STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on July 15, 2021

COMMISSIONERS PRESENT:

John B. Howard, Chair
Diane X. Burman
Tracey A. Edwards
David J. Valesky
John B. Maggiore
Rory M. Christian

CASE 20-E-0618 - In the Matter of December 15, 2020 Electric Emergency Response Plan Review (2021 Plan).

ORDER APPROVING, SUBJECT TO MODIFICATIONS, THE AMENDED ELECTRIC EMERGENCY RESPONSE PLANS

(Issued and Effective July 15, 2021)

BY THE COMMISSION:

INTRODUCTION

Each Investor-owned electric utility under the Commission's jurisdiction is required to develop, update, and file with the Commission a detailed Emergency Response Plan (ERP), detailing the utility's response plans for emergencies that comply with Section 66 of the Public Service Law (PSL) and Title 16 New York Code, Rules, and Regulations (NYCRR) Part 105.[1] The electric utility's ERPs contain essential processes and

[1] The investor-owned electric utilities are Consolidated Edison Company of New York, Inc. (Con Edison), Central Hudson Gas & Electric Corporation (Central Hudson), New York State Electric & Gas Corporation (NYSEG), Niagara Mohawk Power Corporation, d/b/a National Grid (National Grid), Rochester Gas and Electric Corporation (RG&E), and Orange & Rockland Utilities, Inc. (Orange & Rockland or O&R).

procedures necessary to engage and respond to a wide array of emergencies. External and internal communication practices, personnel roles and responsibilities, and procedures implemented before, during, and following emergencies, represent just a fraction of the numerous measures that are required to be in each electric utility's ERP.

This year's review of utility ERPs reflects the actions taken following Tropical Storm Isaias, including outcomes from the notice of apparent violations and immediate corrective action letters sent to Con Edison, Orange & Rockland, and Central Hudson, as well as the immediate corrective action letters sent to NYSEG, RG&E, National Grid, and PSEG LI on August 19, 2020 (collectively, Corrective Action Letters).[2] The ERPs also incorporate findings from the Interim Investigation Report on Tropical Storm Isaias (Report) issued on November 19, 2020.[3] Many of the improvements made to the emergency response plans discussed in this Order relate to preventing inadequate storm responses, such as that of Con Edison, Orange & Rockland, Central Hudson, and PSEG LI during Tropical Storm Isaias. Several modifications were also made to all ERPs, including PSEG

[2] Case 20-E-0586, supra, Notice of Apparent Violation Related to Tropical Storm Isaias and Direction of Prompt Remedial Action (filed August 19, 2020)(NOAV) and Case 20-E-0586, supra, CEO Rhodes Letter Re: Tropical Storm Isaias After-Action Responses (filed August 19, 2020) (Corrective Action Letters).

[3] Tropical Storm Isaias struck on August 4, 2020, significantly impacting Long Island, New York City, and several counties in the mid and lower Hudson Valley. The storm's impacts resulted in peak outages of approximately one million. On August 5, 2020, Governor Andrew M. Cuomo directed the Department of Public Service (Department or DPS) to investigate New York State's major electric utilities' (utilities) following the slow and inadequate response of certain electric utilities to Tropical Storm Isaias.

LI, to take advantage of best practices as well as to provide consistency across the ERPs.[4]

The Commission, pursuant to PSL §66(21), has a statutory obligation to review each investor-owned electric utility's emergency plans annually and 16 NYCRR §105.5 also requires annual review and approval of emergency plans which are designed to ensure improved preparedness for future outage events. PSL §66(21) requires all electric ERPs to be updated annually and submitted to the Commission for approval on, or before, December 15 of each year. Accordingly, the ERPs, having been reviewed by the Commission are approved with the modifications discussed herein.

BACKGROUND

On August 4, 2020, Tropical Storm Isaias made landfall on the east coast, continued tracking north and passing through eastern New York State. The storm caused severe and extensive damage throughout the Mid-Hudson, New York City, and Long Island Regions.[5] PSEG LI experienced the highest winds, which included recorded gusts between 70-78 miles per hour (mph). Gusts up to 70 mph were reported in the service territory of Con Edison, while Central Hudson, NYSEG, and O&R service territories experienced 45-60 mph gusts. The storm caused widespread damage to overhead electric infrastructure, leaving significant numbers of New Yorkers without power. Peak outages in New York State

[4] The PSEG LI ERP review followed a parallel process to the IOUs under Matter 20-02608, In the Matter of the December 15, 2020 Emergency Response Plan of the Long Island Power Authority and PSEG Long Island (2021 Plan) but is not subject to this Order.

[5] The damage in National Grid's Capital Region service area was not as severe. National Grid had a peak of approximately 35,000 customer outages that were restored in less than 36 hours.

due to Tropical Storm Isaias reached approximately one million customers, and roughly 1.5 million New York customers experienced power outages during this event. On August 9, 2020, 90 percent of the utility customers who had lost power had been restored, with full restoration occurring on August 12.

The 16 NYCRR Part 105 storm reports filed by each utility, as required by the Department's regulations, identified approximate peak outages of 380,000[6] for PSEG LI, 290,000 for Con Edison, 138,000 for Orange & Rockland, 110,000 for Central Hudson, and 95,000 for NYSEG. The reports also noted total customer impacts of approximately 645,000 for PSEG LI, 330,000 for Con Edison, 189,000 for O&R, 116,000 for Central Hudson, and 183,000 for NYSEG.[7] Approximately 90 percent of customers in the PSEG LI service territory were restored on August 10. PSEG LI restored all customers on August 12. Ninety percent of Con Edison customers were restored by August 9 and all customers were fully restored by August 12. Orange & Rockland restored 90 percent of its customers the morning of August 8, with full restoration on August 11. Central Hudson had 90 percent of customers restored by August 7 and fully restored all customers impacted by the storm by the evening of August 8. The majority of outages experienced by NYSEG were in its Brewster Division, which serves customers in Dutchess, Putnam, and Westchester Counties. By 5:00 pm on August 8, more than 90 percent of customers in NYSEG's Brewster Division were restored with full restoration just after 10:00 am on August 10.

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[6] The accuracy of this figure cannot be verified due to the issues PSEG LI had with its OMS.

[7] See, Matter 20-01633, In the Matter of DPS Investigation into the Utilities Preparation and Response to August 2020 Tropical Storm Isaias and Resulting Electric Power Outages, Part 105 Reports.

As a result of the extended restoration, each utility was directed in the Corrective Action Letters to undertake immediate action to add crewing capacity via retainer contracts as well as develop plans to secure utility crews in addition to private contractor and mutual assistance beyond the North Atlantic Mutual Assistance Group (NAMAG) process. In addition, the utilities were directed to conduct stress tests on their respective information technology systems, refine coordination plans with municipalities tailored to each county, e.g., road clearing and local liaisons, and to update Life Support Equipment and critical infrastructure lists to remove or add customers as necessary. Each of these requirements are addressed in the ERPs before the Commission.

NOTICE OF PROPOSED RULE MAKING

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), a Notice of Proposed Rulemaking was published in the State Register on February 3, 2021 [SAPA No. 20-E-0618SP1]. The time for submission of comments pursuant to the Notice expired on April 5, 2021. No comments were received.

DISCUSSION

A thorough review was performed for each of the utility's electric emergency response plans filed in December 2020 and those refiled in June 2021. Department of Public Service staff (Staff) had numerous meetings, conference calls, and e-mail exchanges with each electric utility to attempt to resolve areas where additional information was necessary. As a result of this process, each utility filed an amended emergency response plan in June 2021 that addressed either in whole or in part, modifications discussed during the interactions with

Staff. The following sections summarize key areas that were reviewed and modified to enable appropriate responses.

Resource Acquisition and Mutual Assistance

The ability to effectively restore power in a timely manner after any storm event depends on how quickly electric infrastructure such as poles and wires can be repaired. The time it takes to repair electric infrastructure is dependent on the number of internal and external line resources a utility has available. When an electric utility has service outages resulting from a minor storm event, it normally relies on its own resources, such as internal line workers and on-property contractors to restore service. During larger storm events, the utility typically will secure third party contractors that supply line workers and restoration equipment or other skilled workers such as tree crews and damage assessors. The standard method to track and report resources is Full-Time Equivalents, or FTEs.

When a utility's total internal resources and on-property contractor resources are not expected to or do not meet the estimated resources needed to restore service, the utility will then contact external contractor resources and request resources through the North Atlantic Mutual Assistance Group (NAMAG). Utilities also have agreements with multiple contractor resources and have contact lists to expedite securing third-party contractor line, service, and tree resources. In compliance with the Corrective Action Letters directing that the utilities immediately begin the process of securing additional resources in addition to private contractor and mutual assistance provided by the NAMAG before and after storms, the utilities immediately began the process of soliciting externally to augment their respective crewing levels, beyond the NAMAG

process, through extensive canvassing to identify available resources and to enter into contractor retainer contracts and right of first refusal agreements. Currently, the utilities either have contracts or agreements in place, are in negotiations with third parties, have contracts or agreements pending resolution of cost recovery, e.g., rate cases, or are reviewing contractor proposals to comply with the Corrective Action Letter's direction to secure resources in place to expand their access to resources when needed. Through these endeavors, the utilities are positioned to leverage additional resources in future outage events and have done so on numerous occasions, since Tropical Storm Isaias Corrective Action Letters were issued. To that end, we direct the utilities to continue this process through execution of these contracts and/or agreements. It is exceedingly important for the utilities to exhaust every option available to them in order to obtain the supplementary resources needed to restore customers as rapidly and safely as possible.

Estimated Times of Restoration

The Estimated Time of Restoration (ETR) is the approximate date and time when the utility expects service will be restored after a power outage. Customers depend on ETRs to make health and safety decisions, including the need for alternative accommodations. Therefore, ETRs must be timely, accurate, and widely accessible. In August 2013, the Commission adopted ETR Protocols to help ensure that ETRs meet these three essential requirements.[8] Last year, ETR Protocols were revised

[8] Case 13-E-0198, In the Matter of 2013 Electric Emergency Response Plan Review, Order Approving Electric Emergency Plans (issued August 16, 2013).

and strengthened based on recommendations from the 2018 Winter and Spring Storm Report.[9]

To balance the customer's need for information with available damage information and available crews, regional and local ETRs apply to 95 percent of customers instead of 90 percent. During Tropical Storm Isaias, customers and government officials were misinformed as a result of inaccurate ETRs, untimely issuance of revised ETRs, or the lack of clarity on who was covered by the ETR. As a result, customers and public officials were frustrated by the inaccurate, inconsistent, and insufficient messaging.

The ETR Protocols clearly outline extended time requirements for issuing local ETRs to enable utilities to provide more detailed and targeted information. All of the plans now identify individuals responsible for developing, issuing, and revising ETRs. It is imperative that utilities utilize all means of communication to inform the customers and government officials of ETR changes, including proactively reaching out to customers affected by changes and modifying their websites.

Coordinating with Counties and Municipalities

Following major storms, counties, municipalities, and utilities have a make-safe period that focuses on the elimination of hazards to the public. Public hazards include exposure to potential shock risks, which are hazards that can trap residents in their homes and can prevent emergency resources from responding to requests for assistance or fires.

[9] Case 19-M-0285, In the Matter of Utility Preparation and Response to Power Outages During the March 2018 Winter and Spring Storms, 2018 Winter and Spring Storms Investigation Report (filed April 18, 2019)(Storm Report).

Strong and collaborative communications are critical when coordinating these efforts to develop daily work plans.

Additionally, regional municipal calls provide a venue for more detailed discussion of the municipalities' priorities and the presentation of updated information to the municipalities that is not available publicly. There have also been improvements in how utilities and municipalities interact, such as using virtual communications and through the use of municipal dashboards where municipalities can go online to report hazardous conditions, outages, blocked roads, and to track outages in their areas.

This information can also be obtained through utility liaisons, who may be co-located in municipal command centers, county EOCs or available around the clock to the municipalities by telephone. The utilities, however, need to understand that liaisons are only as good as the information that is provided to them. The ERPs contain language that acknowledges municipalities expect their liaisons to do more than reiterate publicly available information, e.g., locations and number of crews, which circuits are being worked, and the ETR status of their residents and/or constituents. Lastly, the ERPs include additional language for the utilities to request input from the counties in their service territories on dry ice distribution locations, however if counties are unresponsive, the utilities will still take action to ensure that customers get dry ice and will endeavor to accommodate reasonable requests to strategically locate distribution sites based on customer impacts.

Testing Critical Information Technology Systems

Customer reported outages are key to identifying the full impact of a storm event on an electric system after a major

outage event. Therefore, outage reports from multiple sources, including the call center, Interactive Voice Response (IVR), utility website, and text messaging, are electronically posted to outage management systems (OMS) which are core applications used by utilities to manage outage events. OMS systems process reported customer outage information received through various means, predict outages to capture the full extent of customers impacted, create, prioritize, and manage jobs, and interface with various applications to provide consistent and updated outage information to utility personnel and the public during normal and emergency operations.

Two months prior to Tropical Storm Isaias, PSEG LI had gone into production with an updated version of its OMS without adequately performing realistic stress testing on the new version. Shortly after Tropical Storm Isaias hit its service territory, various failures in the OMS were identified, causing significant challenges not only for the utility but, more importantly, for the public. PSEG LI's OMS suffered a catastrophic failure that led to the Company's inability to provide accurate outage and job numbers, locations of reported outages, ETR information, as well as efficient and effective dispatching of resources.

As a result of the issues experienced by PSEG LI, each electric utility was required to stress test its respective OMS systems more frequently using more stringent parameters including, as part of the corrective actions following Tropical Storm Isaias, an outage impacting 90% or more of customers in the Company's service territory over a 24-hour period. These conditions will ensure the testing is in line with a realistic outage event and that the OMS will perform adequately in a major outage event.

To ensure this practice continues, the ERPs now include provisions that require OMS testing under the parameters listed above. The tests will be performed semi-annually with the detailed results provided to the Director of the Office of Resilience and Emergency Preparedness following the completion of each test. In addition, reporting requirements have been established that require reporting of detailed test results, as well as require disclosure of interim measures the utilities will use should the OMS stress test fail, until such time as permanent resolutions have been implemented. These measures will ensure stress testing processes and parameters are consistent, better defined and provide for worse case scenarios, including increased real-time monitoring of the systems during major outage events, and verifying the interaction with automated inputs when the system is experiencing high usage. They also provide a communication strategy to address multiple scenarios concerning failure of critical information technology (IT) systems.

Additionally, if a utility OMS system fails a test, the utility is required to retest, after taking corrective actions, to ensure that the failure is corrected. A failed test does not count towards the semi-annual requirement. Each electric utility ERP also identifies how Advanced Metering Infrastructure (AMI) data will be used to improve the accuracy of its OMS. It is expected that additional automated processes will continue to be developed and integrated to improve storm response as AMI continues to be deployed by the utilities.

Information Technology

The utilities' websites, and any event-specific information pages, are two of the primary means used by utilities to inform customers during emergencies. When

reviewing the many communication channels used to provide information to customers, e.g., press releases, social media posts, Interactive Voice Response (IVR) messages, etc., the utilities routinely direct customers to go to their website to gather more information. Therefore, the ERPs contain language that the utility website is required to be available around the clock. During storms, the information on the utilities' outage maps must be updated continuously at the typical cycle (e.g., every 15 minutes) and must be updated at least hourly, so to provide customers with information that is timely and accurate. If critical repairs and/or maintenance must be done, such activities will occur after 10:00 p.m. or before 6:00 a.m. to avoid any downtime and/or disruption of availability during the remaining time periods. In addition, all non-critical maintenance is deferred until all customer outages have been restored, which is currently an industry best practice.

We cannot stress enough the need for critical systems to be operating properly at all times. Therefore, the Commission finds that it is imperative that as soon as a utility website or underlying data sources go down, it reasonable to require that the utilities notify on-call IT personnel expeditiously and without delay. IT personnel will work to resolve the issue and will provide updates on corrective action regularly and/or notify third party vendors in addition to facilitating any interactions between the vendors the utility's IT group.

When customer facing applications are experiencing a technical issue, the ERPs indicate the title of the employee responsible for directing that such notice be posted, e.g., message banner, on the main website homepage and the outage map, as appropriate, providing customers the details and necessary steps for reporting outages and obtaining other event-related

information. This notice will also be used to communicate if system maintenance is underway and, if so, provide status updates on such as well as if the outage map is unavailable due to other issues, such as data quality concerns. The notices must provide outage counts and ETRs. In addition, the electric utilities also use social media to inform customers when these issues exist.

Furthermore, the ERPs designate the title of the employee responsible for stricter monitoring and maintenance of critical systems to ensure continuous access to the important information contained in those systems. These enhanced measures provide the utilities higher visibility and responsibility for making certain the critical information technology systems are properly maintained, but more importantly, diligently monitored so to identify issues quickly and be in a better position to ameliorate those issues effectively.

Alternate Processes

Utilities are increasingly dependent on IT and communications systems as critical tools to assist in their operations and emergency response efforts. While these systems have resulted in efficiencies and better tools for these efforts, the IT systems are vulnerable to being unavailable or operating in a limited capacity during major events. As a result, the ERPs recognize and reflect the need for alternate (manual) processes to complete tasks when primary applications fail (IT software, field tablets, communications links, etc.). This applies to activities such as damage assessment, wires down, work order dispatching, and retrieving updates from line crews in the field. Pursuant to PSL Section 66 and 16 NYCRR Part 105, each electric utility is required to conduct exercises to test the capabilities of employees and the overall

preparedness of the utility for responding to events. Accordingly, the ERPs also include language requiring the utilities to periodically practice their personnel performing these alternate processes during exercises.

After-Action Process

The after-action process is an integral evaluation tool post event with the goal of improving utilities' performance. Meetings are generally attended by the organizations that participated in the event. These organizations work together to identify issues experienced and devise corrective actions, e.g., what went wrong, what can be done to correct issues going forward, and activities that worked well. To be effective, the After-Action Reviews (AAR) must be conducted shortly following an event to capture information while it is still fresh in everyone's memories.

Each of the ERPs contain an after-action process, however, based on our observations, there was an imbalance between the operational and communications organizations. It is essential that the operational and communications organizations both be substantial contributors in the after-action process to ensure a well-rounded review and identify any issues that may include both organizations.

The amended ERPs now reflect improved processes to perform AARs following events, as well as exercises. Changes were made to give communications groups their own workspace to discuss the event without being overwhelmed by operational considerations. The utilities should foster enhancements to ensure the AARs are comprehensive and capture all pertinent information necessary to prepare and share with stakeholders, reports that not only detail the issues, as well as the measures to be taken to avoid those issues in the future, but also

implementation plans to put those measures into practice. The first step in that undertaking must be to identify the titles responsible for each step of the after-action process including scheduling and conducting meetings, information gathering as well as preparing After-Action/Implementation reports within a prescribed timeline. Assigning ownership in the ERPs for each step of the AARs and the associated deliverables will increase their effectiveness in the future. In addition, the ERPs recognize the need to have more than one meeting, based on the size of the event. For sizeable events, the utilities must, at a minimum, conduct separate meetings to review and evaluate operational and communications performance. In doing so, the utilities will foster a critical review and a more robust After-Action report/Improvement Plan (AAR/IP) that address strengths, opportunities, trends, lessons learned, and recommendations. Furthermore, in order to ensure that the AAR/IP are meaningful and drive real change, they are to be shared with all stakeholders. The ERPs reflect a similar process that applies following utility exercises by having After-Action Meetings scheduled as soon as practical with the involved organizations.

Call Center Staffing and Call Answer Rates

Customers expect and deserve to be connected to a live representative in situations when other technologies, e.g., website, text, e-mail, etc. are not available and/or when a utility's IVR automated system cannot fully assist them. Access to customer service representatives not only gives customers the ability to report outages and emergency situations, but also the opportunity to ascertain specific outage and restoration information. Understaffed call centers lead not only to the utility's failure to meet the call answer rate metric, but also often results in frustrated customers at a time when outage and

restoration information is needed the most, particularly when circumstances arise that prevent customers from reporting outages through other methods.

Each utility's ERP details how the utility will staff its call centers in order to effectively respond to the high volume of callers attempting to speak to a live representative throughout an event. To be clear, call centers must answer 80 percent of these calls within 90 seconds each day of a major outage event. In order to meet this requirement throughout the event, the Commission finds it reasonable to require that the utility implement appropriate staffing levels expeditiously and continuously monitor incoming call volume and abandonment rates to determine if staffing levels must be adjusted or if and when engaging the utility's high-volume call assistance vendor. Undoubtedly, there will be times when the decision must be made to ramp up to a higher staffing level, without much notice, in excess of the minimum staffing numbers provided in the ERPs and the utilities must be positioned to meet these challenges in order to answer 80 percent of calls within 90 seconds. Each utility has implemented the capability for call center representatives to answer calls remotely, therefore, we expect that the utilities will be able to respond more quickly than they were when representatives needed to travel to the call centers.

Language has been added to the ERPs that specifically states the title responsible for attentive monitoring of staffing levels, call volume, and call answer rates to ensure improved preparation for and reactions to high call volume. Thus, informed staffing decisions are made and/or the use of all available tools, e.g. high-volume call answering options, etc., are expeditiously engaged by the utility so customers can reach a call center representative when desired.

Life Support Equipment Customers

Life Support Equipment (LSE) customers are defined in 16 NYCRR §105.4(b)(9) as those customers who require electrically operated equipment to sustain basic life functions. While LSE customers do not receive priority restoration during outage events, they are afforded certain protections when affected by power outages due to their medical vulnerability. In fact, LSE customers' accounts contain a special code and their meters are designated with a medical seal to prevent disconnection.

The Corrective Action Letters required the utilities to update LSE and Critical Infrastructure lists to remove or add customers as necessary within ten days, which the utilities completed. Utilities also successfully completed the addition of LSE customer designations. Removal of the LSE designation from an account, however, is often made difficult by the parameters the utilities must adhere to, e.g., obtain either a death certificate or have the customer or other responsible adult execute a utility-produced form stating the LSE designation is no longer applicable. Nevertheless, the utilities, including PSEG LI, are diligently working to identify individuals and more than two thousand have been removed from the LSE list or are under review. The utilities' ERPs detail how LSE customer information is to be verified and updated semi-annually, at a minimum. In addition, the ERPs include reviewing contact information with LSE customers through all interactions with customer service representatives as well as periodic outreach campaigns.

Due to the vulnerable nature of this customer population, the electric utilities are required to maintain daily direct contact (which for the purposes of the Scorecard

are in turn measured daily for compliance therewith, not over the course of the storm) with all affected LSE customers during major outage events to verify their safety and well-being and these processes are included in the ERPs.[10] To that end, utilities must attempt to contact a minimum of 80 percent of affected LSE customers each day, via personal telephone calls within 12 hours. If the LSE customer is not reached on the first attempt, the utilities must make a second attempt each day within the same 12-hour period. It should be emphasized that these are minimum requirements and the utilities should make additional call attempts to reach this customer population.

Additionally, to be effective, the Commission finds it reasonable to require that the utility should place the calls in appropriate intervals (e.g., at least one hour apart) to increase the chance of reaching the customers by phone. Finally, if, after two call attempts the LSE customer has not been contacted, utilities must either conduct a wellness visit using internal resources or refer to an Emergency Operations Center or other third-party to conduct field wellness checks so that 100 percent of affected LSE customers have either been contacted directly or a wellness check has been performed within 24 hours each day (any prior reference to a different metric is hereby superseded by this Order). Utilities are held to these measures and compliance is required and measured each day (not

[10] Case 13-E-0198, In the Matter of 2013 Electric Emergency Plan Review, Order Approving Electric Emergency Plans, Order Approving Electric Emergency Plans (issued August 16, 2013) p. 18.

measured over the course of the storm) until service has been restored to all LSE customers.[11]

In order for the LSE requirements to be effective and given the dynamics of this customer population, proper record-keeping is essential during events such that no LSE customer is missed. Therefore, the utilities need to dedicate appropriate levels of resources to comply with these essential contact requirements during qualifying events. While the minimum requirement is to make two call attempts to affected LSE customers within 12 hours, utilities are expected to perform more if needed prior to referrals provided time allows. One of the reasons for having the 80 percent requirement by phone is to encourage efficiency and reduce the number of wellness checks that must be made as well as dedicating resources who may be used for other important restoration efforts.

Municipal Calls

Municipal calls are an important tool used by utilities to provide government officials with pertinent information prior to and during major outage events. In addition, municipal calls are intended to provide high-level information to these officials so that they are better positioned to keep constituents better informed about restoration efforts and progress. The calls are designed to be relatively brief, provide information that is not publicly available, and answer specific questions from the participants. Lastly, when circumstances arise, e.g., widespread outages throughout a utility's service territory, municipal calls may

[11] Case 13-E-0140, Proceeding on Motion of the Commission to Consider Utility Emergency Performance Metrics, Order Approving the Scorecard for Use as a Guidance Document to Assess Electric Utility Response to Significant Outages (issued December 23, 2013), p. 26.

diverge into multiple regional calls to meet the needs of the respective regions.

Most utilities currently use operator-assisted vendors to conduct municipal calls and include language in their ERPs to memorialize such practice. With the operated-assisted service, attendance is taken by an operator, which the utility has access to see, saving time during a major outage event; and, the operator presents participants with directions on how to ask questions. According to design, participants that want to ask questions are placed in a queue by the operator and are presented individually by the operator. Finally, operator-assisted calls can be recorded as a quality control measure to track any follow-up directed at the utility.

Con Edison, however, did not engage in this question and answer process during its Westchester municipal calls during Tropical Storm Isaias. Instead, just as during Winter Storms Riley and Quinn, Con Edison continued to conduct its lengthy roll call, thereby giving all participants an opportunity to address the utility. This led to hours long calls where each participant offered comment that consistently centered around the intense frustration among municipal officials over the lack of accurate and transparent communications from Con Edison. Con Edison has since transitioned to using the operator-assisted call and the Commission directs that this practice be continued.

Central Hudson opted to use a virtual platform to conduct its municipal calls rather than through a third party vendor, particularly during the COVID-19 pandemic. This presented yet another tool that accomplishes the same goal as operator-assisted municipal calls, including automatic roll call, muting options to limit distracting background noise as well as the ability of the utility to selectively unmute participants so they may ask questions, and to record the calls.

We find this an acceptable alternative for operator-assisted calls.

Having smaller regional municipal calls ensures that the utilities provide more precise information related to the particular region as well as ensuring a more reasonable number of participants are on the calls. Based on our observations of PSEG LI's successful practice of conducting regional calls centered on impacts to its operating divisions is a best practice. It enables the utility to provide more focused information to a smaller group of participants. As a result, all the ERPs recognize circumstances may exist such that multiple, targeted municipal calls may need to occur.

Calls are effective when utilities are telling municipalities and government officials how they are responding to their requests or question regarding the utilities' restorations efforts, e.g. when implementing a decentralized approach versus a centralized approach, crews may leave an area to respond to a large outage even when small outages remain. Other best practices are including federal officials in the invitations to municipal calls as well as recording all municipal calls as a means to track follow-up items to ensure that all requests and questions are fully addressed after the calls.

Dry Ice

Public Service Law §66 and 16 NYCRR §105.4(b)(9) require the electric utilities to describe the methodology for estimating dry ice needs during an emergency period expected to exceed 48 hours as well as the arrangements for obtaining and distributing dry ice to designated customer groups. In addition, utilities must have communications processes to make

customers aware of the availability and the location, dates, hours and amounts of dry ice to be distributed.

In 2020, there was a national shortage of carbon dioxide, the main component of dry ice, due to the impacts of COVID-19 on manufacturing and transport processes. As a result, during Tropical Storm Isaias, a number of utilities were unable to obtain adequate amounts of dry ice. Their attempts to distribute wet ice instead were accompanied by poor communications, resulting in customer confusion. It was observed that customers and government officials unexpectedly found that the utilities were distributing wet ice rather than dry ice and were often unprepared to transport wet ice, for example, not having a cooler in vehicles to prevent the ice from melting.

It is expected that dry ice will continue to be the primary cooling material provided to customers during outage events. However, there is a benefit to distributing wet ice at times to minimize food and medicine spoilage. The ERPs contain improved practices to distribute both dry and wet ice. The utilities are directed to clearly state to customers when wet ice is to be distributed, so to ensure customers are prepared to transport wet ice. Finally, the inability of a utility to properly order or secure dry ice under normal conditions is not viewed as a supply issue.

Con Edison ERP Action Items

Through this Order, the Commission also identifies certain language in the proposed 2021 Con Edison ERP that represents significant changes from its Approved 2020 ERP. While the Commission finds many of these changes better promote storm preparation and restoration, the Commission takes issue with Con Edison's proposed 2021 ERP Section 4. The Commission

hereby revises the proposed Con Edison 2021 ERP Section 4 as follows (the Con Edison ERP Action Items). These Con Edison ERP Action Items will be further evaluated at the below-noted upcoming collaborative meetings to determine their future need in the next ERP submittal after the chance for additional stakeholder comment.

(1) The following is hereby added to Con Edison's proposed and submitted 2021 ERP language in Section 4.1, Table 4.1A (Incident Classification Definitions/Response Levels) consistent with the prior Con Edison 2020 ERP:

- *Serious classification:* "A level Serious is automatically declared when significant resources from outside the region are requested or normal work is extensively interrupted. May be initiated by a Senior Executive Officer without meeting other criteria."
- *Full Scale classification*: "Automatically declared if Company resources are not adequate to respond. Note: A Full-Scale Incident can be preemptively declared when there is forecast for excessive heat or a major storm to impact/impacting the region."

(2) Con Edison is hereby ordered to file with the Secretary to the Commission, within 30 days of issuance of this Order, a revised Section 4.3 of its 2020 ERP to be incorporated into its 2021 ERP Section 4. Con Edison is directed to better clarify this section's scope to avoid future ambiguity as to its intended purposes. The fully revised plan, reflecting the directives in this Order, shall be filed with the Secretary to the Commission within 30 days of issuance of this Order.

As part of its June filing, Con Edison removed mention of the ONIM, after having included it in the December 15, 2020

filing. The ONIM requires Con Edison to conduct specific notification activities based on the number of customer outages and outage duration as well as includes a structure for the calculation of penalties to be paid by Con Edison in the event of nonperformance.[12] Because the ONIM is a communication protocol and were parts of previously approved plans, we find it appropriate at this time that ONIM the requirements be added back to the ERPs. The ERPs are designed to respond to varying ranges of outage events, including those covered by the ONIM. However, the Department is hereby asked to consider through this Order and report back to the Commission at the below noted forthcoming collaborative meetings, with stakeholder input, whether the ONIM should be eliminated given similar, but not exact, communication requirements in Con Edison's ERP, or be expanded to apply to other utilities.

Items Requiring Further Discussion

While significant progress has been made during this review of the ERPs, there remains more work to be done. New laws and regulations regarding the utilities' restoration and related efforts have either been enacted or are being considered. Once a thorough analysis of these laws and regulations is complete, there will likely be further impacts on the ERPs that must be considered. During our review, many questions have been raised insofar as the metrics used to assess the utilities' performance during outage events. Thus, there is a need to revisit existing metrics to enhance their effectiveness and to determine whether there are other ways to

[12] Case 00-M-0095, et al., Consolidated Edison, Inc., and Northeast Utilities – Merger, Divestiture of Power Plants and Rate Restructuring, Order Approving Outage Notification Incentive Mechanism (issued November 30, 2000).

measure the efficacy of the utilities' storm response and restoration efforts, and/or alternative ways to drive better performance. In addition, it would be beneficial to standardize terminology, general requirements, impact of any future pandemic or pandemic-like events and storm classifications across utilities and discuss whether improvements are needed in the ETR Protocol. While the ERPs (and the ONIM) reflect the existing tools, these important questions and topics should be explored through collaborative discussions among Staff, the utilities, and other stakeholders. These "collaborative meetings" are to be initiated by no later than September 30, 2021, to enable the outcome of the sessions to be incorporated into the next round of ERP submittals in December 2021.

CONCLUSION

It is important to note that just because language exists within the ERPs for the topics discussed herein, actions speak louder than words. That is to say, an ERP may contain detailed processes and identify who is responsible for ensuring the processes are carried out, but utilities need to execute those processes to be successful. The amended ERPs are the result of multiple review cycles and reflect compliance with and expansion of the corrective actions identified in the August 19, 2020 letters sent to the utilities. The ERPs lay the groundwork for effective preparation, response, communication, and restoration for customers impacted by the ever-increasing volume of severe weather experienced in New York State.

Furthermore, additional improvements have been made to the ERPs after identifying best practices such as transitioning to smaller regional municipal calls, increasing coordination with counties regarding dry ice distribution locations, including alternate processes should critical IT systems fail as

well as including those processes in trainings and exercises, identification of specific roles and responsibilities to ensure greater accountability in monitoring call center staffing levels to comply with the 80 percent of calls answered within 90 seconds; monitoring expiring ETRs; and, improving ETR communications with customers and government officials, etc. Collectively, the amendments made to the ERPs this year will improve the customer experience during major outage events, improve their response to outage events by having more resources available to restore power, provide more honest and accurate information to customers and government officials, knowing that continuous improvement is not only expected by the Commission but also by the customers they serve. Lastly, the collaborative meetings will provide all parties an opportunity to offer input into the important topics identified herein requiring further discussion as well as clarification of expectations and/or resolution of differences aimed at improving utility consistency, where applicable, and performance in the future.

The Commission orders:

1. The amended emergency response plans filed the week of June 14, 2021, by Consolidated Edison Company of New York, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange & Rockland Utilities, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, as further amended as directed in the body of this Order, are approved.

2. Consolidated Edison Company of New York, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange & Rockland Utilities, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation are directed to file with the Secretary to the Commission, within 30 days of issuance of this

Order, amended emergency response plans that implement and comply with the amended emergency response plans filed the week of June 14, 2021, and as further modified as directed in the body of this Order.

3. Consolidated Edison Company of New York, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange & Rockland Utilities, Inc., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation are directed to participate in collaborative meetings, which will be noticed and initiated by Department of Public Service Staff to address the ERP and ONIM issues across all utilities as directed in the body of this Order, no later than September 30, 2021.

4. In the Secretary's sole discretion, the deadlines set forth in this Order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

5. This proceeding is continued.

By the Commission,

(SIGNED) MICHELLE L. PHILLIPS
Secretary