliability Work	$599	IIP Distribution Automation	$114
Substation Exposure		**Substation Exposure**	
E63 Substation Distribution	$548	IIP Substations	$87
E60 Substation Transmission	$8		
Distribution Transformers		**Distribution Transformers**	
E21 Line Transformers	$154		
Electric Meters		**Electric Meters**	
E30 Electric Meters	$63	IIP AMI	$306

Other General Investments		Other General Investments	
E83 Other General Plant	1$30		
E84 Capitalized Software	$308	IIP Software & Technology	$9
Subtotal (selection)	$2,392	**Subtotal (selection)**	$696
Percent Total Non-IIP CapEx	71%	*Percent Total IIP CapEx*	97%

The preceding table groups the Non-IIP and IIP investments by subsystem to highlight capital expenditures in common subsystems. Most of the investments involved subsystems with the greatest exposure, *i.e.*, circuits, and lines. IIP distribution automation comprised an enhancement of subsystems capabilities to both High Voltage- Sub-Transmission Lines and Primary Voltage – Distribution Circuits. AIC's IIP investment represented about 30 percent of the above selected subset of the 2012-2020 capital investment. Much of the non-IIP spend resulted from condition-based expenditures originating from preventative and corrective maintenance activities.

From a reliability planning perspective, auto-response initiatives, like circuit automation, can frequently produce greater value when compared with other circuit subsystem investments. Auto-response initiatives do not change underlying system vulnerability to actual exposure from circuit miles and circuit device populations but improving the auto-response of the system can significantly reduce Customer Interruptions and Customer Minutes Interruption. Auto-response initiatives include "self-healing" circuits, additions of circuit mid-point reclosers for sectionalizing circuit protection, replacement of three-phase substation reclosers with single phase capability reclosers, and circuit lateral "smart fuse" replacements. Unique to these initiatives is an underlying technology advance that permits a reduction of impact for permanent faults and an auto-restoration capability.

IIP total investments also reveal AIC's focus on condition and exposure, and redundancy enhancements, while other IIP investments recognize the cumulative downstream benefits of higher-level system enhancements, *e.g.*, replacing high voltage breakers, and high voltage pole reinforcement. Other IIP expenditures targeted known asset performance issues, *i.e.*, spacer cable program, CERT remediation, and rebuilding of high voltage and distribution lines.

3. *Summary*

The IIP investment plan was consistent with strategies and aligned with AIC's system description, as described earlier, and consistent with strategies reasonably expected to improve overall system reliability. The IIP investments also appear consistent with fundamental reliability performance strategies and with KPI metrics embodied in the IIP performance-based rate plan, including objectives to accomplish advanced metering infrastructure objectives, reliability improvement, and system capability enhancement initiatives. Despite strategic intent, the total impact of IIP upon system reliability is unknown due to concurrent non-IIP investments and variable environmental hazards.

VI. Distribution System Condition

A. Summary

Chapter IV, *System Description and Configuration*, focused on describing the system, which changed over time largely through capital expenditures made to replace equipment, make new service connections, increase power transfer capabilities to meet increasing peak loads, address general load growth, provide 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"). System "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. The following observations relate to AIC's system condition during the 2012 through 2020 study period:

- While not a dispositive indicator of condition, the industry considers equipment age and aging trends one marker to consider. Based on the known age of older poles (~9 percent of total population), the total number of poles installed within the study period (~14 percent of the current system population), and the known ages of some voltage classes of substation equipment, we believe that AIC operates a large amount of aged equipment, and ages in some classes of equipment grew over our study period. AIC spent a considerable amount, about 22 percent of total non-IIP capital expenditures, on a typical range of programs and initiatives to maintain the condition of its distribution circuit and substation equipment.
- Annual capital additions to plant from Corrective Maintenance expenditures averaged $88 million/year, about 22 percent, of the total non-IIP capital expenditures during the study period. These expenditures are expected to continue and likely increase with aging infrastructure, and growth of asset bases.
- AIC added about an average of $200 million per year from 2012 through 2020 in reliability-improvement-based capital investment to plant (*i.e.,* combined non-IIP and IIP investment). AIC expects the non-IIP investment (~63 percent of the total non-IIP annual capital investment) to continue under strategic investment and reliability triggered initiatives.
- AIC averaged about $154 million per year in O&M distribution circuit preventive maintenance and corrective maintenance from 2012-2020. It spent about $30 million each year from 2012 through 2020 for distribution substation preventive maintenance.
- The system performance data we collected and analyzed (see Chapter VII, *Distribution System Performance*) show reductions in customer interruptions (CI) and customer minutes of interruption (CMI) caused by overhead and underground equipment. Overhead-equipment-related CI decreased by about 3 percent and CMI decreased by about 19 percent. Underground equipment related CI decreased by about 15 percent and CMI decreased by about 3 percent.
- We found inspection and maintenance programs comparable to other utilities whose practices we have examined, with examples including:
  - Four-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
- Twelve-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 processes to adjust equipment maintenance programs and to determine equipment end of life.

- Underground equipment inspection programs and the 2011 Energy Infrastructure Modernization Act (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 interruption.
- Underground equipment related CI decreased by about 15 percent and CMI decreased by about 3 percent.
- AIC increased vegetation management O&M spending by 48 percent from 2012 to 2020; the number of outages due to Tree Contact decreased by 22 percent. However, Tree Contact CI and CMI increased by 50 percent. The number of Broken Tree caused outages and CI nearly doubled. CMI in the Broken Tree category quadrupled (without exclusions for weather). AIC has noted, though, that its 2015 implementation of a new tracking system (ADMS) complicates the ability to directly compare 2012 and 2020 data. For example, ADMS creates separate orders for each phase on un-ganged devices, so outage events post 2015 often result in separate orders per impacted phase.

AIC 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. AIC installed approximately 180,000 (about 14 percent of the current pole population of 1.25 million) replacement and new poles over the study period. This 20,000 per year rate of pole replacement/new installation represents less than 2 percent of the installed base, implying an average age of more than 50 years for poles in service.

B. Introduction

Electric delivery system performance depends on asset condition. Delivery systems have evolved for over a century, and with long-lived but varied asset classes, equipment ages vary significantly both within and among classes. Age offers one indicator of system condition, but not a necessarily determining one. Holistically, condition derives from a large combination of factors, which include maintenance efficacy, changes in environmental conditions, and asset age. Maintenance efficacy must include consideration of the system environment as it changes due to highly local and more general factors.

Most 4kV distribution assets pre-date the advent of 12kV to 15kV construction, and 34kV construction generally pre-dates the advent of 69kV systems. Transmission voltages have also increased over time from 69kV to 138kV, and ultimately to 345kV transmission levels. However, generalizations about condition solely based on age are not probative. Older equipment often was designed with a greater performance margin, *i.e.*, more copper, or iron, or greater internal clearances, hence, these assets can be some of the most reliable. In addition, generally older lower voltage systems serve fewer customers, and inherently have less components to fail, *i.e.*, they generate lesser component exposure.

Utilities manage the condition of systems through maintenance programs, typically focused on time-based inspection and preventive maintenance (PM), and increasingly on condition-based maintenance. Keeping up with maintenance programs provides another indicator of system condition. Program status includes on-time completion of PMs and repair status, *e.g.,* corrective maintenance (CM), in accordance with policies for condition-based disposition, *i.e.*, either repair or replace. The stringency of embedded policies, guidelines, and criteria to remain relevant to system assets and their environment affects maintenance program effectiveness. Significant changes to program basis, policy or frequency, can result in performance improvement changes, just as a failure to keep pace with them can cause performance degradation.

Utilities generally operate some subsystems or assets intentionally on a "run to failure" basis, for example, when PM proves impractical or without demonstrable effect. Such strategies often apply when wear cannot easily be detected, where off-line maintenance would raise threats of unacceptable operating conditions, where sudden cascading failure modes present no warning, or when equipment self-reporting capabilities make the need for action evident. AIC distribution transformers and Supervisory Control and Data Acquisition (SCADA) systems fall into this category.

C. Asset Age

Many of AIC assets have unknown age, *e.g.*, material purchased in bulk or without discernable units or serial numbers. Primary wire, cable, crossarms, and poles frequently fall into this category. Legacy company reporting systems, or their lack, and paper-based data retention practices also prevent practicable retrieval of data to confirm asset ages. The AIC system encompasses more than 1.25 million poles; 63 percent have an unknown age. Of the known age population, 9 percent are sixty or more years old. Applying the same percentage from the portion of known age suggests the existence of 113,000 poles of at least sixty years of age. AIC replaced or installed an average of about 20,000 poles per year from 2012-2020.

AIC has much better information about the age of its major substation equipment. It knows the age of 98 percent of its substation transformer (<138kv) population and 100 percent of substation circuit breaker (<138kv) age. Substation transformers over sixty years of age comprise about 19 percent of the system population; the corresponding percentage of substation breakers stood at 29 percent in 2020. Newer technology substation reclosers (termed "Vipers") range from zero to 20 years in age. The next table summarizes Substation equipment age by voltage class.

Substation Equipment Ages

Voltage	Transformers		Circuit Breakers		Reclosers	
	Population	%>60 Age	Population	%>60 Age	Population	%>60 Age
4kV	381	33%	214	23%	0	n/a
12kV	85	11%	809	16%	505	0%
34kV	337	12%	419	8%	2	0%
69kV	175	14%	249	7%	0	n/a

1. *Calculating Plant Age*

AIC did not have data that permits direct measurements of equipment class ages. However, it does retain annual system asset inventories by asset account for rate base accounting. AIC also provides to the ICC an Illinois Annual Reliability Report, which summarizes asset aging and depreciated asset account value. This data also does not support direct measurement of age at any given point in time. However, the data can provide one measure of the change in age over a period of time, by comparing data from the reports for the first and last years of the 2012 through 2020 period The asset accounts align well with the subsystem segments we have used in this report to break down our analysis of the AIC distribution system.

Replacement of assets and reinforcement of the system, undertaken as inflation has occurred over time, has caused the net worth of the plant in service to increase by approximately $2.3 billion since 2012. Line items for each asset class show asset population and cost differences. The following table shows the inferred changes in equipment class age using Annual Reliability Report data. On an overall basis, this method shows essentially no change in system age when combining the classes shown in the table.

Calculated Changes in Plant Values and Ages by Class

Electric Delivery Subsystem	Description	Year	Plant In-Service (in millions)	% of Total Plant Dollars	2020-2012 Age Change
Land, Rights, ROW	Land	2012	$21	n/a	2.2
		2020	$25	n/a	
	Land Rights	2012	$10	n/a	7.7
		2020	$10	n/a	
Substations	Substation Structures	2012	$24	0.5%	3.1
		2020	$27	0.4%	
	Substation Equipment	2012	$771	16.0%	(3.3)
		2020	$1,350	19.1%	
Overhead Circuits	Poles and Fixtures	2012	$1,070	22.3%	(0.4)
		2020	$1,635	23.1%	
	Overhead Conductor and Devices	2012	$985	20.5%	(0.1)
		2020	$1,430	20.2%	
Underground Circuits	Conduit	2012	$100	2.1%	(0.2)
		2020	$141	2.0%	
	Underground Conductor and Devices	2012	$556	11.6%	3.1
		2020	$719	10.2%	
Distribution Transformers	Transformers	2012	$567	11.8%	1.9
		2020	$678	9.6%	
Customer Service Wires	Services - Overhead	2012	$182	3.8%	2.4
		2020	$230	3.2%	
	Services - Underground	2012	$186	3.9%	2.3
		2020	$261	3.7%	
Meter (AMI)	Meters	2012	$138	2.9%	(8.9)
		2020	$310	4.4%	
Customer Facility	Installations on Customer Premises	2012	$0	0.0%	8.9
		2020	$0	0.0%	
Public Facility	Street Lighting and Signaling	2012	$199	4.1%	(3.1)
		2020	$294	4.2%	
Total Plant In-Service Dollars		**2012**	**$4,809**	**$2,302**	
		2020	**$7,110**		

2. *Investment vs. Attrition*

The essentially flat customer growth over the study period, described earlier in this report, saw system expansion focused on local or regionalized pockets of growth. Nevertheless, AIC's delivery system did grow. The following tables summarize system growth for sub-transmission circuits, distribution circuits, and substations.

Sub-Transmission Circuit Mile Growth

Region	Overhead	Underground
North	175	2.2
West	342	0.5
South	195	27
East	280	1.1
Total	**992**	**31**
% of System Circuit Miles	**14.5%**	**0.5%**

Distribution Circuit Growth

Region	Overhead	Underground
North	90	147
West	89	158
South	28	116
East	203	163
Total	**410**	**584**
% of System Circuit Miles	**1.3%**	**8%**

The data in the previous tables and the *Calculated Changes in Plant Values and Ages by Class* table show consistency. Sub-Transmission OH circuit mile system growth of 14.5 percent and overhead circuit miles growth of 1.3 percent required plant investment in conductors, devices, and poles and a corresponding decrease in average age. The UG distribution circuit mile growth of 8 percent required a plant investment in cable and conduit. Underground conduit age decreased slightly.

Extensive substation equipment replacement investments in transformers, breakers, reclosers, and protective relaying also decreased average asset age. However, the average age of substation structures increased because investment in substation equipment outpaced investment in structures. AMI meter installation increased most dramatically in this period, again as shown earlier in the *AIC Distribution Plant Values and Ages* table, producing the greatest asset class age decrease.

Overall, AIC's electric delivery system investment, *i.e.*, the combined Non-IIP and IIP investment portfolio, partly driven by regionalized pockets of customer growth during 2012-2020, increased plant in service by almost 50 percent causing a slight decrease in the average age of system assets.

D. Maintenance Planning

AIC monitors asset deterioration to determine the nature and timing of repairs or replacements. Utility operating and maintenance programs employ periodic inspections for a wide variety of equipment types. They also use prescriptive approaches to certain periodic maintenance tasks.

These generally more invasive procedures often require removal of the asset(s) from service (*e.g.*, for equipment lubrication or diagnostic tests). Some preventive maintenance tasks occur seasonally (*e.g.*, building and equipment winterization; summer heat-related precautionary tasks such as transformer cooling fan functional tests).

Manned substations have become far less common in the industry and AIC utilizes none. Remote monitoring technology has supplanted on-site human observation. Equipment automation has also reduced some labor-intensive operating inspection routines, via embedded monitoring and communication capabilities. Maintenance practices have evolved with increasing use of self-monitoring assets. AIC separates maintenance into two main areas of activity. Preventive maintenance (PM), conducted proactively, includes equipment inspections and maintenance tasks, much like tire rotation or oil changes do in the automotive business. Reactive Corrective maintenance (CM) follows the discovery of unacceptable "as-found" conditions. Generally, the labor and costs of minor repairs comprise O&M expenditures. However, if conditions dictate, and the scope of corrective maintenance activities results in the replacement of an asset, costs may qualify as capital expenditures.

E. System Inspection and Maintenance Programs

This section describes AIC maintenance routines for sub-transmission and distribution circuit maintenance, for vegetation management, and for major non-equipment focused maintenance activity, in four areas:

- Program of Work: major maintenance activities undertaken for the system
- Milestones: key event timing
- On-Cycle Performance: degree of adherence to task completion on set cycles
- PM/CM trends (applicable for substations and OH circuit maintenance only).

We summarize significant changes to maintenance practices by year to show the contribution of changing maintenance regimes, describe general trends in maintenance programs and initiatives, and to correlate the timing of significant maintenance changes with system reliability trends.

We also highlight transitions from time-to condition-based maintenance, the penetration of self-monitoring equipment technology, improvement in equipment construction, and reduction of environmental impact as drivers of changing maintenance routines. We also address reliability impacts by interruption cause codes, *i.e.*, OH Equipment, UG equipment, substation, and tree related are also discussed (includes leading component failures).

1. Overhead Sub-Transmission & Distribution Circuit Maintenance

AIC's delivery system predominantly employs overhead configurations for both sub-transmission and distribution circuits, making maintenance routines similar for both. The program of work includes the visual and electrical condition of structural components, circuit devices, electrical components, public safety concerns, and environmental proximity conditions (*e.g.*, tree trimming, guying clearance).

a. Program of Work

AIC's Circuit Inspection Program includes periodic tasks, guidelines, and criteria that support classification of observations, and an accompanying prioritized schedule of repairs. Engineering guideline and specification documents provide maintenance and inspection criteria.

Visual circuit inspections, including infrared, take place on a six-year cycle for all AIC distribution circuits of voltage 2.4kV through 69kV.Groundline pole inspections employ a 12-year cycle and include a full groundline (sub-grade) excavation, bore and test with application of an insecticide/preservative internal chemical fumigant and an external preservative below groundline wrap. Groundline pole inspections expanded in 2018 to include a full groundline (sub-grade) inspection for distribution circuit two-, and single-phase circuit construction, replacing the previous method of sound and bore. In addition, Short Cycle Emergent issue inspection cycles occur annually for sub-transmission, and in two-year cycles for distribution circuits.

Circuit maintenance and inspection findings are documented and result in corrective actions, as necessary, prioritized by severity of condition. Emergency conditions on AIC-owned assets require one day corrective action, while all other priority codes require one-year corrective action. Action to address issues on jointly owned poles can take longer to accommodate joint utility coordination.

b. Milestones

Key milestones associated with sub-transmission and distribution circuit maintenance activities include:

- 2007
  - Pole Inspection and Treatment incorporated in Circuit Inspection Maintenance
- 2016
  - Short cycle emergent overhead inspection added to sub-transmission lines
- 2018
  - Changed visual circuit inspection cycle to 6 years from 4 years
  - Added short cycle emergent issues inspection for distribution circuits, every two years
  - Changed groundline inspection program to include full groundline test and preservative treatment of single and two phase poles; replacing previous method of sound and bore for single and two phase poles
  - Added pole treatment external wrap to all poles that are groundline inspected, now includes single and two phase poles
  - Update inspection schedule to balance workload by inspecting number of poles per circuit in an area as compared to number of circuits. Implemented circuits pass plan for 3 passes in an area to balance due dates.

c. On-Cycle Performance

AIC recorded timely performance of 100 percent of cycled preventive maintenance (PM) portion of the Circuit Inspection Program between 2012-2020 and for Corrective maintenance (CM) repair work resulting from the PMs for the sub-transmission subsystem.

d. PM/CM Trends

The next table shows the number of CMs resulting from the PM routine for the sub-transmission and distribution subsystems by region. Each sub-transmission CM comprises a circuit packet having multiple CMs. The data shows variability by region and by year in the CM circuit packet data for sub-transmission circuits. Distribution CMs expectedly outnumber sub-transmission CMs due to the relative circuit miles and numbers of circuits. The West region showed the greatest number of CMs over the study period.

Circuit CM Completion

Sub-Transmission Circuit CMs									
Region	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
North	0	7	7	50	2	6	18	18	15
South	17	17	16	42	15	14	24	24	12
East	14	20	26	38	14	13	15	15	20
West	30	35	38	107	37	38	43	43	36
Distribution Circuit CMs									
Region	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
North	132	305	181	150	101	95	132	60	76
South	213	176	275	185	130	133	116	138	114
East	74	134	109	128	84	141	51	72	58
West	281	391	584	529	377	552	600	387	289

AIC circuit maintenance involved significant O&M expenditure, averaging about $69 million annually. AIC overhead circuit inspections occurred as required by established cycles from 2012 through 2020. The nature and number of circuit CMs result from a combination of system condition and external factors that include, for example, severe weather and vegetation management efficacy. Chapter VII, *Distribution System Performance*, addresses the trends in overhead equipment caused interruptions.

2. Vegetation Management

a. Program of Work

AIC's vegetation management program runs on a 4-year cycle to manage vegetation growth in the proximity of AIC's overhead construction class facilities. AIC spent an average of $51 million per year on vegetation management during the 2012 - 2020 period, including all circuit subsystems. AIC classifies the annual trim cycle as equipment preventative maintenance, but treats weather-related damage to AIC assets, due to broken limbs and wind related breakage, as corrective maintenance. Mid-cycle patrol mileage was nearly equal to the trim cycle mileage in every year of the study period.

b. Milestones

The study period contained no notable milestones because the maintenance program remained relatively unchanged. However, in addition to the four-year cycle trim the program included the following:

- (2012-2020) Patrol for Tree-caused interruptions (≥ 100 customers) and trim CM review activity
- (2012-2020) Problem species removal, *e.g.*, Emerald Ash Borer damage.

c. On-Cycle Performance

AIC completed 100 percent of its target program for vegetation preventive maintenance (PM. Corrective vegetation maintenance, not subject to a cycle, consists of customer requests, storm events, and circuit CM inputs.

AIC vegetation management involved significant O&M expenditures and resource commitment to address a system with considerable vegetation exposure. AIC circuit inspections conformed to the established cycles during the study period. Chapter VII, *Distribution System Performance*, addresses trends in vegetation-caused interruptions. AIC's vegetation management routine reflects an effort to monitor the vegetation environment of its circuits.

3. Underground Circuit and Asset Maintenance

Underground Circuit and Equipment Maintenance on Underground Primary and URD equipment occurs primarily through annual visual and infrared inspections. Work scope includes primary underground equipment and conditions in manholes and URD equipment, *e.g.*, cable splices, network vault transformers, manhole conditions, URD pad-mount transformers, and URD sectionalizing equipment. The scope of inspection includes visual and infrared detection of physical, electrical, safety, and structural conditions.

a. Program of Work

Work scope includes annual visual and infrared inspection of underground facilities and underground equipment. Corrective maintenance is completed as it is identified or within 365 days for non-emergent conditions, *i.e.*, lower priority safety or operational issues.

b. Milestones

Management revised its Underground Primary Cable Replacement policy (CapEx program) to replace cable as of the first fault instance. The prior policy (2012 through 2019) permitted three instances of cable faults per section before replacement.

c. On-Cycle Performance

AIC's Underground Circuit and Asset Maintenance activities conformed fully to established cycles from 2012 through 2020.

4. Substation Maintenance

Substations contain discrete assets comparatively more easily maintained and presenting a smaller exposure to severe weather. Substation configurations provide greater redundancy and remote monitoring as compared with circuit subsystems.

Nevertheless, the number of customers and the complexity of the systems on which they depend create significant risks of adverse customer impact. AIC designed and operates its substation maintenance programs to monitor the condition of substation assets, considering timeliness, cost effectiveness, resource availability, and efficacy of underlying methods. Required substation CM types and numbers are influenced by system condition and by external factors (*e.g.*, severe weather, animal activity). AIC substation maintenance has generally occurred on-cycle. Chapter VII, *Distribution System Performance*, addresses the trends in substation equipment caused interruptions.

Unlike circuit subsystems, a substation contains a greater diversity of equipment types. Substation assets have a discrete identity, with individual serial numbers, and many moving parts subject to operational wear. These asset characteristics cause maintenance activities to rely more on invasive tasks and diagnostic tests. AIC's substation PMs have increasingly trended, consistent with industry wide trends, toward condition-based maintenance routines that reflect improvements in equipment technology, self-reporting equipment capabilities, and integration of IT technology that assembles enterprise-wide health-indexing information for maintenance management. PM tasks have also increased due to NERC security compliance requirements under evolving enforcement standards for relaying and critical equipment.

Developments at AIC reflect an industry-wide trend toward reducing environmental impacts. Many substation assets involved the use of environmentally hazardous substances as an insulating medium (*e.g.*, mineral oil). AIC substation maintenance, again typical of the industry, employs diagnostic and corrective tasks related to the assessment of the condition of the insulating media. AIC's investment portfolio during 2012-2020 included replacement of circuit breakers (*e.g.*, from oil to less hazardous sulfur hexafluoride (SF6) gas breakers for voltages of 30KV and above) to reduce environmental risk. Consistent with that trend, AIC substation maintenance has adapted to the environmental regulation of these assets, replacing many oil-based breakers.

Substations contain structures, *i.e.*, buildings, often referred to as control buildings, affording weather protection to control and protection assets, such as SCADA equipment. These buildings also require maintenance and, at a minimum, seasonal weatherization inspections to periodically monitor conditions such as security, rodent control, heating, cooling, and fire protection/alarm conditions.

a. <u>Program of Work</u>

AIC's substation maintenance activities include inspections and periodic tasks. AIC is engaged in a transition from periodic tasks toward condition-based maintenance tasks. AIC's Asset Performance Management (APM) software offers an asset database for the retention of asset data, substation maintenance data, health indexing data, and analytic tools for routine management. APM condition algorithms, using maintenance and diagnostic test results (automatic on-line or manual entries), issue out of tolerance alerts to Maintenance Engineering.

AIC substation maintenance activities in 2020 included PMs for the equipment shown in the next table. Many PM tasks are invasive and often require the equipment to be off-line to complete, for safety or to preclude inadvertent operation.

2020 Substation PM Tasks

ATO Switching Schemes	Breakers & Reclosers (<20kv)	NERC Equipment
Batteries	Regulators	Protective Relays -Transmission
Breakers (>20kv)	Transformers	Protective Relays- Distribution

AIC substation maintenance also includes diagnostic PM tests that the next table lists. In addition, substation maintenance includes PMs for substation visual inspections, which include monthly operating inspections and seasonal service inspections.

2020 Substation Diagnostic PM Tasks

Infrared Scanning – (thermal "hotspot") 1-year, all substations
Power Factor – (dielectric strength) cycle by equipment type and voltage class
Breaker Timing – 3- to 6-year cycle, by equipment type and location
Dissolved Gas Analysis (DGA, transformer insulating oil) – various intervals
Breaker Oil Analysis (BOA) – 3-year cycle, or by number of fault operations
Oil Quality Tests – laboratory tests, cycle by equipment type

b. Milestones

Key milestones during the 2012 – 2020 period included:

- (General) Trend toward standardized test procedures and digital record keeping. Substation maintenance became more condition based with a focus on input from subject matter experts and event history. Maintenance now employs algorithms with a focus on digital information, such as handheld data from relays.
- (2019) Implementation of Asset Performance Management (APM) software, an asset database, asset data, substation maintenance data, health indexing data, and analytic tools for routine management.
- (2020) Relay maintenance assessed for Reliability Centered Maintenance (RCM) to align intervals by failure mode history and self-reporting capabilities afforded by microprocessor-based relays (MPR).
- (2021) Testing transformers on a more frequent basis for detection of combustible gases. SF6 non-FERC circuit breakers (gas dielectric medium) – extended to a 12-year cycle based on reliability results.

c. On-Cycle Performance

In 2020, AIC completed 97.8 percent of all annual substation PM tasks and 87 percent of substation PM inspections. Management tracked the inspection portion of PMs monthly. Inspection PM records indicate that from 2015-2020, on-cycle performance ranged from 87 percent - 100 percent.

The following table shows PM maintenance performance by region for substation transformer and circuit breakers, major components of substations.

Transformer & Circuit Breaker PM Tasks

Percent of Substation Transformer PMs Completed within (or before) Target Year Due									
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
East Region	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	99.7%
North Region	98.5%	98.1%	96.8%	98.7%	99.7%	99.4%	96.6%	98.8%	96.5%
South Region	98.7%	100.0%	99.4%	100.0%	100.0%	100.0%	100.0%	100.0%	96.9%
West Region	100.0%	99.3%	100.0%	100.0%	99.0%	99.7%	99.7%	99.7%	96.3%
(no assigned region)	98.4%	97.7%	96.3%	98.4%	99.6%	99.2%	96.3%	98.8%	98.1%
Percent of Substation Circuit Breaker PMs Completed within (or before) Target Year Due									
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
East Region	100.0%	100.0%	100.0%	92.0%	95.2%	100.0%	100.0%	100.0%	100.0%
North Region	97.7%	81.0%	84.7%	82.9%	92.2%	96.7%	81.1%	87.8%	93.9%
South Region	99.3%	100.0%	99.2%	100.0%	100.0%	100.0%	99.2%	99.3%	96.8%
West Region	100.0%	98.7%	96.9%	100.0%	99.3%	99.5%	98.8%	100.0%	92.0%

The next table summarizes AIC substation maintenance CM tasks completion rates. Regional variability and emergency equipment prioritization is evident from the data with 95 percent of the CM replacements falling within the guideline replacement period for all regions.

Substation CM Tasks

Percent of Substation CMs Completed within (or before) Target Year Due									
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Emergency Equipment	n/a	100.0%	100.0%	0.0%	100.0%	100.0%	87.5%	50.0%	87.5%
East Region	73.6%	79.3%	79.7%	89.7%	92.9%	93.5%	88.1%	95.5%	79.5%
North Region	70.1%	60.4%	79.0%	85.1%	89.8%	88.1%	91.6%	85.3%	71.4%
West Region	82.3%	75.4%	87.2%	83.4%	88.2%	85.3%	83.6%	91.5%	77.7%
South Region	83.3%	73.9%	91.8%	96.2%	98.3%	97.2%	97.9%	93.2%	92.5%
(no assigned region)	n/a	100.0%	0.0%	0.0%	60.0%	0.0%	100.0%	0.0%	0.0%
Percent of Substation CMs Completed after Target Year Due									
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Emergency Equipment	n/a	0.0%	0.0%	100.0%	0.0%	0.0%	12.5%	0.0%	0.0%
East Region	26.4%	20.7%	20.3%	10.3%	6.4%	5.5%	10.8%	2.8%	5.6%
North Region	29.9%	39.6%	21.1%	12.5%	7.7%	8.8%	5.8%	7.2%	4.2%
West Region	17.7%	24.6%	12.8%	14.6%	9.9%	12.6%	12.7%	4.4%	2.7%
South Region	16.7%	26.1%	8.2%	3.6%	1.5%	2.6%	1.8%	4.5%	2.5%
(no assigned region)	n/a	0.0%	100.0%	100.0%	40.0%	0.0%	0.0%	85.7%	0.0%

F. System Interruption Data & Failed Component Detail

The next table summarizes AIC system's equipment related interruption impacts from 2018 through 2020, with component ranking by impact to Customer Interruption (CI) and Customer Minutes Interrupted (CMI). The equipment detail indicates which components most commonly failed, causing interruptions. Overhead primaries (wire down, broke, burnt, for example) proved the largest initiator, with poles second. These components undergo routine preventive inspections with identified repair needs scheduled and managed by priority.

2018-2020 Equipment Related Interruptions

Outage Cause (Rank)	CI Impact			CMI Impact		
	2018	**2019**	**2020**	**2018**	**2019**	**2020**
1	OH Primary	OH Primary	OH Primary	OH Primary	OH Primary	OH Primary
2	UG Primary	Pole	Fuse	Pole	Pole	Pole
3	Fuse	Fuse	UG Primary	UG Primary	UG Primary	UG Primary

This table confirms the system's most prevalent causes of interruption occur on OH circuit subsystems. It does not, however, impart OH component root cause information (*e.g.*, fuse coordination, rotted crossarm, broken pole, damaged lightning insulators). The data indicate that underground assets comprise one of three most common interruption related circuit components but does not convey UG component root cause information (*e.g.*, primary cable failure by condition, failed cable joints, underground fusing coordination, lightning damaged cable of equipment).

Compared to overhead circuit maintenance, AIC underground circuit maintenance represents a small fraction of total O&M expenditure and resource commitment - - not surprising given that AIC's underground circuit delivery system comprises only about 15 percent of the total system circuit miles. AIC circuit inspections matched cycle requirements during the study period. (Chapter VII, *Distribution System Performance*, addresses trends in underground equipment caused interruptions.)

Unlike AIC's overhead equipment maintenance routine, there are no associated equipment details for Vegetation Management. However, AIC does track Vegetation Management's impacts to the system and customers via two interruption cause codes: Tree Related - Tree Contact, and Tree Related -Tree Broken, and from CM review tracking. AIC's vegetation routine contains guidelines for clearance distances. Tree contact interruptions indicate "blue sky" (fair weather condition) reliability. Broken limb interruptions generally are more indicative of inclement or severe weather conditions. However, many communities contain established vegetation where trim or clearance distances do not eliminate proximate broken tree hazards, either vertically or horizontally.

Equivalent regional tables, presented below, reveal differences among the four AIC regions. Those with more urban and suburban URD exposure have greater incidence of UG related cause interruption. Rural regions have more incidence of lightning arrestor related cause interruption. In general, substation component related interruption impacts are lower than circuit impacts for all regions, but with regional differences evident. For example, the West and East regions show substation components among the top three ranked component causes; it is unclear, though, whether this is related to substation equipment condition.

2018-2020 North Region Equipment Related Interruptions

Outage Cause (Rank)	CI Impact			CMI Impact		
	2018	2019	2020	2018	2019	2020
1	OH Primary	OH Primary	OH Primary	OH Primary	OH Primary	OH Primary
2	UG Primary	UG Primary	UG Primary	Pole	Pole	Pole
3	Fuse	Pole	Pole	UG Primary	UG Primary	UG Primary

The North region experienced UG Primary as the second leading cause of interruptions due to greater exposure of UG circuit miles than in the other three regions.

2018-2020 West Region Equipment Related Interruptions

Outage Cause (Rank)	CI Impact			CMI Impact		
	2018	2019	2020	2018	2019	2020
1	OH Primary	OH Primary	OH Primary	OH Primary	OH Primary	OH Primary
2	Substation Misc.	Pole	Substation Misc.	Pole	Pole	Substation Misc.
3	Pole	Substation Breaker	Substation Breaker	OH Transformer	Recloser	Substation Transformer

The West region experienced substation causes as a second leading cause of interruptions due to greater exposure of 4kv and sub-transmission substations than in the other three regions.

2018-2020 South Region Equipment Related Interruptions

Outage Cause (Rank)	CI Impact			CMI Impact		
	2018	2019	2020	2018	2019	2020
1	OH Primary	OH Primary	Substation Misc.	OH Primary	OH Primary	OH Primary
2	Fuse	Lightning Arrestor	OH Primary	Fuse	Lightning Arrestor	UG Primary
3	Lightning Arrestor	Substation Misc.	Fuse	Pole	UG Primary	Pole

The South region experienced Lightning Arrestor as one of the second leading causes due to its greater rural OH circuit miles and unique hilly terrain than the other three regions.

2018-2020 East Region Equipment Related Interruptions

Outage Cause (Rank)	CI Impact			CMI Impact		
	2018	2019	2020	2018	2019	2020
1	1	OH Primary	OH Primary	OH Primary	Pole	OH Primary
2	2	Substation Misc.	Pole	Substation Breaker	OH Primary	Pole
3	3	Pole	Substation Transformer	Fuse	UG Primary	Crossarm

The East region experienced OH Primary leading causes due to its rural exposure of OH circuit miles.

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 our 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 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 AIC has undertaken and the rationales they have used to support them with what we have seen elsewhere. To the extent that they 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, as explained in those other chapters, found nothing unusual in areas or activities that AIC has pursued to improve its system performance. As this Chapter describes, we find that performance better for some indicators and worse for others, when not allowing for storm exclusion days. We believe it is sound to attribute performance improvement to the major categories of expenditures on which AIC has principally focused, while also identifying areas where performance improvement did not occur.

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 that program, while large in its own right, makes it more easily addressable in at least substantial isolation from other programs, projects, and initiatives.

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

- System reliability metrics with storm exclusions improved. SAIFI decreased (improved) by about 18 percent and System CAIDI decreased (improved) by about 11 percent.
- For system reliability metrics on a non-exclusion basis, SAIFI decreased (improved) by about 10 percent by 2020, but system CAIDI increased (worsened) by 50 percent.
- The greatest causes of customer interruption (CI) and customer minutes of interruption (CMI) during the study period were equipment malfunctions, trees, and weather. During the study period on a weather non-exclusion basis:
    - Overall, System CI decreased (improved) by 9 percent, while System CMI increased 45 percent (worsened).

  - Overhead Equipment was the largest cause of CI and CMI, contributing about one third of the impacts during the study period, but overhead equipment-related CI declined 2 percent and CMI declined 16 percent over the period.
  - Tree-related (combined causes) is the second largest cause of CI and CMI impacts, contributing about 23 percent of total CMI and 13 percent of total CI between 2012-2020.
  - Weather is the third largest cause of CI and CMI impacts, contributing about 19 percent of total CMI and 9 percent of total CI.
  - Substation impacts are the fourth largest cause, contributing about 6 percent of both CMI and CI totals during the study period. Substation CMI decreased 60 percent and CI decreased 5 percent during the period.
  - Underground equipment-related impacts are the fifth largest cause, contributing about 4 percent of both CMI and CI totals during the study period. Underground CMI declined 5 percent and CM declined 15 percent.
  - Animal Contact-related impacts are the sixth largest cause, contributing about 3 percent of both CMI and CI totals during the study period. Animal caused CI and CMI both decreased about 45 percent during the period.
- Distribution automation generally contributes to reductions in CI and CMI regardless of cause. Automation benefits were observed by the reduction of average customers per interruption from 40 customers/interruption to 30 customers/interruption between 2012-2020. But a reduction in customers/interruption via automation can also result in increased average minutes per interruption due to fewer number of customers; *i.e.*, reduced CI, but for which the outage time is more dependent on repair time, than quick field switching. Average CMI increased from 128 to 204 minutes on a non-exclusion basis when comparing 2012 to 2020 although the trend was uneven over the period.
- AIC reduced equipment caused outages during the study period by maintaining the condition of its distribution circuit and substation equipment at an O&M cost of $180 million a year as seen by improvements in Overhead and Underground, and Substation equipment caused CI and CMI.
- The number of Substation caused outages decreased 34 percent.
- The number of Overhead Equipment caused outages increased 17 percent, and Underground Equipment caused outages increased 8 percent.
- AIC has added mid-cycle patrols and proactive removals, and the number of tree contact outages fell by 27 percent. Broken limb tree related outages nearly doubled in the same period, but AIC noted that a change in process and recording contributed to the increase.
- AIC undertook system hardening measures and resiliency improvements, *e.g.*, installing stronger poles, replacing exposed overhead tree-wire, and installing lightning and animal protection. These efforts constituted about 8 percent of the total IIP capital expenditures.
- AIC's capital reliability investment included non-IIP and IIP initiatives. Non-IIP reliability investments averaged $127million/year from 2012 through 2020, while IIP investments averaged an additional $78 million/year during the same period.

- AIC's capital CM investment averaged $88 million per year from 2012 to 2020. These investments may continue or increase to replace aging infrastructure, guideline CM replacement requirements, and environmental hazard damage.
- Installation of substantial numbers of distribution automation "Smart Grid" automatic circuit load transfer schemes and improved substation protective schemes improved circuit protective device coordination, improved lateral tap circuit protection, and reduced the numbers of customers interrupted and minutes of interruption from each outage. Circuit automation represented about 6 percent of the IIP capital expenditures and AIC has automated 20 percent of its distribution circuits.
- Most systems include a small number of customers who experience an unusually large number of outages, and/or outage length, but not in magnitudes large enough to substantially affect system reliability metrics. These circumstances were addressed through initiatives and programs focused on the one-percent worst-performing circuits (WPC) and customers exceeding reliability targets (CERT). AIC's practices included replacing poorly performing overhead conductors, installing automatic circuit reclosing and load transfer devices, addressing tree issues, installing fiberglass cross arms, replacing overhead open conductors with tree resistance spacer cable, and installing underground cables to mitigate tree contact.
- AIC's number of CERT customers fell by 35 percent, from over 1,600 in 2009 to 1,095 in 2020. CERT frequency reportable customers were reduced from 92 in 2009 to zero in 2020.
- Other than for CERT, Worst Performing Circuits (WPC) programs, and those required by regulatory agencies, AIC prioritized reliability improvement measures, (*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 customer interruptions (CI) and customer minutes of interruption (CMI) avoided (prevented) each year post-completion of the reliability and resiliency programs.
- EIMA and non-EIMA programs contributing to the declining exclusion-based SAIFI, CAIDI metrics during the study period included:
  - Additional distribution automation devices, communications, and schemes
  - Improved animal protection and lightning protection
  - Improved substation relaying and communications systems
  - System hardening and resiliency programs and projects including reinforced poles
  - Replacement of poorly performing underground cables
  - Replacing weak decayed poles.

B. Performance Measurement Metrics Overview

The industry typically measures system performance using a variety of metrics. Some measures apply in aggregate for the system or for customers served. Some system measures focus on mid-level subsystems or aggregate for specific asset types, while others pinpoint specific customer experience types. Typically, judgments about electric delivery systems consider multiple measures, with no single one determinative sufficient by itself.

Four system indices (SAIFI, CAIFI, CAIDI, SAIDI, defined below) provide annual system level interruption measures. They measure the average annual frequency or duration of customer interruptions. SAIFI and CAIFI comprise the two most generally used measures of interruption frequency. System Average Interruption Frequency Index (SAIFI) measures the average number of interruptions per customer during the year. Its calculation divides the total annual number of customer interruptions by the total number of customers served during the year. Customer Average Interruption Frequency Index (CAIFI) measures the average number of interruptions per customer during the year. Its calculation divides the total annual number of customer interruptions by the total number of customers interrupted during the year.

SAIDI and CAIDI comprise the two most generally used measures of interruption duration. System Average Interruption Duration Index (SAIDI) measures the average number of Interruption minutes per customer during the year. Its calculation divides the total annual number of customer interruption minutes by the total number of customers served during the year expressed in minutes. Customer Average Interruption Duration Index (CAIDI) measures the average interruption duration for those customers who experience interruptions during the year. Its calculation divides the annual sum of all customer interruption minutes by the total number of customers interrupted during the year.

Number of customers interrupted (CI), number of customer minutes of interruption (CMI), and numbers of outages, termed "interruptions" (I), form the building blocks of system indices. CI, CMI, and I can be aggregated for the entire system, subsystem performance, specific root causes, or for customer groups, for example. They provide the ability to analyze interruption trends and underlying drivers that system indices cannot make transparent.

Asset overload measures comprise a mid-level annual measure for assessing utilization, electrical stress, and system power transfer and capacity margins of subsystems and assets. These measures vary due to the environment, particularly prolonged periods of excessive heat.

Circuit measures (*i.e.*, circuit SAIFI, circuit CAIFI, circuit CAIDI) offer mid-level subsystem annual measures, useful for characterizing the interruption performance of customers served by specific distribution circuits. Illinois electric utilities must measure circuit performance annually and report on the "worst one percent" circuits (WPC). These measures target customers experiencing service reliability well below annual system averages in a given year.

Customer level measures take on several forms but share a focus on specific customers experiencing interruptions or interruption minutes above a defined threshold over a specified period. At the system summary level, the customer experience curve aggregates numbers of customers experiencing ordinal values of interruptions per period. The curve plots the number of customers from zero to the highest value. This plot produces a diminishing tail, *i.e.*, the number of customers experiencing higher numbers of interruptions decreases as the number of interruptions increase. Improvement in performance measured this way comes through examining how that tail shortens from year to year.

C. AIC Delivery System Index Performance

The following table includes SAIFI, CAIFI, CAIDI and SAIDI for 2012 through 2020. The table provides values with and without Major Event Days (MED). AIC uses the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366 to exclude such days from its calculations.

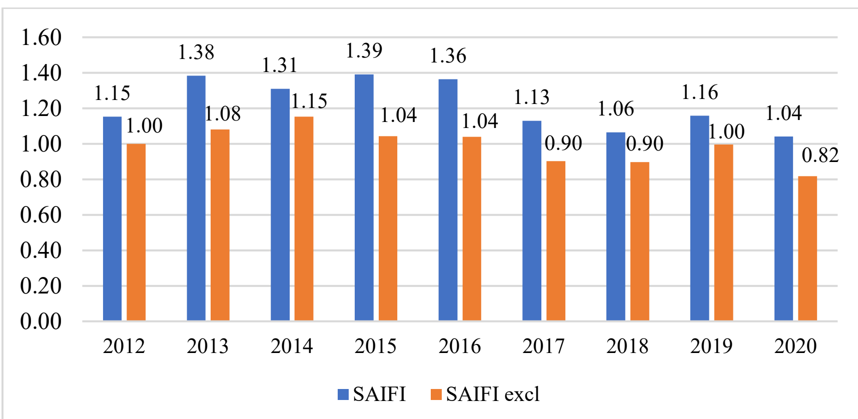
Typical of these measures, CAIFI values exceeded SAIFI values, and exclusion of MEDs had a greater impact on duration than on frequency measures.

System Indices 2012-2020

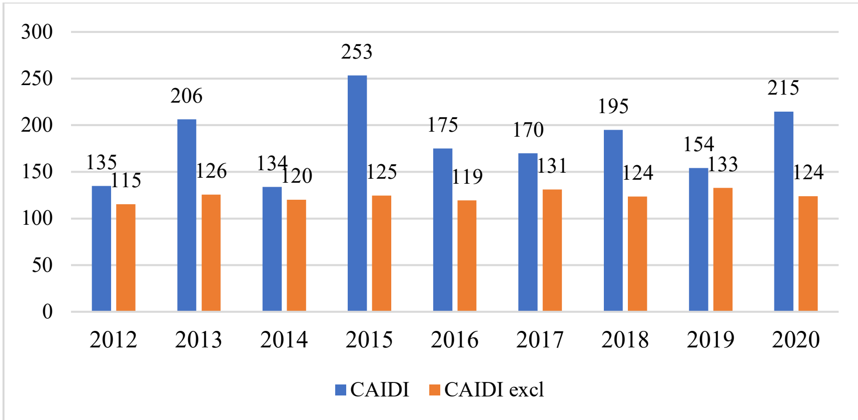
Including MED									
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
SAIFI	1.15	1.38	1.31	1.39	1.36	1.13	1.06	1.16	1.04
CAIFI	1.97	2.15	2.06	2.29	2.20	2.05	1.95	2.08	1.89
SAIDI	156	286	175	352	239	192	208	178	224
CAIDI	135	206	134	253	175	170	195	154	215
Excluding MED									
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
SAIFI	1.00	1.08	1.15	1.04	1.04	0.90	0.90	1.00	0.82
CAIFI	1.85	1.91	1.93	1.93	1.95	1.86	1.82	1.92	1.68
SAIDI	115	136	138	130	124	118	111	132	101
CAIDI	115	126	120	125	119	131	124	133	124

The following two charts provide a graphical depiction of SAIFI and CAIDI, with and without exclusions, and depict the trends from 2012 through 2020.

SAIFI 2012-2020



CAIDI 2012 – 2020



D. Customer Interruption Counts

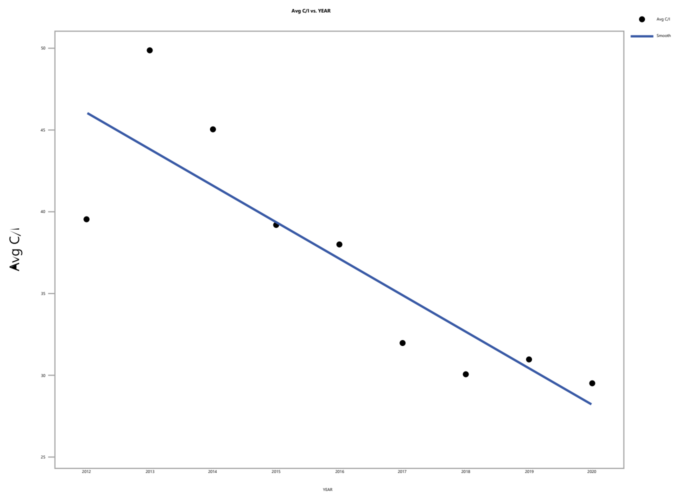
1. System Overall Trend Examination

AIC provides the ICC an annual summary of all interruption events by cause code within the Annual Reliability Report (411). The following table presents a summary of total Customer Minutes of Interruptions (CI), Customer Interruptions (CI), and interruption events (I) for the 2012 – 2020 period. The three columns on the right show calculated average customer minutes per interruption (Avg CM/I), average customers per interruption (Avg C/I), and average minutes per interruption (M/I). The data reflect annual variability and weather contributes to variability. The average customers per interruption decreased, consistent with increased penetration of automation and sectionalizing investments. The minutes per interruption, however, present an uneven trend, generally increasing over time.

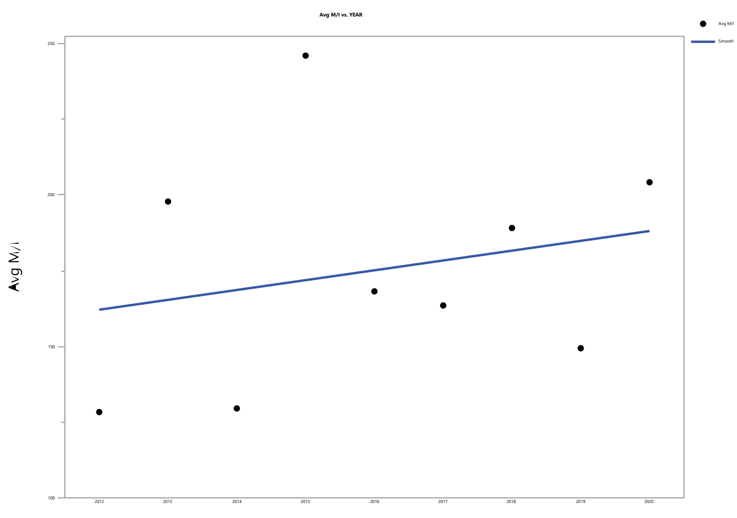
Customer Interuption Summary

Year	Total			Average		
	CMI	CI	I Events	CM/I	C/I	M/I
2012	192,269,442	1,498,310	37,897	5,073	40	128
2013	352,038,934	1,779,091	35,690	9,864	50	198
2014	216,772,588	1,673,489	37,167	5,832	45	130
2015	434,679,532	1,766,529	45,075	9,643	39	246
2016	295,235,920	1,755,297	46,192	6,391	38	168
2017	237,281,154	1,450,938	45,365	5,230	32	164
2018	258,253,048	1,365,439	45,399	5,689	30	189
2019	222,619,547	1,490,115	48,096	4,629	31	149
2020	279,428,246	1,368,161	46,337	6,030	30	204

Average Customers per Interruption



Average Minutes per Interruption



The trendlines for customers and minutes per interruption illustrate the year-to-year variability of delivery system exposure to the environment, and at the same time suggest the interaction of frequency and duration measures. Changes in system configuration as well as system condition, can result in a counter behavior, *i.e.*, a decrease in the number of customers interrupted but an increase in the minutes interrupted. The next section isolates some of the major drivers of variability in the above aggregate summary data and trends.

2. *Interruption Cause Codes*

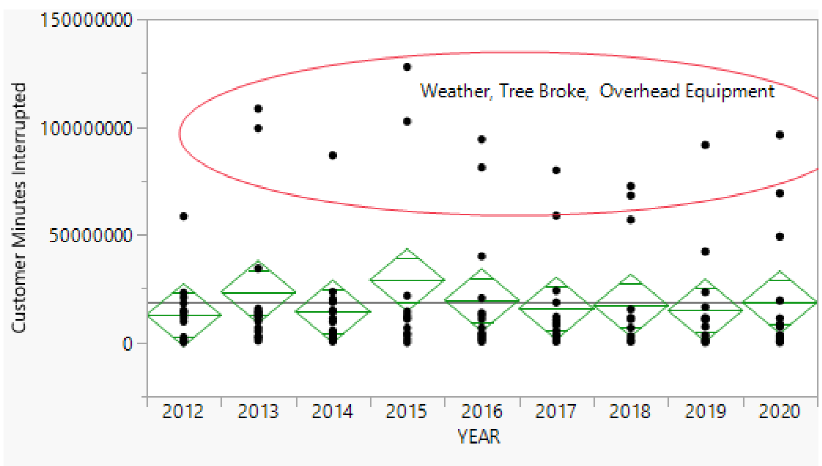
AIC assigns cause codes, shown in the following table, to interruption events. Major codes include weather, trees, overhead equipment, underground equipment, and substation equipment. We found four causes most informative in explaining interruption numbers and minutes. Overhead Equipment and Underground Equipment cause codes align with sub-transmission and distribution Circuit subsystems that earlier chapters addressed. The Substation code aligns with both sub-transmission and distribution substation subsystems. The Transmission code aligns with the transmission subsystem.

Interruption Cause Codes

Animal Related	Other	Tree Related - Tree Broken
Customer	Overhead Equipment	Tree Related - Tree Contact
Intentional	Public	Underground Equipment
Jurisdictional	Substation	Unknown
Loss Of Supply	Transmission	Weather

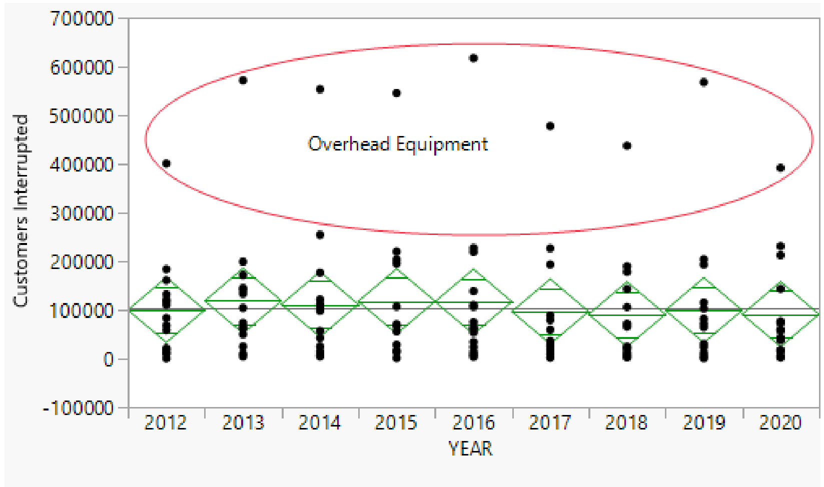
Across our study period, weather, tree broken, and overhead equipment stand out as leading causes of customer minutes of interruption. All three have a significant correlation with severe weather impacts, in terms of number of occasions, the severity of damage, and restoration times. The next chart, circling these causes in red, shows their comparatively greater effect when compared with other causes. The chart's lower section shows those other causes both much lower and tightly packed. The centerline of the green diamonds shows the changes in means each year from all causes (in the vicinity of 20,000 customer minutes), increasing through 2015 and then generally falling thereafter.

CMI by Cause Code



The following chart provides similar data for numbers of customers interrupted. The green diamonds there show stability in overall numbers, but the Overhead Equipment code shows as an outlying large contributor. While severe weather impacts are included here, weather and broken tree codes do not show as inordinately high contributors.

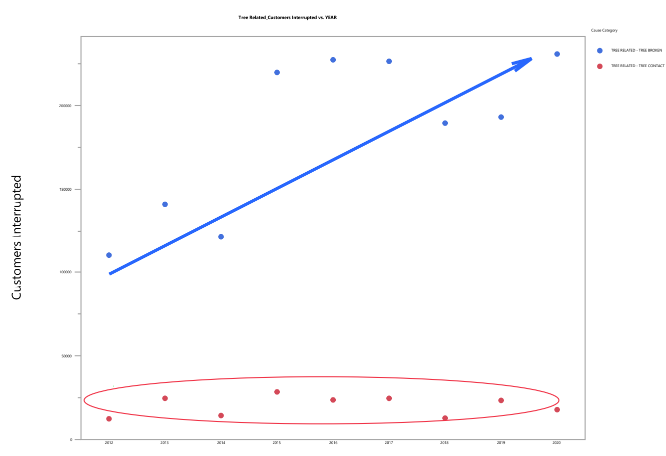
CI by Cause Code



E. Outages and Causes

The following chart depicts the number of customers interruptions related to Tree Related Cause Codes. It shows Tree Broken and Tree Contact categories, with the former, as explained previously, more likely to produce longer interruptions. The data show stability in the Tree Contact category, but high growth in numbers of customers interrupted assigned to the Tree Broken category.

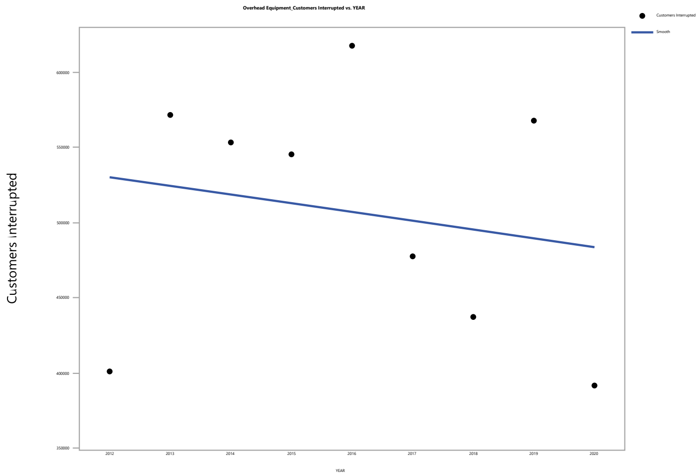
Tree Related Interruptions



1. *Overhead Equipment*

The next chart shows customers interrupted assigned to Overhead Equipment cause codes. AIC has invested in circuit automation and sectionalization and mid-circuit reclosers, including those with single-phase tripping capability - - investments that tend to reduce the numbers of customers interrupted by events affecting overhead lines and circuits.

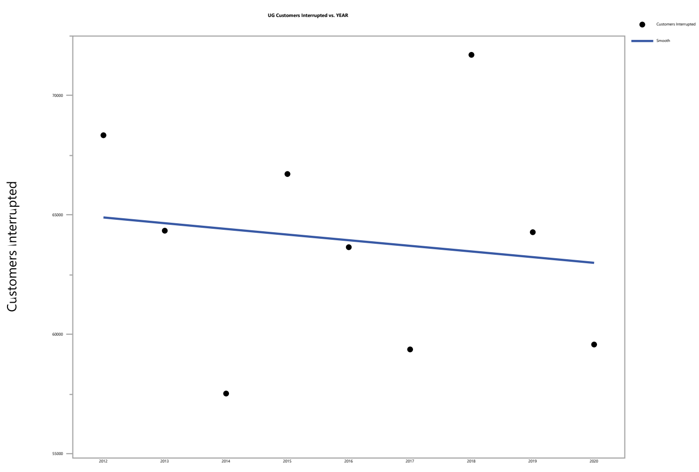
Overhead Equipment Related Interruptions



2. *Underground Equipment*

The following scatterplot depicts Underground Equipment caused interruptions. Underground subsystems do face some significant weather exposures, *e.g.*, excessive heat, that can result in thermal failure, and lightning surges and dig-ins also create risks. In general, the trend is improving. AIC has made changes to the underground failure replacement practices to initiate failed cable replacement upon the first failure.

Underground Equipment Related Interruptions

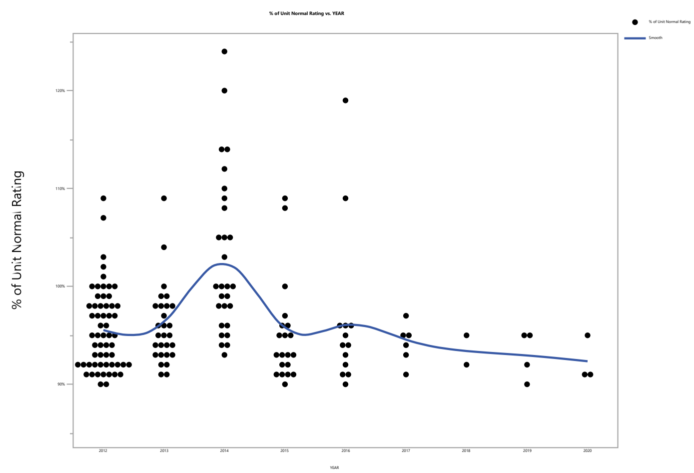


F. Equipment Overloads and Excessive Heat

AIC annually reports to the ICC system peak loading as well as an itemization of substation equipment overloads These loadings provide one measure of overall utilization of the system, threats to system failures from electrical overloads, and potentially cascading failures. It also provides one perspective on system planning, which uses load to identify needs for system reinforcement for expansion and load growth.

The following chart shows AIC's reported number of substation transformer peak loadings greater than 90 percent. They have declined significantly over the study period from 58 to 3 units.

Substation Transformer Peak Loads >90%



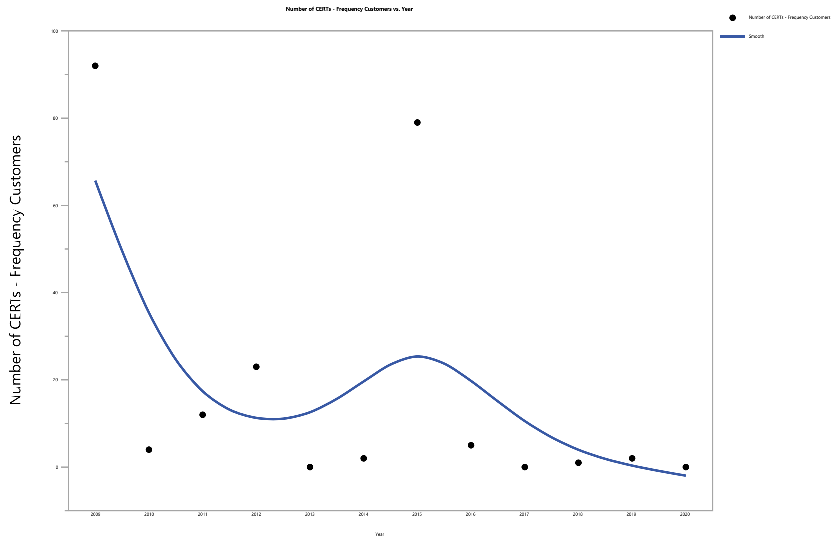
G. Worst Performing Circuit Metrics

Annual Worst Performing Circuit (WPC) reporting to the ICC addresses the one percent of each operating area's circuits, less than 15kv, with the worst performance. AIC must also report remediation efforts to improve the performance of those circuits. We examined data for 2018 for the 56 WPCs and performance for the two following years to gauge post-remediation performance. Analysis showed a reduction of 893 minutes of interruption in 2019 and a further reduction of 794 minutes in 2020.

H. Customers Exceeding Target Measures

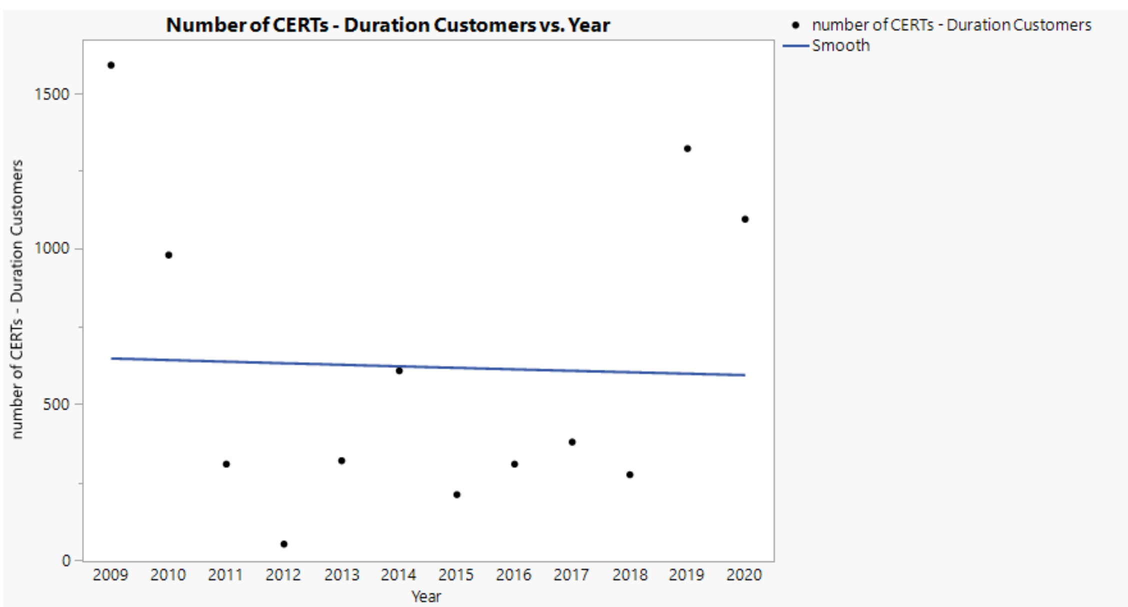
AIC reports numbers of customers that have experienced more than six interruptions per year (CERTS Frequency Customers) for three consecutive years or more than 18 hours of interruptions per year (CERTS Duration Customers). The following chart shows a reduction in the number of CERTS Frequency Customers - - to zero by 2020.

CERTS Frequency Customers



The numbers of CERTS Duration Customers displayed a modest improvement (declining) trend for the 2012-2020 study period as shown below.

Duration Customers



VIII. Advanced Metering Infrastructure

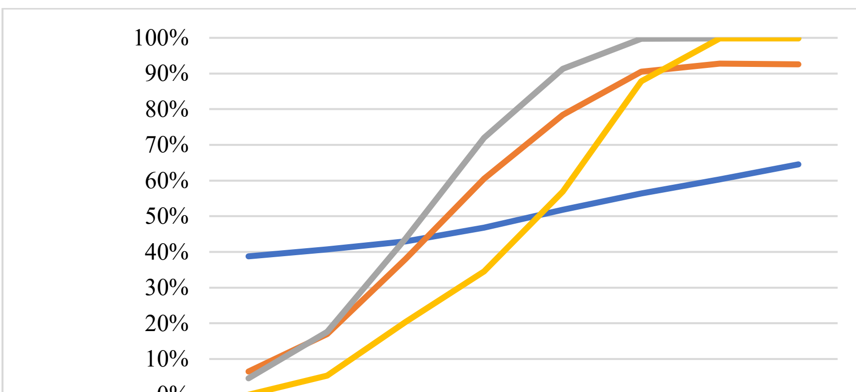
A. Summary

Advanced Metering Infrastructure (AMI), consisting of advanced or "smart" meters, linked together through communication networks, and supported by data management systems, comprises a key element of grid modernization. AMI facilitates timelier 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 the customer and the 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 Energy Infrastructure Modernization Act (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. AIC satisfied its EIMA AMI-related performance goals each year during the deployment without incurring any penalties.

EIMA provided AIC with pre-approved AMI-targeted expenditures of $305.6 million, with the company projecting 100 percent AMI deployment by 2019. By year-end 2019 AIC had achieved 100 percent AMI meter deployment (excluding non-standard metering customers and access issues). Program costs at the end of 2020 were on budget at $305.6 million.

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

B. Background

In the late 1990s AIC installed one-way automated meter reading technology on more than half of its operating electric and gas meters. By driving or walking through a neighborhood, AIC meter readers gathered electric and gas meter readings needed to support monthly usage billing.

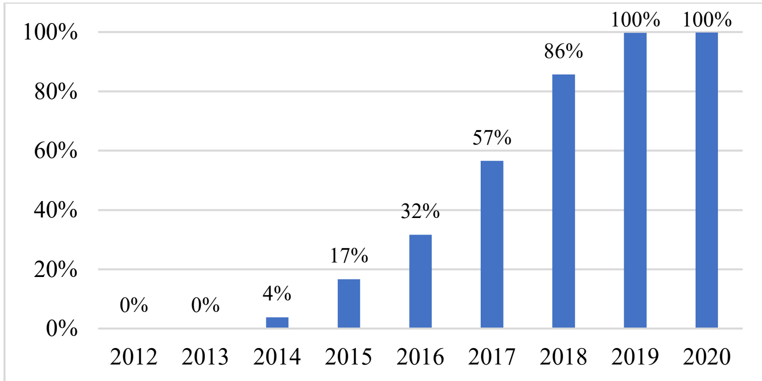
AIC committed to participating in EIMA and submitted an AMI Plan to the ICC in March 2012, detailing planned capital investments in AMI technologies over nine years to automate 62 percent of retail electric meters and 100 percent at 15 years. The Commission did not approve AIC's initial AMI Plan because it failed to meet EIMA's cost beneficial standard. Additionally, AIC proposed an implementation timeline longer than 10 years and included plans to replace gas meters - - neither contemplated by the statute. AIC filed a revised AMI plan in June 2012, which the ICC approved in December. AIC's revised plan included a deployment schedule beginning in the second quarter of 2014, still targeting 62 percent of customers. AIC filed in January 2013 a separate Gas AMI plan to deploy advanced gas metering technology to 56 percent of customers with combined gas and electric service.

AIC started AMI customer awareness and education in 2012. AIC selected Landis+Gyr as the AMI equipment vendor and Ecologic Analytics Meter Data Management System (MDMS) (acquired by Landis+Gyr) to support AMI meter data collection and storage. AIC began AMI network equipment installation in 2013 and AMI meter installation in 2014.

AIC filed a May 2016 request to accelerate and expand the deployment of AMI to 100 percent of electric delivery customers by 2019 and potentially recover its AMI investment before the formula rate ended in 2019. The ICC approved the expanded AMI Plan in September 2016.

AIC completed AMI meter installation in 2019. The next chart shows progress, as a percentage of AMI meters installed, from 2012 through 2020. AIC replaced nearly all electric meters within its service territory with AMI versions. As of the end of 2020, customers requesting or enrolled in non-standard metering numbered 3,101 - - approximately 0.3 percent of its customer base of 1.2 million.

AMI Meters Deployed by Year



Percentages are of total installed meters

C. AMI Program -- Progress by Year

Each year under the program, AIC coordinates with the Smart Grid Advisory Council (SGAC), a group comprised of nine voting members, with each member to possess either technical, business or consumer expertise in Smart Grid issues. Established by the Illinois General Assembly, five members are appointed by the Governor, and one each by Speaker of the House, Minority Leader of the House, President of the Senate, and Minority Leader of the Senate. In April of each year, after consultation with SGAC, AIC prepares and submits 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 program year involved planning and selection of technology vendors. AIC established a project management office (PMO) to oversee and support the initiative. Project team members, with the assistance of outside firm Accenture, reviewed existing business processes, recommended new and redesigned processes, and developed a schedule in preparation for AMI deployment. The customer research firm Market Strategies completed a baseline study of AMI customer awareness to provide a basis for customer communications efforts during the deployment. AIC created and issued Request for Proposals (RFPs) to select vendors to redesign business processes, to provide AMI technology and MDMS software, to integrate AMI systems with existing AIC systems, and to conduct ongoing customer segmentation research. The following table details 2012 year-end AMI deployment totals.

2012 Cumulative AMI Deployment

Measure	Status
AMI Meters Installed	0
AMI Meters Refused	0
% AMI Meters Actively Billing	0%
% Network Equipment Installed	0%
Total Capital Expenditures	$2.9 million

2. *2013 – Program Year Two*

AIC worked with IBM during most of 2013 to define systems integration requirements, identify organization impact for the deployment, and develop internal and external communications plans. To prepare for the deployment, AIC added AMI-related frequently asked questions to the public website and contracted with Aclara Technologies to develop a customer web portal interface to provide hourly data, bill alerts, bill history, green-button functionality, and home energy advisor. Green-button technology refers to industry standard methods for customers to download or connect to usage data in response to the 2010 White House call-to-action to make energy usage information more accessible to customers in a customer-friendly format. AIC deployed the head-end system and MDMS software supporting AMI operations in 2013and began initial field deployment of AMI network equipment in Hillsboro, Illinois. AIC created an AMI systems test lab in Collinsville, Illinois for testing the head-end system and MDMS and all network devices used to communicate with AMI meters. Management also solidified plans for AIC's Integrated Operations Center (IOC) to support AMI meter deployment and oversee AMI network operations following deployment. Ameren Information Security (IS) completed a cybersecurity risk assessment to identify requirements for the AMI infrastructure and overall cybersecurity plan.

Ahead of the deployment, AIC provided AMI videos and demos to employees to improve awareness of AMI technology and benefits and AIC communications highlighted AMI progress. AIC contracted with an external party to gather feedback from customers on AMI technologies and potential new pricing plans such as peak power rebates, load control programs, and real-time pricing. AIC filed a Peak Time Rewards (PTR) tariff in early 2013, designed to deliver credits to residential customers for curtailing electric usage during specific peak-time periods. AIC planned to open PTR registration to eligible customers in 2015. The following table details 2013 year-end totals for AMI deployment.

2013 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	0
AMI Meters Refused	0
% AMI Meters Actively Billing	0%
% Network Equipment Installed	5%
Total Capital Expenditures	$21.0 million

3. 2014 – Program Year Three

AIC began AMI meter deployment in the Hillsboro operating area. The IOC began operations, performing asset and configuration management, network monitoring and management, billing support, operations support, AMI deployment support, and firmware upgrades as needed. The IOC also established AMI analytics and reporting to track key program metrics. The AIC IS department enhanced the customer website to provide a portal for customers to review AMI usage data and billing history, utilize green-button functionality, and receive energy-saving tips and other information. The AIC team developed and issued numerous external communications to improve awareness of the program and technology.

To ensure AMI network security, AIC contracted with an external cybersecurity vendor to conduct penetration testing of the field AMI equipment. Additionally, AIC updated its Cybersecurity Plan and conducted risk and readiness assessments and vulnerability reviews of the AMI technology and systems. The following table details year-end totals for the program.

2014 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	46,940
AMI Meters Refused	27
% AMI Meters Actively Billing	3.8%
% Network Equipment Installed	5%
Total Capital Expenditures	$53.9 million

4. 2015 – Program Year Four

AIC exceeded its AMI deployment goals for 2015, installing more than 161,000 meters. AIC issued news releases and conducted radio and newspaper interviews to inform communities and customers about upcoming AMI meter deployment. AIC posted on social media platforms and sent customer emails to promote informational videos, self-service website tools, and cost and usage billing alerts. In October 2015, AIC encouraged eligible customers to participate in the PTR rate program.

Aside from field installation, AIC focused on green button functionality, operational analytics, and leveraging AMI to support outage response and remote connect and disconnects. To fulfill a customer request to start or stop service, AIC issues commands to the AMI meter to connect and disconnect service, eliminating the need for a field visit. AIC also issues remote service orders to perform cut-outs on delinquent accounts and to reconnect once a customer meets the payment criteria. During 2015, the IOC issued more than 10,000 remote service orders, reducing truck rolls and emissions. Also in 2015, AIC deployed alert and analytic software to monitor system health and to identify potential stuck meters or instances of theft. AIC leveraged AMI data to identify outages in its Advanced Distribution Management System (ADMS) and began installation of polyphase AMI meters for commercial and industrial customers. The next table details 2015 year-end totals for the program.

2015 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	208,214
AMI Meters Refused	197
% AMI Meters Actively Billing	16.7%
% Network Equipment Installed	47.5%
Total Capital Expenditures	$100.0 million

5. 2016 – Program Year Five

AIC continued integration of AMI and ADMS systems to support outage management, allowing dispatchers and field personnel to initiate on-demand meter status checks to verify restoration. IOC advanced analytics improved detection of inoperable AMI meters and potential theft situations and reduced work for back-office personnel.

AIC communicated with affected customers on pending AMI meter deployments and promoted the PTR program, through mail, email, radio, and newspaper channels. AIC also encouraged customers to create online accounts to gain access to energy-saving tips, learn more about available programs, and review billing and usage information. AIC introduced and promoted a process for customers to register and pair HAN (Home Area Network) energy monitoring devices with AMI meters. HAN compliant energy monitoring devices communicate with a smart meter over a home network to facilitate real-time display of a customer’s energy usage. As part of its enterprise-wide cybersecurity risk management program, AIC conducted cybersecurity assessments of the AMI infrastructure and enhanced security controls on AMI equipment to facilitate monitoring for suspicious and malicious activity.

In September 2016, the ICC approved AIC’s revised plan to expand AMI deployment to all customers. AIC installed more than 189,000 meters in 2016, exceeding revised implementation targets. The following table details 2016 year-end totals for the program.

2016 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	395,606
AMI Meters Refused	477
% AMI Meters Actively Billing	31.2%
% Network Equipment Installed	64.6%
Total Capital Expenditures	$138 million

6. 2017 – Program Year Six

AIC installed more than 300,000 meters in 2017, exceeding targets. AIC stimulated customer portal enrollment through social media posts, website, billboards, news releases, and radio and newspaper interviews. AIC operationalized green-button functionality on the website permitting residential customers to authorize and share data with registered third-party vendors. Additionally, AIC implemented a secure file transfer protocol to provide Aggregated Anonymous Data to third parties as required by the ICC, providing a year of anonymous customer usage data within a designated zip code.

AIC continued to fine tune operations using AMI analytics and increased savings through the elimination of truck rolls, faster identification of stuck meters, initiating follow-up on potential theft of service situations and inactive meters registering usage, and reducing back-office workload. The following table details 2017 year-end totals for the program.

2017 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	705,026
AMI Meters Refused	733
% AMI Meters Actively Billing	56.5%
% Network Equipment Installed	84%
Total Capital Expenditures	$204.5 million

7. 2018 – Program Year Seven

In 2018, AIC installed more than 360,000 AMI meters and performed 344,000 remote service orders. To support Voltage Optimization Operations (systematic controlled reduction in the voltage to a customer), AIC reprogrammed a limited number of AMI meters to provide 15-minute voltage measurement and sag/swell data. Going forward, AIC planned to program all new AMI meters to provide similar data prior to installation. AIC contracted with third parties to conduct penetration tests of the AMI solution from a corporate and field perspective. Ameren's IS team also scanned AIC's AMI network weekly for vulnerability via advanced endpoint security testing. The following table details 2018 year-end totals for the program.

2018 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	1,068,214
AMI Meters Refused	1,094
% AMI Meters Actively Billing	85.7%
% Network Equipment Installed	94%
Total Capital Expenditures	$260.8 million

8. 2019 – Program Year Eight

AIC completed AMI deployment in 2019, installing more than 170,000 meters. To support customer requests or billing needs, AIC completed 463,000 remote service orders through the AMI Network. To improve voltage optimization performance, AIC conducted AMI analytics on specific meters to identify voltage outlier candidates. AIC expanded the number of AMI meters capable of providing on-demand voltage readings through over-the-air programming and used voltage data from these meters to configure distribution system voltage regulators and load tap changes.

AIC promoted PTR and Power Smart Pricing programs through social media and email using targeted marketing to specific customer profiles based on "moments that matter," such as a new baby, empty nester, kids back home, and weekend warrior. As of March 2019, more than 100,000 customers registered for the PTR program. AIC also promoted customer portal enrollment linked with an LED light bulb incentive, resulting in several thousand new sign-ups.

AIC completed third-party penetration tests of the AMI infrastructure in 2019 and continued monitoring for suspicious activities. The next table details 2019 year-end totals.

2019 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	1,242,150
AMI Meters Refused	2,674
% AMI Meters Actively Billing	99.79%
% Network Equipment Installed	97%
Total Capital Expenditures	$295.6 million

9. 2020 - Program Year Nine

AIC completed more than 337,000 remote service orders in 2020. AIC conducted Over the Air (OTA) meter reprogramming to provide additional meter data needed to support voltage evaluation, measurement, and verification. AIC contracted with third parties to conduct two penetration tests of the AMI solution – one representing an external threat with access to the corporate network and the other simulating threats to the field network. The following table details year-end totals for the program.

2020 Cumulative AMI Deployment

Measure	Status
AMI Electric Meters Installed	1,243,704
AMI Meters Refused	3,101
% AMI Meters Actively Billing	99.84%
% Network Equipment Installed	98%
Total Capital Expenditures	$305.6 million

10. 2021 - Program Year Ten

AIC will provide the annual report for year ten of the program in April 2022. According to the Modernization Action Plan AIC has not planned any AMI capital investments in 2021.

D. Characteristics and Condition

1. Metering and Network Technology

AIC deployed Landis+Gyr AMI metering technology, head-end system, and Meter Data Management System (MDMS). AIC installed approximately 3,200 network gateways and collectors throughout its service territory. Additionally, AIC uses 14,000 network routers to communicate between network gateways and collectors to the company's head-end system and the MDMS. Meters record electric consumption in fifteen-minute intervals to facilitate monthly customer billing. AIC implemented automated Home Area Network (HAN) functionality in 2016 allowing customers to register and enroll approved energy monitoring devices through the AIC customer portal.

2. Coverage

AIC deployed nearly 100 percent of AMI meters throughout its service territory; about 3,000 customers have opted out of AMI meters in favor of non-standard meters. AIC deployed the AMI meters and supporting network and systems over a 6-year period from 2013 to 2019.

3. Performance

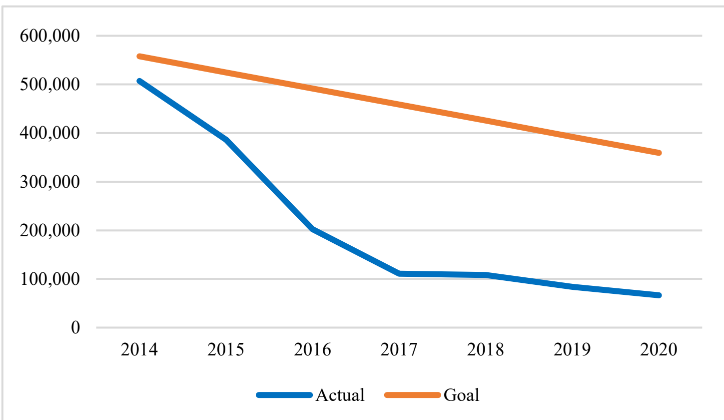
EIMA requires annual reporting documenting performance on multi-year metrics. The ICC approved AIC's Modernization Action Plan Multi-Year Performance Metrics Plan in January 2013. The plan included goals to reduce by year-end 2023, compared to baseline, the following three AMI related metrics:

- Estimated bills: 56 percent reduction
- Consumption on inactive meters (kWh): 56 percent reduction
- Uncollectible expense: $3.5 million reduction.

a. Estimated bills

AIC reduced the volume of estimated bills delivered to customers starting in 2014 when AMI meters began to come online. Over the subsequent six-year period, estimated bills declined from 3.5 percent to 0.45 percent of total bills. AMI meters gather customer usage data more effectively from meters through the AMI network rather than collected manually by meter readers. As a result, AIC billed more customers based on actual 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. AIC's AMI deployment reduced the level of estimated bills from more than 500,000 annually in 2013 to 66,000 in 2020.

Estimated Bills



Actual vs. Goal Estimated Bills

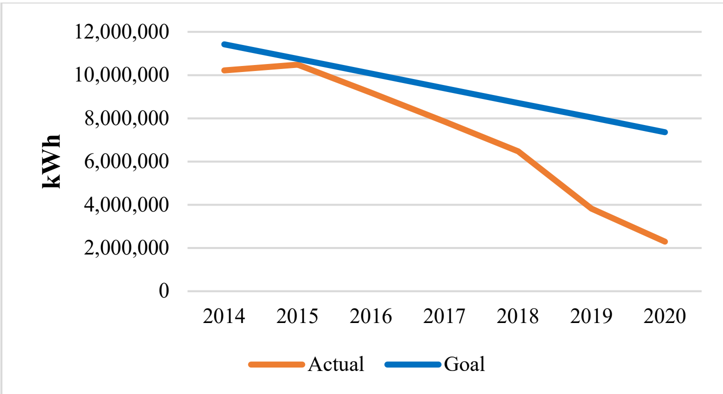
Year	Actual	Goal
2014	507,069	557,814
2015	386,095	524,724
2016	202,088	491,633
2017	110,981	458,542
2018	108,455	425,452
2019	84,018	392,361
2020	66,462	359,270
2021		326,180
2022		293,089
2023		259,998

As part of EIMA, AIC committed to reducing estimated electric bills by 56 percent over the 10-year period from 2014 to 2023. AIC's 2020 estimated bill performance surpassed the 2020 goal of 359,270 and the 10-year goal of 259,998 or fewer estimated bills.

b. Consumption on Inactive Meters

AIC considers consumption on inactive meters to occur when usage is registered on a meter at a location in which there is no customer on record to bill (measured from the time a customer moves out and until another customer moves in). Since 2013, AIC reduced consumption on inactive meters dramatically, from 11 million kWh to 2 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)

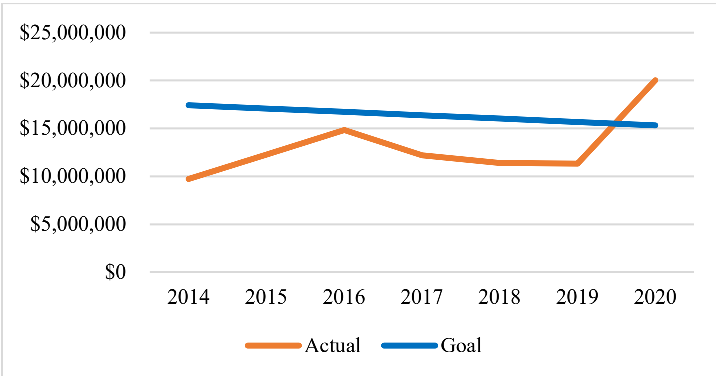
Year	Actual	Goal
2014	10,214,059	11,423,161
2015	10,481,629	10,745,516
2016	9,174,353	10,067,871
2017	7,851,923	9,390,225
2018	6,467,128	8,712,580
2019	3,824,172	8,034,935
2020	2,294,681	7,357,290
2021		6,679,645
2022		6,002,000
2023		5,324,355

In conjunction with its participation in EIMA, AIC committed to reducing consumption on inactive meters by 56 percent over the 10-year period from 2014 to 2023. AIC's 2020 performance surpassed the 2020 goal of 7 million kWh and the 10-year goal of 5 million kWh or less.

c. Uncollectible Expense

AIC defines electric uncollectible expense as customer debt owed but not collected after reasonable efforts. AIC'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 debt grew significantly during this period resulting in an increased uncollectible expense. In June 2020 the ICC issued an Order that allowed AIC and other large utilities in Illinois to accrue for service billed in 2020 but considered doubtful for collection once the disconnection moratorium expired in 2021 and disconnections resumed. AIC recorded a large accrual in 2020, reflected in the following chart and table.

Uncollectible Expense



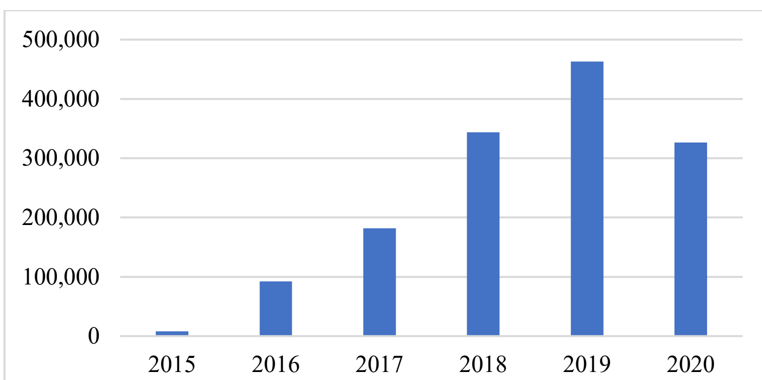
Actual vs Goal Uncollectible Expense

Year	Actual	Goal
2014	$9,729,979	$17,423,333
2015	$12,275,959	$17,073,333
2016	$14,829,652	$16,723,333
2017	$12,193,080	$16,373,333
2018	$11,390,890	$16,023,333
2019	$11,318,624	$15,673,333
2020	$20,029,448	$15,323,333
2021		$14,973,333
2022		$14,623,333
2023		$14,273,333

d. Other Operational Metrics

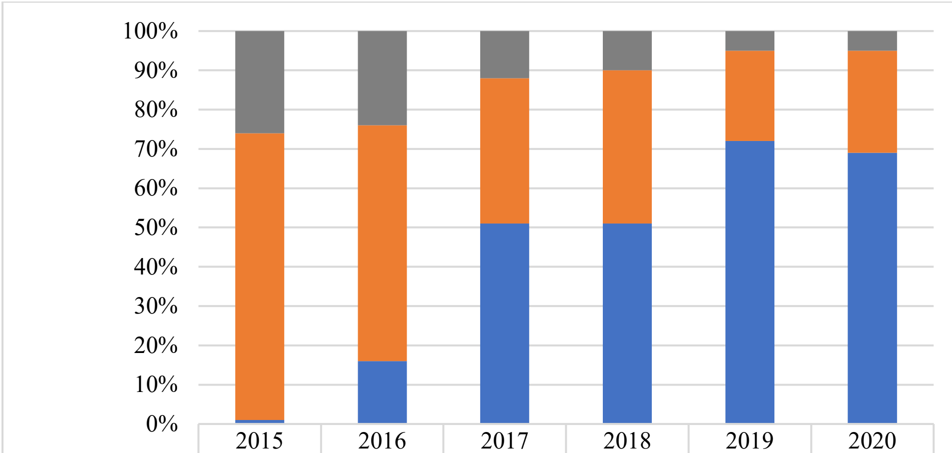
AIC's tracking of the number of remote service orders (*e.g.*, connects, disconnects) completed through AMI shows a positive trend. From 2015 to 2020 AIC completed 1.4 million remote service orders, eliminating the need to complete these orders in the field. AIC's remote service order functionality uses 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. AIC also uses this functionality to perform cut-outs on delinquent accounts and to reconnect once a customer meets 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 several options to alert AIC to an outage at their location: call the contact center, self-serve using a mobile app, website, IVR, or by texting "OUT." AIC tracks outage calls or notifications received by each communications channel. Since AMI deployment began, AMI outage notifications have increased significantly, reducing the need for customers to call or contact AIC through the various self-service channels. In 2020, AIC received nearly 70 percent of outage notifications from AMI meters. AIC's AMI and self-service notifications increased over the measurement period, reducing the need for customers to speak with a customer service representative.

Outage Notifications by Channel

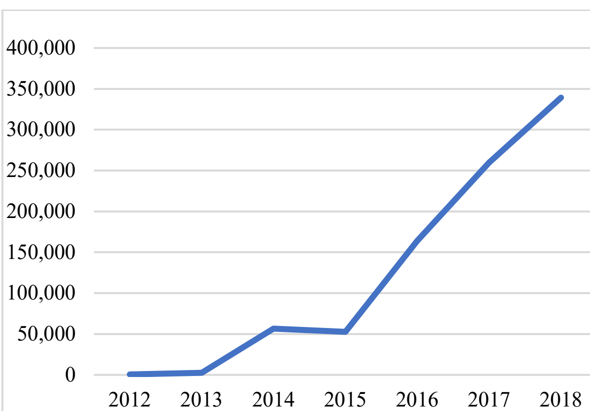


	2015	2016	2017	2018	2019	2020
Rep	26%	24%	12%	10%	5%	5%
Self-Service	73%	60%	37%	39%	23%	26%
AMI Meter	1%	16%	51%	51%	72%	69%

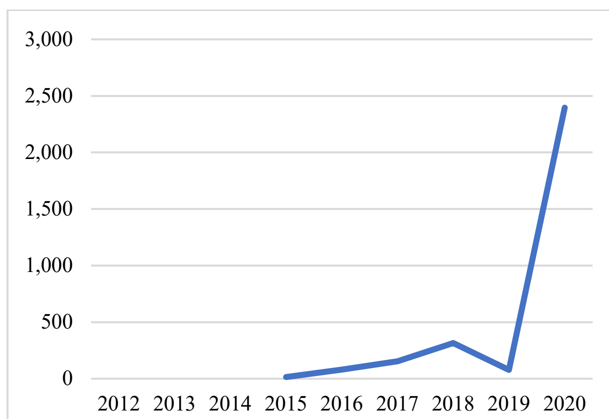
AIC enhanced its customer web portal in 2014 to provide customer access to AMI usage data, billing history, green-button functionality, and energy-saving tips. Customers accessing AIC's web portal increased quickly from 2017 to 2020, as more AMI meters came online and AIC encouraged customers to sign up and access the portal. Customers also access AIC's Green Button functionality to download usage data beginning in 2015, with usage peaking in 2020.

Unique Customers Accessing

Web Portal

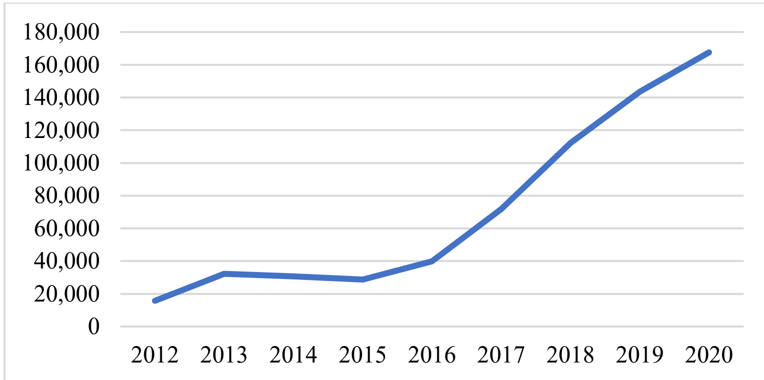


Green Button



Customer participation in Peak Time Rewards, Power Smart Pricing, and Real Time Pricing increased steadily since 2015, as seen in the following chart.

Customer Participation in Dynamic Pricing Programs



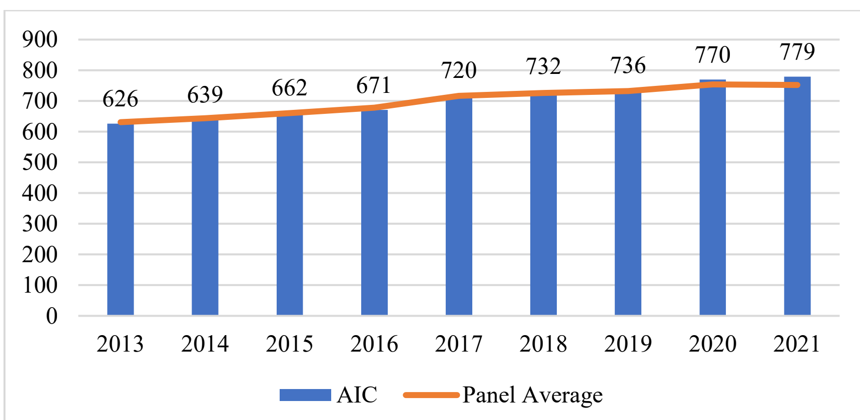
AIC received less than 500 AMI-related customer complaints during the 10-year deployment. The next table summarizes those complaints.

AMI-Related Complaints Received

2014	2015	2016	2017	2018	2019	2020
8	40	41	98	167	86	6

AIC's residential customer satisfaction improved steadily over the last 10 years, as measured by the J.D. Power Electric Utility Residential Customer Satisfaction Study (summarized in the next table).

Residential Customer Satisfaction



4. *AMI Network Performance*

AIC's IOC monitors the performance of AMI metering devices and network equipment. The IOC is staffed by 12 Ameren employees located in two separate locations maintained to facilitate business continuity and disaster recovery -- Decatur, Illinois and St. Louis, Missouri. Ameren's IT department and AIC Operations have a shared responsibility for the IOC.

5. *Cybersecurity*

AIC uses the National Institute of Standards and Technology (NIST) guidelines as the basis of its cybersecurity framework. AIC's AMI cybersecurity plan covers all aspects of the AMI, MDMS, and integrated systems, including meter security, data privacy and encryption, network device protection, firewalls, user access controls, security monitoring, and testing. AIC monitors the network for suspicious activities and conducts periodic penetration tests to identify areas of vulnerability.

6. Monitoring AMI Network Health

AIC's IOC monitors operations of the AMI network, including compiling metrics used to track performance, such as the number of remote connect and disconnect operations completed. The Ameren IT department tailored applications to monitor AMI network alarms and events to identify devices that are non-operational or improperly communicating with the network. The IOC tracks AMI network trouble tickets and network heath via dashboards and reporting. AIC strengthens any areas of poor coverage or weak response by deploying additional network equipment.

Detailed documentation developed by the IOC describes AMI operations, network layout and configuration, and provides guidelines to address operational issues. IOC reviews and updates AMI-related processes annually.

AIC's Volt/Var Project analyzes its electric grid to identify areas of inconsistency and poor network health so that reliability can be improved by optimizing voltage across circuits.

7. Failure Rates – AMI Meter Replacements

AIC replaced over 96,000 AMI meters prior to their end of expected useful life (20 years) since the start of deployment, as reflected in the next table. AMI meters replaced annually ranged from 0.1 percent in 2014 to 3.2 percent in 2018. Physically damaged meters (externally) represent the largest category of failure for the 6-year installation period.

AMI Meter Replacements

	2014	2015	2016	2017	2018	2019	2020
Meters Replaced	62	1,201	3,856	11,937	33,819	8,603	36,563
Meters Installed	46,940	208,214	395,606	705,026	1,068,214	1,242,150	1,243,704
Percent Replaced	0.10%	0.60%	1.00%	1.70%	3.20%	0.70%	2.90%

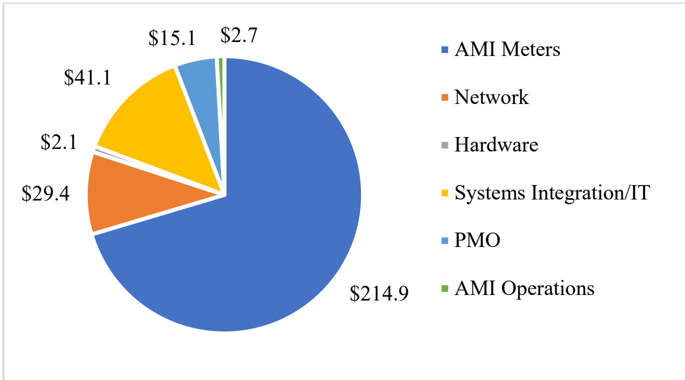
E. Capital Investment

Enactment of EIMA allowed AIC to embark on a multi-year Modernization Action Plan (MAP) which provided additional investment in infrastructure and training with reliability being a key driver. Following the passage of EIMA, AIC filed a proposed performance-based formula rate tariff, MAP – Pricing (MAP-P), in 2012, updated each year, under which it recovers electric delivery expenses. In each annual filing, AIC 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 AIC's Smart-Grid related investments detailed in its MAP. AIC submits annual reporting updating AMI expenditures and progress.

AIC's actual AMI deployment from 2012 to 2020 costs totaled $305.6 million. Meter Costs made up 70 percent ($214.9 million). Supporting hardware and systems totaled $43.2 million and AMI Network costs $29.4 million. The AMI capital investment represents about 43 percent of the total

EIMA Plan Capital Investment. AIC did not invest capital in the program in 2021. The next chart and table show this cost breakdown.

Total AMI Deployment Costs (in millions)



AMI Costs	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
AMI Meters		$0.2	$9.1	$28.7	$26.1	$61.8	$52.3	$29.1	$7.6	$214.9
Network		$0.8	$5.4	$4.7	$9.3	$2.6	$1.4	$3.2	$2.0	$29.4
Hardware		$1.7	$0.2	$0.2						$2.1
Systems Integration/IT		$12.1	$15.7	$10.7	$0.9	$0.3	$0.8	$0.6	$0.0	$41.1
PMO	$2.9	$3.1	$2.5	$1.9	$1.3	$1.1	$1.0	$1.0	$0.3	$15.1
AMI Operations					$0.3	$0.7	$0.8	$0.9		$2.7
Total Actual	**$2.9**	**$18.1**	**$32.9**	**$46.1**	**$38.0**	**$66.5**	**$56.2**	**$34.8**	**$10.0**	**$305.6**
Allocated Budget	**$2.9**	**$18.1**	**$32.9**	**$46.1**	**$37.4**	**$60.0**	**$56.5**	**$47.9**	**$3.8**	**$305.6**

F. Impact

AMI operational benefits of streamlined billing, reduced field costs, and improved outage detection and reliability began 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 the 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 (and in some cases even measure), 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 AIC's AMI Plan, approved by the ICC, holds AIC accountable for program spending and performance.

AIC's AMI Plan presented analysis in June 2012 demonstrating that the present value of benefits exceeds the present value of costs by $406 million over a twenty-year analysis period (2013-2032). AIC estimated total benefits of $1.277 million and total costs of $566 million over the twenty-year period. AIC's Plan identified many benefits associated with AMI deployment including:

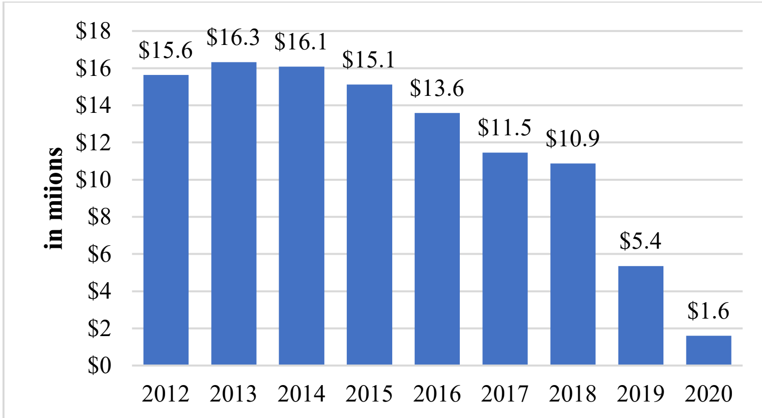
- Reduced operating expenses
    - Reduced field trips
    - Reduced meter reading expenses
    - Reduced field and meter services expenses
    - Reduction in unaccounted for energy
    - Reduced consumption on inactive meters
    - Reduced uncollectible expenses
- Efficiency improvements
    - Improved meter reading data gathering
    - Improved billing and customer management
    - Improved theft of service detection
    - Improved customer-facing technologies
    - Improved outage management
- Improved customer access to usage information
- Enhanced rate options and services
- Increased employee safety
- Job creation
- Reduced emissions through reduced truck rolls
- Enabling Voltage Optimization operations
- Supporting demand response, DER, and energy efficiency initiatives.

Analysis of metrics over the implementation period shows increasing benefits to the company, customers, and community. The prior section's charts and tables document AIC's performance on EIMA AMI-related goals – reducing estimated bills, reducing consumption on inactive meters, and reducing uncollectible expenses (excepting pandemic year 2020). AIC also demonstrated improved operational performance through the following metrics, 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.

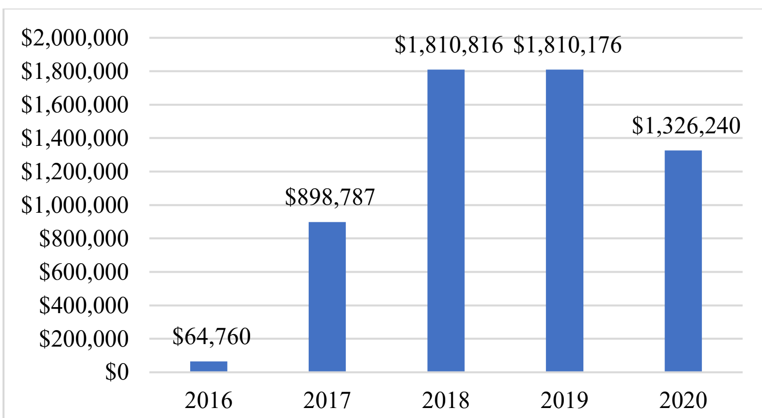
The next chart shows that AIC Meter reading expenses (FERC 902) began declining in 2014 and have continued to drop. Meter reading expenses have declined due to the installation of AMI meters and through a significant reduction of manually read meters.

Meter Reading O&M Expenses



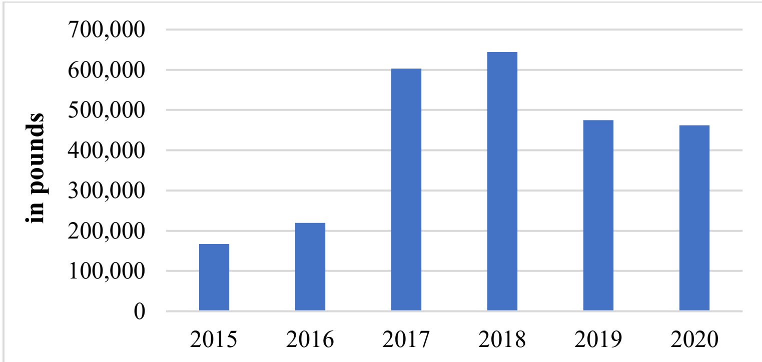
Beginning in 2016, AIC used data analytics to calculate the operational efficiencies made possible through AMI. Since implementation, AIC achieved annual operational savings through reduced truck rolls, reduced back-office work, and faster identification of stuck or dead meters and potential theft summarized in the next chart.

Operational Efficiency Savings



AIC identified further savings through reduced emissions, achieved through the elimination of manual meter reading truck gasoline consumption. Each year's reduction in greenhouse gases is shown in the following chart.

Reduced Greenhouse Gas Emissions



As a result of AMI implementation, AIC reduced operating expenses, improved operational efficiency, reduced greenhouse gas emissions, and expanded rate options and access to energy usage information for customers. Additionally, AIC 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

AIC has not specifically designed its distribution system to accommodate distributed energy resource (DER) integration, but it can accommodate those resources subject to appropriate analyses and study. AIC has developed processes for safely interconnecting DERs, including a DER Hosting Capacity Analysis tool under development to determine the amount of DER capacity that it can interconnect to each feeder without causing reverse power flow (a concern for circuits 15kV and below), voltage, or power quality criteria violations, or system infrastructure upgrades. AIC employs a formal process for reviewing DER interconnection requests and for conducting application specific studies required for approvals of DER interconnection requests. Total DER interconnections through 2021 amounted to approximately 240MW - - about 3.6 percent of its more than 6,600MW total peak load.

B. Determining the Ability to Interconnect a Distribution DER

DERs can add operational value to a distribution grid when contributing to feeder capacity, voltage control, and reliability. However, DERs cannot always be interconnected with the grid practically or economically. AIC's DER Hosting Capacity Analysis tool, under development, will determine the amount of DER capacity that AIC can interconnect to each feeder without causing reverse power flow (a concern for circuits 15kV and below), voltage, or power quality criteria violations, or system infrastructure upgrades.

AIC's cyclical system planning processes integrates DER penetration as an input to capacity planning. That planning process starts with load data collection from aggregate DER interconnection capacity (net kW) on a distribution feeder and known, anticipated new DER interconnections to ascertain peak and light loading conditions. Planning studies consider the aggregate DER impact upon feeder, unit, and substation loadings, to ensure the ability to provide service within applicable Illinois Administrative Code requirements, and to identify any indicated capacity relief plans or other system modifications.

C. Hosting Capacity

AIC developed a hosting capacity tool based on feeder analyses. AIC intends to publish separate "hosting" maps for systems 20kv and below, and for combined 34kv and 69kv systems, to determine DER size (kW) it can interconnect without negatively affecting the operation of the grid, local areas, feeder circuits, or immediate proximities to a specific address. Upon completion, the hosting capacity map tool will become available to DER developers and customers considering DER interconnection sites and size.

Several interconnection study considerations apply in ensuring reliable operation of the grid and compliance with delivery criteria. The DER interconnection circuit must remain within normal rating. The substation transformer rating and transformer nodes (primary voltage) must not exceed delivery thresholds and the voltage of circuit sections must not experience a 3 percent rapid change. Additionally, voltage regulators (equipment that regulates circuit voltage) must not experience a voltage change of 2 percent or more under a sudden loss of a DER, and hydraulic reclosers (protective devices where the automatic reclosing interval cannot be adjusted) must not experience reverse flow due to a DER operation.

System planning study objectives target the preservation of equipment; AIC relies heavily on circuit voltage regulation via voltage regulators. Electromechanical voltage regulators have vulnerability to operational wear and potential operational range-limit constraints from DER voltage contributions. Other study considerations target circuit protection; most of AIC's system operates radially, with normal power flow from the substation out to customer loads. DERs change the "paradigm" of the system model, introducing network flow that makes additional circuit protection coordination, reverse power flow, and short circuit impact studies necessary. Overall, the studies seek to ensure consistency with the provision of safe, reliable, and affordable electric delivery.

D. Distributed Energy Resources Interconnection Process

AIC reported that it currently has 240MW of Distributed Energy Resources (DER) interconnected to its system. It commences a DER interconnection approval and planning process upon developer or customer application for interconnection. DER connection requests initiate any studies required to understand how to prepare the distribution system for the interconnection sought. The results of these studies may require system modification, or iterative revision to the original DER plan, until reaching a mutually acceptable final plan.

E. DER Interconnection Planning and Approval Process

DERs are generally categorized as follows:

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

The Illinois Administrative Code Title 83, Part 466 for interconnections of 10MW or less, and Part 467 for interconnections of greater than 10MVA, govern DER interconnections. An interconnecting customer (IC) must design, install, provide relay protection, operate, and maintain its equipment in accordance with appliable standards and codes. The IC must also provide protection to the interconnected utility and its customers from faults and improper operations on the DER system and other detrimental grid operating conditions caused by the DER.

Depending on the kW or MW capacity of proposed DERs and on the determined effects on the distribution system, DER owners or developers have responsibility for costs to upgrade AIC's facilities to support the interconnection, including adding relay protection required to protect AIC's system, the installation of communication, telemetry, metering systems, and the relocating of facilities and upgrading AIC's system. DER customers must also make necessary changes to their systems if required by AIC due to 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 MISO, the regional transmission organization (RTO) that coordinates the movement of wholesale electricity for the Midwest region.

Review by AIC of an interconnection application may include technical review of the proposed DER, and depending on DER's size (*i.e.*, MW), short circuit, protection coordination, voltage, load flow, and stability studies to ensure consistency with AIC's technical requirements and to confirm the lack of impacts on AIC operations or other customers. AIC 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. AIC may also require review of relay settings and witness testing of DER operation and protective and control devices.

F. DER Additions and Investments

AIC's DER interconnections and energy additions remain very small relative to its peak load but have increased in the last two years. Residential solar interconnections have witnessed the most significant growth, as the next table summarizes. DERs interconnected in 2017 totaled less than 20MW and involved about 200 customers. Totals had reached 100MW and with 1,000 customers in 2019, expanding by 2021 to approximately 240MW and approximately 6,000 customers.

Interconnected DERs

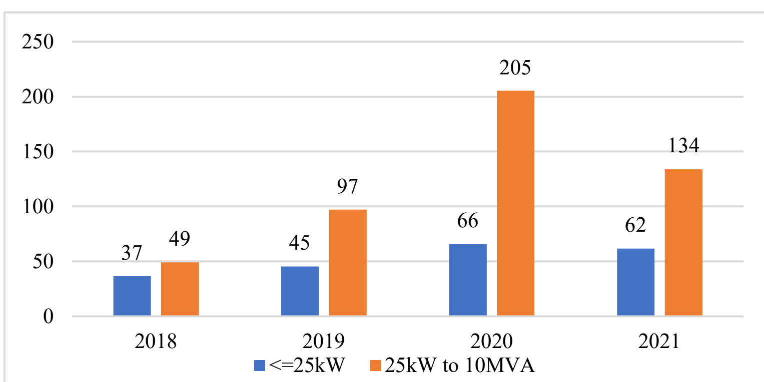
DER Type	Total Connected KW	Customers	Rate Class	
			Commercial	Residential
Solar	236,947	7,214	1,330	5,844
Other	1,108	67	57	10
Wind	488	95	23	72
Total	238,543	7,376	1,410	5,926

G. DER Applications

AIC has received over 5,500 requests for DER interconnection since its inception in 2008. As of February 2020, no customer requests had been denied since the start of the IEMA tracking metrics. This tracking covers about 63 percent of the total requests since inception.

The following chart shows the time between application fee payment and interconnection completion (as measured by test completion).

Average Days Between DER Application and Interconnection



X. Distribution System Planning

A. Summary

AIC 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.

AIC'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
- Temperature correct forecasts
- Identifying expected loading and voltage 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.

AIC's processes for planning capital projects and programs for reliability and corrective maintenance largely followed those applicable to capacity projects. AIC planning interacts with customers for new business, capacity expansion, and DER interconnection requests. Planning personnel also regularly engage with external urban planning resources to identify and gauge growth and mobility trends.

B. Introduction

The objective of system planning is to identify, prioritize, and authorize measures required to provide adequate electrical capacity and system voltages to serve AIC customer load with acceptable reliability, commensurate with cost. AIC system planning establishes criteria for the reinforcement and expansion of the system to ensure customer electric service meets applicable requirements and for the continued safe and reliable performance of the system. A fundamental design criterion for a distribution system is its capacity to deliver power to customers reliably under normal and contingency conditions.

AIC develops capacity relief plans or actions for circuits and substations forecasted to be loaded beyond design criteria. AIC's Distribution System Planning Department (DSP) has responsibility for planning the orderly and economic development of its 34.5kV and 69kV sub-transmission power supply system facilities, and for performing operational planning to assess reliability under near-term conditions. Planning's responsibility also includes maintaining adequate planning criteria and ratings, under guidelines established for system planning, engineering, and operation, as system configuration and equipment technologies continue to evolve.

DSP planning activities include the analysis and evaluation of the AIC sub-transmission system as it is affected by local and regional generation and sub-transmission system expansion plans and the impact of distribution system load activity through short-term and long-range planning studies. Sub-transmission system analysis proceeds in conjunction with internal transmission and distribution feeder planning studies.

Ameren Transmission (ATX) conducts transmission system analyses in coordination with the Midcontinent Independent System Operator (MISO), the regional transmission organization (RTO), to ensure compliance with North American Electric Reliability Corporation (NERC) Planning Standards, internal transmission planning criteria, and MISO planning criteria. These standards require that planning, design, and construction produce a system that withstand a variety of disturbances without experiencing overload of transmission elements, cascading interruptions, or uncontrolled loss of load.

Area planners (referred to as Region engineers or Regional planners as well) perform smaller, area capacity planning from regional offices, organized geographically into segments that share common substation and sub-transmission infrastructure and weather microclimates. Area planners address distribution equipment below 15kV, including substation transformers. The centralized system planning group oversees subsystems greater than 15kV.

Area planning encompasses the distribution circuit planning process and addresses the ability of feeders to operate effectively under known and anticipated loading and operating conditions. The goal of the planning process is to determine the means of providing reliable service to all customers, maintaining operating parameters within defined ranges under normal and contingency conditions and accommodating change in load. Annual feeder capacity planning studies take place in coordination with studies that address capacity planning for transmission, sub-transmission, and substations.

Area planners develop and propose various solutions to equipment capacity overloads and actual and projected criteria violations, including analyses of costs and consequences of not providing solutions. These solutions can include transformer additions, distribution automation, new feeders or extensions, feeder switching, phase balance, and capacitor installations.

C. System Capacity Planning

AIC system planning engages in many planning processes in addition to capacity planning for substations, substation transformers and distribution circuits. Other grid demands such as new business, public improvement requests, and internal reliability improvement require internal and external lead times to coordinate AIC (and customer) project selection, authorization, and construction.

AIC planners forecast substation transformer and terminal load growth by aggregating distribution circuit forecasted load growth upward to the (supply) substation and sub-transmission subsystems. They review historical feeder loads and loads projected for the plan's next calendar year. The Planners forecast substation terminal load growth for the next five years based on identified additions and load growth trends over the previous five years. However, horizons for larger addition can approach seven years to accommodate project development cycles. AIC develops distribution capacity plans at the area planning level to ensure review of all distribution system components for compliance with planning criteria. Distribution systems are generally limited by the lowest component thermal rating of the circuit.

Planners also review substation transformer conditions to determine whether to consider dual-purpose solutions that meet the need for capacity while improving material conditions. Typically, the least cost solution is selected, with other solutions considered if justified for operational reasons. AIC's C55 tool, a proprietary application that scores capacity relief alternatives with risk-based analysis, guides evaluation and comparison of potential solutions.

Planners develop area level plans, including circuit and substation maps, and a summary of forecasted circuit and substation loads before and after proposed capacity relief plans. Planning develops high level cost estimates for capacity relief projects projected for the following five years.

1. Long Range Capacity Planning

AIC's centralized distribution system planning group has responsibility for long-range distribution capacity planning of bulk power substations and coordination with transmission planning groups. Changes to substations require iterative coordination with area planners; load shifting among substations (new or existing) results in distribution circuit configuration changes. Preliminary and final substation capacity relief plans require area planners to update and confirm subordinate feeder configurations meet all planning criteria in the final plan.

2. Facilities Relocation Planning

Government Relocations projects address relocations of AIC facilities required for the "public interest." Public agencies, including the Illinois Department of Transportation (IDOT), the Illinois State Highway Authority, and county agencies may request such relocations.

3. New Business Planning

AIC must also plan for New Business work required to connect new customers, upgrade customer services, or relocate facilities at other than public authority requests. New Business work includes baseline projects (new capacity and customer-related system modifications). AIC develops planning options for baseline work on large new business projects, including budgets based on business economic models, historic baseline activity, and specific projects. AIC planners verify that new business capacity additions are integrated into annual capacity relief plans.

D. Distribution System Capacity Planning Process

1. Process Summary

Capacity planning operates on an annual cycle and produces short-term and long-term forecasts. The process employs a "bottom up" build of system loading that starts with the annual collection of historical load data from distribution circuits and customer delivery points. This data gets aggregated to nodes, *i.e.*, substation transformers and sub-transmission circuits, as determined by system configurations. Newly identified capacity planning needs supplement the historical data, addressing new business and facility relocation requests, for example. The summation of incremental capacity requirements and historical system loading gets entered into a load database for study and annual forecast development.

The database provides the front-end for computerized system models that, by simulation, determine system behavior under a variety of forecasted conditions and assumed system configurations. Annually updating system loading and configuration keeps study results responsive to changing circumstances and factors. This modeling, also known as load flow analysis, leads to a list of potential planning criteria violations prioritized by severity. Violations may include, for example, ampacity overloads, low/high voltage conditions, frequency deviations, reverse power conditions, excessive voltage regulator duty, reserve capacity loss, power factor, and phase balancing.

Capacity planners develop solutions to alleviate criterion violations, including reconfiguration, capacity additions (new circuits or substations), and equipment capacity upgrades, for example. Modeling applies these solutions to confirm their effectiveness in eliminating violations under an iterative process that eventually confirms feasible solutions. Candidate solutions become preliminary capacity projects for which planners, with input from other engineering disciplines, develop preliminary cost and schedule estimates.

An enterprise-wide process produces a selection of preferred options for assembly into a portfolio of capacity reinforcement projects, which then advance to the capital authorization process. Authorized projects advance to AIC design and construction processes.

2. *Process Elements*

a. Load Data Input

AIC collects load data from substations (in aggregate), transformer units, and distribution feeders. AIC has a number of host data systems from which it can collect the necessary data. A Load Analysis database operates as a central repository for informing load forecast studies. The database, updated at least annually, communicates forecasted load demands to Distribution System Planners and to system operators, who have access to the Load Analysis data directly and through linked computer tools. Distribution System Planners use the projected substation loads as input to sub-transmission and transmission planning models. The load forecast provides projected peak asset and circuit loading data, which then undergoes a process for determining coincidence factors for use in projecting peak load levels.

The Load Analysis tool compares peak substation transformer and distribution circuit loads with substation and circuit equipment ratings. The loads recorded are input into the Load Analysis tool by the responsible engineer after the system peak for that year occurs. The loads for the current season and the prior season remain in the Load Analysis program to provide a record of the most recent peak loads and equipment ratings.

b. Load Forecasts

AIC forecasts likely future peak loads using a range of assumed temperature conditions. AIC accounts for past growth, new development plans, other planned customer expansion, and forecasts by wholesale customers, consultants, or local and regional governments. Planners within AIC then analyze this data to determine where load is likely to 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 is needed.

The planning process begins with updates to the Load Analysis database. After data entry into the database, load forecasts that consider projected distribution substation loads, large customers taking delivery above 15kv, and wholesale customers, are developed and formalized. Sub-transmission model updates begin with the latest available transmission Multi-Area Working

Group case. DSP prepares plans for sub-transmission lines and substation locations along with number of feeders out of a substation. Area planning groups conduct similar analyses for distribution feeder planning. The two groups work in coordination to develop capacity plans for the AIC Distribution System.

c. Forecast Temperature Adjustment

Peak load forecasts are adjusted for a one-in-ten peak temperature adjustment. One-in-ten peak demand load forecasts are temperature adjusted for area specific historical temperature-loading data, to adjust actual load demand to mean temperature design load demands. Both summer high and winter low normalizing ambient design mean temperatures are specified for different geographic areas across Illinois. AIC's weather normalization adjustment also accounts for feeder saturation characteristics that classify the sensitivity of feeder circuits to summer air-conditioning and winter electric heating peak demands. The Load Analysis tool calculates temperature corrected loads.

d. Feeder Ratings

The maximum rated load that a feeder can carry represents the feeder rating. This can be a normal rating or an emergency rating, or it can be a summer rating or a winter rating. It is dependent on the current carrying capability of each component part of the feeder and normally starts in the distribution substation and concludes with the feeder backbone conductor and devices. The feeder rating is the rating of the portion of the feeder that has the smallest current carrying capability.

e. Load Flow Analyses

Distribution System Planners conduct annual system load studies using actual annual system load metering data, customer delivery point, and interconnection metering data in computer modeling tools to perform system analyses of equipment loading and other parameters. Those parameters include load flow, voltage stability, connected generation, and system stability. Multiple studies address several scenarios of system loading and contingency (*e.g.*, loss of an element(s) of the system, such as a line or transformer).

The purpose of conducting numerous studies is to identify criterion violations such as overloads, voltage violations, and negative conditions during a range of power grid conditions including normal, peak, low load, equipment contingency, system emergency, and other possible, although perhaps unanticipated, conditions and configurations. For illustration, we describe below two of the many load flow analyses studies conducted annually. However, as a family of studies, they enumerate loading and condition violations, which can identify a need to consider capacity reinforcement plans, and alternatives to remediate potential conditions illustrated by the study results.

A *normal study* of area system conditions considers all generation, transmission and sub-transmission facilities or components in service (*i.e.*, no contingencies) or are available for being placed in service to meet the system load condition. For the sub-transmission system, a one-in-ten-year load level forecast applies in evaluating the system. In this study the system model is initialized with all facilities in service and supplying the study area projected peak system load. The study requirement stipulates that the system shall operate with all equipment loaded at or below normal thermal limits and within voltage limits and enumerates all violations to the requirement.

A *single contingency* or *1st contingency study* of outage conditions involves the loss of a single sub-transmission or transmission component with all potential component losses studied individually. Such analysis evaluates the robustness of the study area system when experiencing peak system loading conditions while at the same time suffering an unplanned outage of a single system component. A solution could include operator intervention to re-configure the system post-contingency to re-energize equipment to serve connected loads during the outage of a single system supply component. Again, the study requirement stipulates that the system shall operate with all equipment loaded at or below normal thermal limits and within voltage limits and enumerates all violations to the requirement for analysis.

f. System Modeling

AIC employs two load forecast modeling tools for load flow studies - - one for distribution circuits below 15kV and a separate one for circuits above 15kV. Both of these tools support load flow studies and assess conditions with and without proposed capacity planning solutions. The Load Analysis database, as noted earlier, contains load information for all distribution substations and supports planning, project identification and budgeting. The load information contained in the Load Analysis Database is collected by the appropriate regional engineer and presented at annual regional meetings. Potential projects undergo cost/benefit evaluation followed by submission into the budget process considering viable candidates. Distribution substation equipment and circuit loading information contained in this database is used by the Distribution System Planners to update load-flow models and identify projects at the sub-transmission and bulk substation level.

g. Other Technical Studies

Distribution circuit planning studies that examine annual loading and anticipated future loadings at times require changes to existing distribution circuit configurations. Feeder planning determines changes needed to accommodate a new feeder. After establishment of a feeder plan, the new circuit configuration undergoes analysis to verify that the feeder will operate properly for loading and coordination purposes (*i.e.*, the ability to isolate feeder faults to preclude slow isolation or over-isolation outcomes).

Distribution planners analyze existing feeders to verify expected loading and voltage drop on the planned feeder and conduct a fuse coordination study to identify potential device coordination issues (*e.g.*, ensuring that circuit branch fuses isolate with proper timing to preclude over-isolation of an upstream device). Studies also consider other equipment rating and operational considerations, such as recloser and circuit breaker cold load pickup ampacity, phase balancing, reverse power flow, power factor, etc.

h. <u>Reserve Capacity Adjustments</u>

After peak loads are determined and estimated load growth is taken into consideration, attention turns to possible customer reserve requirements. Reserve requirements are needed by customers who have contracted with AIC to provide an alternate supply through an automatic or manual transfer switch if the customer's primary source becomes unavailable. Reserve requirements for customers are then placed on the feeder. These locations are identified by feeder maps for customer locations that are serviced by multiple feeders. These locations are checked using mapping of 3-phase tie switches or primary metering points on the feeder. Color coding of feeders identifies common points with other feeders at a customer premise.

E. Capital Project Screening and Authorization Process

1. Work Plan Prioritization and Funding Authorization Process

AIC prioritizes work using a proprietary tool to identify the need, assess the risk score, and prioritize system investments and initiatives. The tool provides senior management with the means for leading the decision-making process of optimizing the portfolio of investments. The tool supports ensuring that projects are appropriately prioritized consistent with approval and authorization process, and that the desired delivery system functionality is achieved at least cost, without causing safety, environmental, or reliability issues. AIC uses the work plan prioritization process to review the projects and to assess the risk scores, and to challenge assumptions used to determine the probability of failure and the probability of consequences. Selected work receives authorization for funding by business line and gets included in AIC's financial forecasting systems.

2. Screening and Authorization

AIC conducts screening and ongoing capital authorization processes for large projects. A Corporate Project Oversight Committee (CPOC) reviews projects $20 million or above, a Senior Leadership Project Oversight Committee reviews projects between $5 million and $20 million, and a Business Line Oversight Committee reviews projects between $500,000 and $5 million. AIC's capital screening and authorization processes for projects and programs costing more than $100,000 in capital and O&M include evaluations and authorizations of proposed and on-going capital projects and programs by the Central Review Committee. The processes allow senior management and executive leadership to control project scopes, costs, contract strategies, budget developments, project scheduling, etc., to keep overall capital investment planning on target. The primary goals of the processes include:

- Balancing technical merits of each project or program with economic benefits and goals
- Ensuring that projects and programs undergo proper research, development, planning, review, and authorization by senior management before resource commitment and expenditure
- Ensuring proper decision points for approving further funds, as project details evolve.

The Central Review Committee makes recommendations regarding changes to the proposed work scope to meet the challenges to the overall capital budget.

F. Other System Planning Functional Roles

Other key functional roles provided to AIC by the planning groups provide underpinnings of the Capacity Planning Process. These duties shape the overall capability of the system with wide ranging implications on the design of system expansion, replacement alternatives, operational actions, and equipment standards.

1. Development of Capacity Planning Criteria

System planning maintains system planning criteria through assessments of new developments in system equipment technology and system configuration changes, *e.g.,* solid dielectric high voltage cable technology, DER inverter-based generation, and distribution circuit automation. Criteria are then updated in the planning guideline, as necessary. AIC's distribution planning criteria allow peak feeder loading up to 100 percent of normal capacity without violating voltage criteria. The criteria require that feeders have adequate ties available so that in case of a mainline feeder failure the forecast peak loads can be transferred to other circuits. Distribution substation planning criteria requires that substations have feeder tie capacity to permit load transfers among area substations. Many, but not all, of AIC's substations have redundant sources and buses, requiring the Operations Department to use feeder ties, emergency feeders, mobile substations, mobile generators, and even automatic load shedding to avoid cable and conductor damage for extended transformer overload conditions.

2. Development of Equipment Ratings

All components of the system are expected to be in-service and operating properly under normal operating conditions. Normal equipment ratings apply, and it is expected that the equipment can safely operate at this rating continuously or meet normal load cycling duties without experiencing any loss of asset life beyond normal expectations.

During non-normal or emergency conditions, one or more system components may be considered out-of-service. Emergency equipment ratings may then apply, and it is expected that the equipment can operate safely at this rating for a limited amount of time subject to some acceptable loss-of-life beyond normal expectations. The short-term emergency rating is the peak load level that equipment can accommodate during an outage that is expected to persist less than 24 hours. Acceptable loss-of-life during a short-term outage is not greater than 2.5 percent of the total loss-of-life beyond normal expectations during the 24-hour period. AIC may transfer load by switching, installing mobile or spare transformers, or by dispatching distributed or mobile generation to prevent damaging equipment.

Planning guidelines specify limits for allowable emergency rating usage durations predicated on the size of equipment, *e.g.,* transformer power rating, and other factors such as the number of customers served. AIC guidelines prescribe proactive operating measures to shift load, operate capacitor banks, or other operating actions to avoid equipment loading within the emergency ratings of equipment; however, once these options are exhausted, AIC operates equipment to the maximum rating, and reserves load shedding as a last resort mitigation measure.

G. Reliability Project and Program Planning

AIC Reliability engineers develop reliability programs to improve SAIFI, CAIFI, CAIDI, and SAIDI, to reduce outages and the effect of outages on customers. The engineers use a cost versus reliability benefit ratio justification process for determining the most cost beneficial programs to prioritize the application of reliability programs for specific circuits, and for determining when the cost of the program becomes too high when reliability benefits diminish. AIC's capital distribution circuit automation program (an IIP initiative, discussed in Chapter V) is designed to automate circuit sectionalizing and restoration, which reduces the impact of outages by reducing the number of customers interrupted (CI) and customer minutes of interruption (CMI).

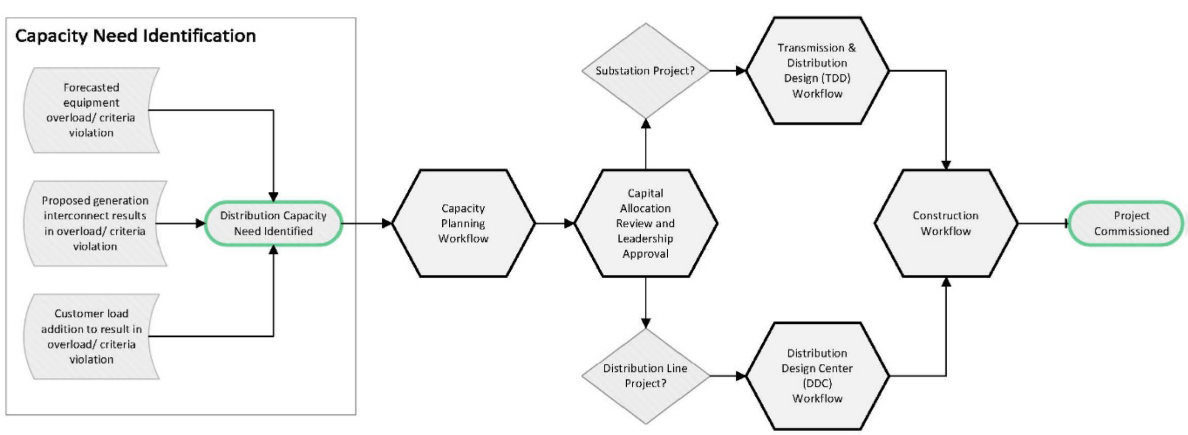
AIC reliability engineers determine the benefits of applying a program or a mix of programs, such as installing mid-circuit reclosers or distribution circuit automation to a feeder with low reliability. Cost effectiveness forecasting methods include estimated avoided interruptions based on historical feeder reliability, and the estimated number of avoided customer interruptions (CI) and customer minutes of interruption (CMI) expected by the application of a program remedy or by a mix of program applications.

H. Planning Examples

Capacity planners identify capacity projects based on load studies and forecasts. These projects may provide solutions from local capacity issues involving a conductor or a component to a capacity issue over a larger geographic area, or entire substation. AIC's capacity planning process depends on the equipment encompassed and on cost, as described by planning process steps indicated in the following figure.

For proposed local area capacity planning projects under $100,000, a planner develops proposed solutions and project diagrams. The Area Operations Manager reviews and approves a proposed solution description and one-line drawings and then forwards the proposal to the Distribution Design Center (DDC) 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, proposed capacity projects may proceed to a project review meeting, where the portfolio of proposed investments during the annual planning cycle is discussed, or directly to the Planning Manager. Again, depending on cost threshold limits, the proposed project is forwarded to the DDC to prepare the project. If applicable, for costs exceeding the capital allocation threshold, the project is forwarded to the CPOC within which the proposed project undergoes the formal authorization if required by Ameren Illinois leadership.

Capacity Planning Process



The following scenarios provide brief descriptions of how AIC plans solutions to capacity relief issues. The hypothetical costs below represent Liberty assumptions.

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

Assuming the solutions, such as increasing the size of conductors, installing a new circuit, or conversion of the 4kv circuit to 12kv, 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 planning group proposes the upgrade solution, the Area Operating Manager reviews and approves the project description and one line map and then submits the project for review and approval, before being finally reviewed and authorized and AIC leadership.

Scenario No. 2: AIC 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, addition of a second transformer, or addition of a new substation, hypothetically costs $500,000, the capacity planning, transmission planning, and substation engineering groups would work together to develop possible solutions. The project determined would undergo challenge by internal planning review and the Area Operating Manager, before submission to AIC leadership for authorization.

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

Assuming the solution, such as installing a larger transformer, addition of a second transformer, or addition of a new substation hypothetically costs about $500,000, the capacity planning, substation engineering groups would work together to develop possible solutions. After engineering, input from the industrial customer on solutions follows. Then, the best solution is submitted to AIC leadership for review, challenge, and approval.

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

Assuming the solution hypothetically costs about $90,000, proposed solutions such as alternative feeder extension, alternative phase extension, or shifting of normally open tie points between two feeders, would undergo review by the internal planning challenge and by the Area Operating Manager, then sent to the DDC.

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

AIC would follow the procedures defined in IL Administrative Code Part 466 and Part 467, respectively, on receiving an application for interconnection of a cogeneration facility, capacity planning would evaluate the intended operation of the energy recovery system, its effect on the distribution grid, its effect upon system protection, *i.e.*, available fault current and coordination of protection elements, and the effect of interconnected generation upon system reliability and dispatchability. Engineers would study the effects of the additional generation both during minimum and maximum circuit loads and determine upgrades, if any, required to interconnect the customer.

XI. Database

A. Overview

We created a data baseline, or database, for AIC 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 AIC and ComEd databases we created 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 data request that asked AIC to complete a Liberty-designed Excel-based data template eliciting a variety of distribution system information. Liberty subsequently issued additional data requests, some multi-part, and 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. AIC 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:

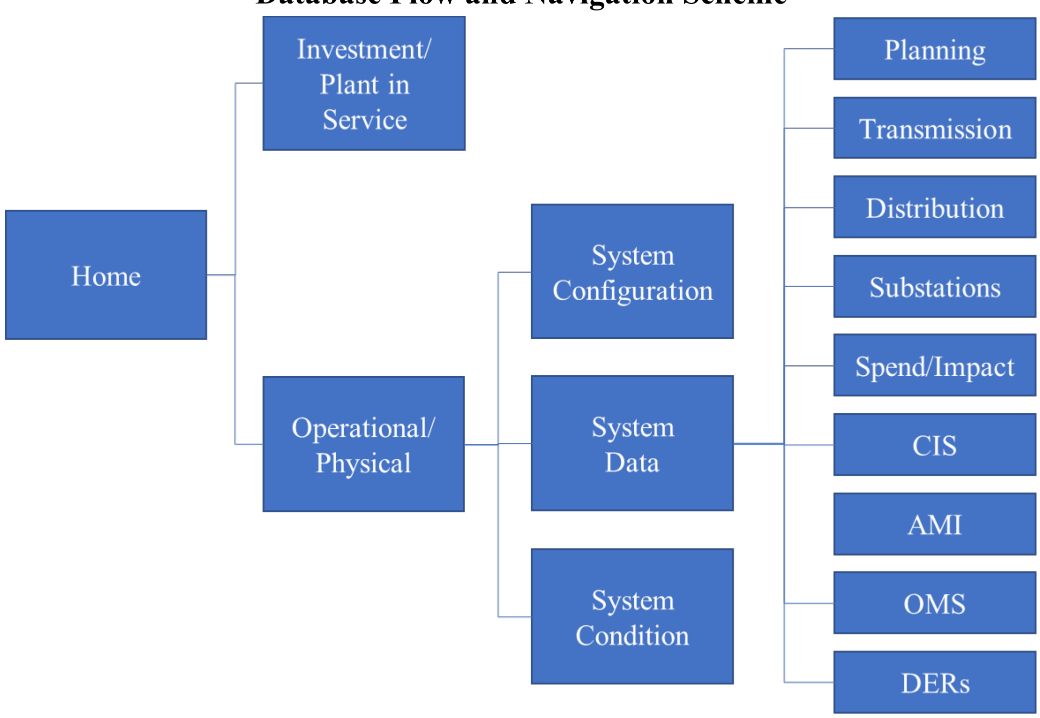
- Collecting spreadsheet templates
- Identifying relevant data from Staff responses to incorporate into the database
- Adjusting data to accurately reflect the difference between "no data" and an entry of zero where applicable
- Capturing text notes and data source explanations
- Turning each table into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

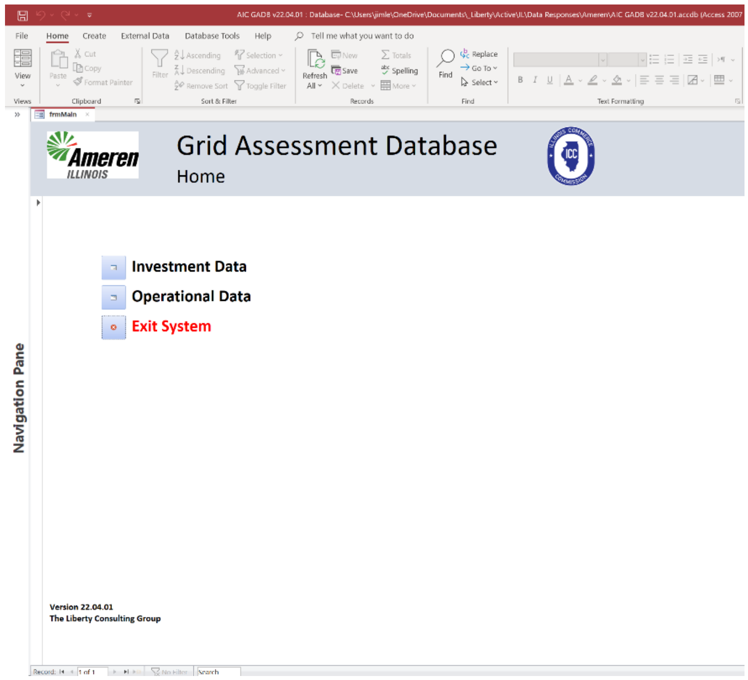
Database Table and Record Summary

Category	Name	Source	Records
AMI	tblAMI	AMI.XLS	153
CIS	tblCIS	Customer Information Systems.XLS	720
DER	tblDER	DES-DER.XLS	810
Distribution Circuits	tblDistCirc	Dist Circuits.XLS	1,656
Investment	tblInvestment	EB 1.01 Attach 1.XLS	325
Investment	tblInvestmentPIS	EB 1.01 Attach 3.XLS	195
OMS	tblOMSCalls	OMS.XLS	36
OMS	tblOMSInitialOutage	OMS.XLS	99
Planning	tblPlanning	Planning.XLS	504
Substations	tblSubstCount	Substations.XLS	432
Substations	tblSubstFieldOpAreas	Substations.XLS	36
Substations	tblSubstInstalls	Substations.XLS	36
System Condition	tblSysCondBasics	System Condition.XLS	855
System Condition	tblSysCondBreakerEventsVoltage	System Condition.XLS	216
System Condition	tblSysCondBreakerReplace	System Condition.XLS	75
System Condition	tblSysCondBreakersInstalled	System Condition.XLS	270
System Condition	tblSysCondMainlineCableMiles	System Condition.XLS	107
System Condition	tblSysCondOHDistMiles	System Condition.XLS	96
System Condition	tblSysCondOHSubtransMiles	System Condition.XLS	71
System Condition	tblSysCondRecloserAction	System Condition.XLS	108
System Condition	tblSysCondRecloserEvents	System Condition.XLS	72
System Condition	tblSysCondRecloserVoltage	System Condition.XLS	25
System Condition	tblSysCondSubstBreakerAge	System Condition.XLS	432
System Condition	tblSysCondSubstBreakerEvents	System Condition.XLS	108
System Condition	tblSysCondSubstInspections	System Condition.XLS	636
System Condition	tblSysCondSubstVipers	System Condition.XLS	14
System Condition	tblSysCondSubstVipersInstalled	System Condition.XLS	45
System Condition	tblSysCondTransformerAge	System Condition.XLS	705
System Condition	tblSysCondTransformerFailures	System Condition.XLS	24
System Condition	tblSysCondUGSubtransMiles	System Condition.XLS	31
System Condition	tblSysCondURDCableMiles	System Condition.XLS	66
System Condition	tblSysCondWoodPoleAge	System Condition.XLS	133
System Configuration	tblSysConfig	System Configuration.XLS	315
Transmission & Subtransmission Circuits	tblTranSubtranCircuits	Tran-Sub-T Circuits.XLS	576
Spend-Impact by Region	tblSpend-Impact	Value Spend Tab.XLS	549
Total Records			**10,531**

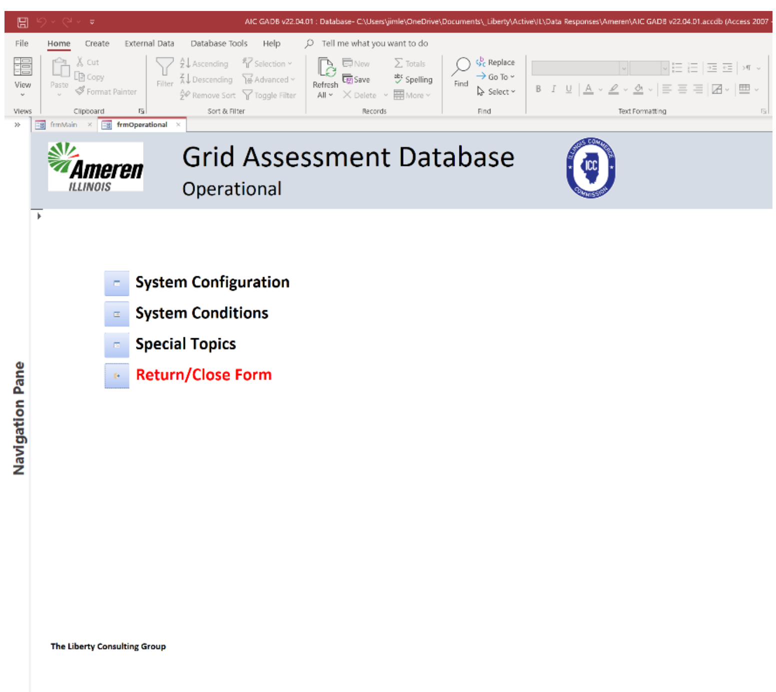
Interface

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.

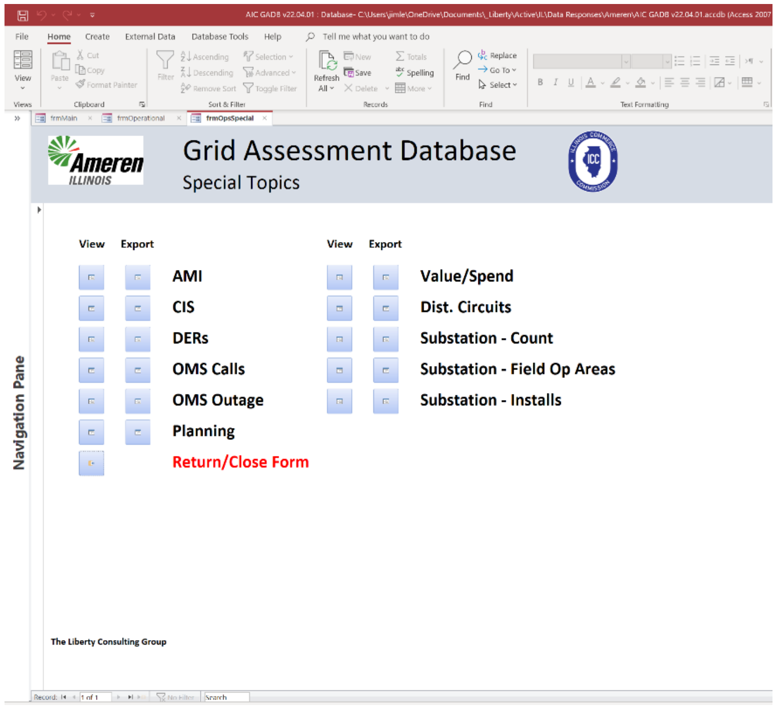
Database Screenshot – Home Page



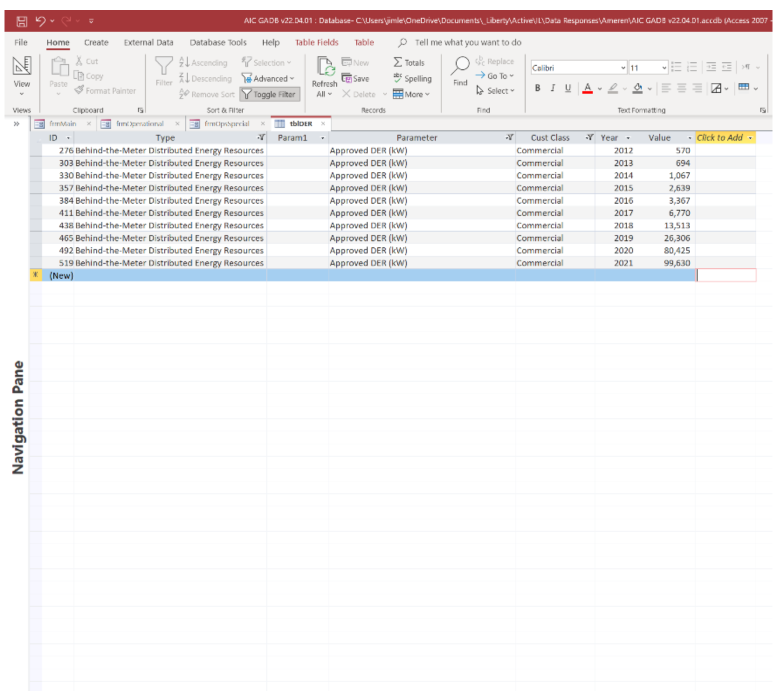
Database Screenshot – Quick Links



Database Screenshot – Querying Capabilities



Database Screenshot – Sample Query Output



ID	Type	Param1	Parameter	Cust Class	Year	Value
276	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2012	570
303	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2013	694
330	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2014	1,067
357	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2015	2,639
384	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2016	3,367
411	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2017	6,770
438	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2018	13,513
465	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2019	26,306
492	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2020	80,425
519	Behind-the-Meter Distributed Energy Resources		Approved DER (kW)	Commercial	2021	99,630
(New)						

Appendix A: List of Acronyms

Acronym	Full Name
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ATO	Automatic Throw Over
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CapEx	Capital Expenditures
CERT	Customers Exceeding Reliability Targets
CI	Customer Interruptions
CM	Corrective Maintenance
CMI	Customer Minutes of Interruption
DER	Distributed Energy Resource
EIMA	Energy Infrastructure Modernization Act
Feeder	Distribution circuit, primary voltage <15kV
FERC	Federal Energy Regulatory Committee
HAN	Home Area Network
I	Interruption (Outage Event)
IC	Interconnecting Customer
ICC	Illinois Commerce Commission
IEEE	Institute of Electrical and Electronic Engineers
IIP	Infrastructure Investment Plan
IOC	Integrated Operations Center
IS	Information Security
IT	Information Technology
IVR	Interactive Voice Response
kV	Kilovolts (x1000)
kWh	Kilowatt Hour
MAP	Modernization Action Plan
MAP-P	Modernization Action Plan – Pricing
MDMS	Meter Data Management System
MED	Major Event Day
MISO	Midwest Independent System Operator
MPR	Microprocessor based relaying subsystems or assets

MVA	Mega Volt Amperes (units of energy capacity)
MW	Mega Watt (units of power capacity)
N-1	Underlying system design basis designation, for capability to deliver with a single element loss, out of total (N) elements in system
NERC	North American Electric Reliability Council
NIST	National Institute of Standards and Technology
NOC	Network Operations Center
O&M	Operating and Maintenance
OH	Overhead Construction Class subsystems or assets
OMS	Outage Management System
OTA	Over-the-Air
PM	Preventive Maintenance
PMO	Project Management Office
PTR	Peak Time Rewards
PTS	Peak-time Savings
RFP	Request for Proposal
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGAC	Smart Grid Advisory Council
Sub	Substation facility, subsystem, or asset class
T	Transmission subsystem or asset class
UFE	Unaccounted For Energy
UG	Underground Construction Class subsystems or assets
URD	Underground Residential Direct Burial Class subsystems or assets
Veg Mgt	Vegetation Management
Volt-VAR	Volt-Amperes Reactive
WO	Work Order
WPC	Worst Performing Circuit