STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 141

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Smart Grid Technology Plans Pursuant to Commission Rule R8-60.1(c)	) ORDER APPROVING SMART GRID) TECHNOLOGY PLANS, DECLINING) TO SCHEDULE A HEARING, AND) REQUESTING COMMENTS ON RULE) REVISIONS

BY THE COMMISSION: On October 1, 2014, in compliance with Commission Rule R8-60.1, Duke Energy Progress, LLC (DEP); Duke Energy Carolinas, LLC (DEC); and Dominion North Carolina Power (Dominion) filed smart grid technology plans (SGTPs). After several requests for extensions of time for the filing of comments, which the Commission granted, comments were filed on January 9, 2015, by the Public Staff and jointly by the North Carolina Sustainable Energy Association (NCSEA) and the Environmental Defense Fund (EDF). On January 29, 2015, reply comments were filed jointly by DEP and DEC (Duke), by Dominion, and jointly by NCSEA and EDF (NCSEA/EDF).

On October 1, 2015, DEP and DEC filed updates to their SGTPs as required by Commission Rule R8-60.1(b). On the same date, Dominion submitted a letter stating that it had not made any significant revisions to its initial SGTP and that it would continue to implement its initial plan.

Background

By Orders dated April 11, 2012, and May 6, 2013, in Docket No. E-100, Sub 126, the Commission adopted rules requiring electric utilities that file integrated resource plans (IRPs) to include in those IRPs information on how planned "smart grid" deployment would impact the utility's resource needs. In addition, the Commission established a new requirement, Rule R8-60.1, for these same utilities to file SGTPs every two years with updates in the intervening years. This is the first proceeding before the Commission to consider the utilities' SGTPs.

Rule R8-60.1(a) states that the SGTPs are intended to be informational. Rule R8-60.1(c) states, "For purposes of this Rule, smart grid technologies are as set forth in Rule R8-60 ...." Rule R8-60(i)(10) states that

> the term "smart" in smart grid shall be understood to mean, but is not limited to, a system having the ability to receive, process, and send information

> and/or data – essentially establishing a two-way communication protocol. ... [s]mart grid technologies that are implemented in a smart grid deployment plan may include those that: (1) utilize digital information and controls technology to improve the reliability, security and efficiency of an electric utility's distribution or transmission system; (2) optimize grid operations dynamically; (3) improve the operational integration of distributed and/or intermittent generation sources, energy storage, demand response, demand-side resources and energy efficiency; (4) provide utility operators with data concerning the operations and status of the distribution and/or transmission system, as well as automating some operations; and/or (5) provide customers with usage information.

Rule R8-60.1(c) further states that smart grid technologies

> shall also include those that provide real-time, automated, interactive technologies that enable the optimization and/or operation of consumer devices and appliances, including metering of customer usage and provide customers with control options.

Rule R8-60.1(c) lists the information to be included in each utility's SGTP:

(1) A description of the technology for which installation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology.
(2) A smart grid maturity model "roadmap," if applicable, or roadmap from a comparable industry accepted resource suitable for the development of smart grid technology.
(3) Approximate timing and amount of capital expenditures.
(4) Cost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses.
(5) A description of existing equipment, if any, to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.
(6) Status of pilot projects and projects, including a description of whether and to what extent these projects are or will be funded by government grants.
(7) A description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.
(8) A description, if applicable, of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how

customers will authorize that information for release by the utility to third parties.

(9) A description of how the proposed smart grid technology plan will improve reliability and security of the grid.

Summary of SGTPs

DEC's SGTP

Distribution Automation: In its initial submittal, DEC explained that distribution automation (DA) upgrades would be a smart grid priority through 2014. DA involves installation of intelligent line sensors, supervisory control and data acquisition (SCADA) systems, automated re-closers, relay upgrades, and self-healing technologies that improve the reliability of the distribution network and allow power to be restored quickly after outages. DEC described its distribution management system (DMS) as the control system for the distribution grid and the linchpin that enables DA to function. DEC described efforts through 2014 to upgrade its DMS.

Advanced Metering Infrastructure: In its initial filing, DEC stated that in 2013 it began installing advanced metering infrastructure (AMI) that transmits data over radio-frequency waves. DEC stated that AMI would allow the Company to detect and respond to outages more quickly, connect and disconnect service remotely, and provide faster service by eliminating the need for appointments and for personnel to travel. DEC stated that AMI can minimize the need to estimate customer bills and allow customers to manage energy use by providing them with hourly consumption information. DEC stated that at the time of its initial filing there were about 325,000 advanced meters installed in North Carolina, with two-thirds of these deployed to residential customers. DEC stated that the total cost of its advanced meter project was $102 million, with about 25 percent of those costs reimbursed by a grant from the U.S. Department of Energy (DOE).

In its 2015 update, DEC stated that it had begun a limited-scope AMI project to install about 181,300 advanced meters at residences in the Charlotte area, with all but 4,500 being located in North Carolina. As of August 1, 2015, about 19,000 had been installed, with completion planned for the first quarter of 2016.

DEC further stated that it is in the planning phase to exchange about 4,700 large commercial and industrial and special meters with AMI meters. About 3,100 of these would be located in North Carolina, and completion is planned for the second quarter of 2016.

Also in its 2015 update, DEC stated that it is planning AMI deployment for about 20,000 North Carolina meters that were by-passed in the initial phases of its AMI project due to being located in rural areas that were outside the initial communications mesh. A 4G cellular direct connect meter is now available for deploying AMI to these meters, most of which are located at small to mid-sized commercial and industrial customer sites. DEC expects to complete this deployment in the second quarter of 2016.

Additionally, DEC stated that it expects to incur $27.1 million in capital costs for its AMI deployment through the end of 2015 and another $4.8 million in 2016. DEC's 2015 update included confidential cost-benefit information for the three AMI deployments that are underway/planned for 2015-16.

With regard to new technology installations, such as AMI, Rule R8-60.1(c)(5) requires utilities to file "[a] description of existing equipment, if any, to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment." Rather than provide this accounting-oriented information, DEC noted that some meters are being returned to inventory, some are being scrapped, some are being refurbished, and "the remaining are considered to have reached the end of useful life."

In its initial SGTP, DEC discussed the possibility and practicality of a policy that would allow customers to opt-out of having a smart meter installed, as required by the Commission's September 24, 2013 Order Granting General Rate Increase in Docket No. E-7, Sub 1026. DEC stated that it had met with the Public Staff in April of 2014 and that they had agreed that a formal AMI opt-out policy was not warranted at this time due to the limited scope of current AMI projects: "The parties agreed, however, that when larger scale AMI implementation begins, or when AMI meters become the standard metering solution, the topic should be revisited."

In its 2015 update, DEC discussed a new pilot project called Integrated Voltage/Volt-Ampere Reactive Control (IVVC) Pre-Scale Deployment. DEC stated that IVVC is one of the first advanced DMS functionalities that it is installing. IVVC would reduce system demand by optimizing voltage and reactive power across the distribution grid. DEC is demonstrating the technology at seven substations where the project team had completed most its installation work as of August 2015 and was beginning to commission IVVC in DEC's DMS.

DEP's Smart Grid Technology Plan

Distribution Automation: In its initial SGTP, DEP stated that it, too, is deploying DA on its distribution grid. New, intelligent devices like line sensors, SCADA-enabled re-closers and self-healing technology will allow automated or remote operations. When power outages occur, this field equipment will automatically isolate and reenergize sections of the grid. For DEP, the primary component of DA to date is the distribution system demand response (DSDR) project, which included the deployment of a DMS. The DMS is the control system for the distribution grid. DSDR lowers the distribution system's voltage during peak demand conditions, thus deferring the construction of two peaking combustion turbines. DEP completed DSDR in 2014.

Advanced Metering Infrastructure: In its initial SGTP DEP stated that it had replaced about 58,000 older meters in the Carolinas, primarily for commercial and industrial customers, with AMI meters in 2012-13 at a cost of about $45 million. DEP

stated that a DOE grant was expected to fully pay for these costs. DEP stated that it has not initiated any further AMI projects.

Feeder Segmentation and Self-Healing Teams: In its initial SGTP, DEP described its feeder segmentation project, an effort involving the replacement of more than 200 aging, unreliable hydraulic re-closers with new three-phase re-closers, and the installation of almost 300 new re-closers in strategic locations. DEP explained that these re-closers are line protection devices that sectionalize the feeder, isolating the section where a fault has occurred, thereby allowing rapid power restoration to customers on unaffected segments by feeding power to them from another direction. This project also involves the deployment of self-healing teams, a technology that uses distribution switches, programmable re-closers, and circuit breakers that are automated and communicate via an intelligent control system. The control system, communications system, and power line devices work as a team to automatically identify and isolate the portion of the system that is affected by a fault and to minimize the impacts of a power outage by restoring power to as many customers as possible. DEP planned to commission 20 self-healing teams by the end of 2014. Capital costs were estimated at $23.7 million, the majority of which would be reimbursed from a smart grid investment grant.

Phasor Measurement Unit Pilot: Also in its initial SGTP, DEP stated that it is participating in a pilot to evaluate the benefits of phasor measurement units (PMU). A PMU provides real-time voltage and current phase angle measurements that can be used to determine whether the transmission grid is stable.

Condition-Based Monitoring Pilot: DEP's initial SGTP described a pilot to install and evaluate sensors that allow operating transformers to be monitored remotely and continuously for signs of degradation or imminent failure. Sensors will collect and communicate data about gas and moisture in the main transformer tank, gas in the tap-changer compartment of load tap changing transformers, and the condition of bushings.

In its 2015 SGTP update, DEP described four initiatives: 1) self-healing networks, 2) an urban underground automation pilot in Raleigh, 3) an evaluation of moving to a common DMS across the Duke enterprise, and 4) a pilot deployment of "TripSavers II Re-closers."[1] DEP stated that its self-healing networks project is an expansion of the feeder segmentation and self-healing teams project that was described in its 2014 SGTP; as of August 31, 2015, 50 self-healing networks had been deployed across DEP's service territory. DEP stated that it plans to spend $3.6 million in capital through the end of 2015, $2.4 million in 2016, and $3.3 million in 2017 on self-healing networks and that these networks are integrated with DEP's DMS and SCADA systems.

[1] According to S&C Electric Company's website, TripSaver® II Cutout-Mounted Re-Closer is a self-powered, electronically controlled single-phase re-closer using vacuum fault interrupter technology, and is offered in voltage ratings of 15-kV and 25-kV. That website further stated that "this Smart Grid solution" can eliminate some permanent and momentary outages.

Also in its 2015 update, DEP described an urban underground automation pilot that is underway in Raleigh. This project will loop together equipment that is housed in nine underground vaults in a manner similar to a self-healing network. Technology will sense a loss of power and reroute supplies around the fault, returning power to most customers very quickly. The project will integrate with DEP's SCADA and DMS via a fiber optic communications system. DEP expects capital costs of $3.6 million in 2015 and $1.9 million in 2016 for this project.

In its 2015 update DEP briefly stated that it is evaluating, via a small-scale deployment, the viability of aligning the entire Duke enterprise with a single DMS vendor and platform for operational efficiency and enhanced functionality. As regards the TripSavers ll Re-Closers pilot, DEP stated that in the fall of 2015 about 125 TripSavers would be installed across Duke's jurisdictions, including 62 in North Carolina. DEP will monitor the devices through 2016, and the data will be used to assess the feasibility of a full-scale deployment.

Other Technologies Being Evaluated: In their initial filings, DEC and DEP (jointly, Duke) stated that the Company is monitoring and testing these smart grid technologies: 1) energy storage for a variety of applications; 2) the "internet of things" and connected end-use devices such as appliances; 3) charging technologies for plug-in electric vehicles; 4) micro-grids, specifically the McAlpine pilot in South Charlotte; 5) distributed intelligence, which could alleviate problems caused by the intermittency of photovoltaic solar generators; 6) low-voltage power electronics, which offers numerous improvements to distribution grid design and operations; and 7) the interoperability of grid field devices through its 'coalition of the willing' effort with device vendors.

In terms of micro-grids, Duke's 2015 updates discussed two pilots. The McAlpine micro-grid allows Charlotte fire stations to remain fully operational during prolonged grid outages. This micro-grid includes islanding switches, solar arrays, and batteries. A second micro-grid pilot at DEC's Mount Holly facility also uses solar generation and battery energy storage, but adds an "open field message bus distributed intelligence platform" with wireless communications to devices. This pilot will provide an islandable operational micro-grid to test interoperability across devices and applications.

Duke's 2015 updates described three energy storage projects that are in the planning and development stages and for which field installations are expected by the end of 2016: 1) the Rankin battery storage project pairs a 300-kW high-energy battery and a high-power capacitor with a 402-kW commercial solar installation located three miles away; 2) Duke is partnering with UNCC's EPIC Center[2] on the Marshall energy storage project. This effort involves a 1.2-MW solar facility and a 250-kW storage system. This project is testing efforts to incorporate weather, circuit and use data to optimize the solar facility's operations throughout the day and year to reduce voltage regulator operations that result from solar intermittency; and 3) testing of multiple home battery units.

[2] University of North Carolina Charlotte Energy Production and Infrastructure Center.

Duke's 2015 updates also discussed a recently concluded field testing of a low-voltage power electronic system. Duke stated that it had field tested using this system to manage power flow and peak demand, provide volt-VAR[3] optimization, enhance power quality, provide outage and fault detection and smooth solar generation's intermittency. Duke is evaluating the need for a larger pre-scaled field test prior to committing to deployment.

Dominion's SGTP

Advanced Metering Infrastructure: The Company installed more than 260,000 smart meters in Virginia starting in 2009. Dominion stated that it has not made a definitive business decision to deploy AMI across its entire service territory, but its preliminary plan is to have about 2 percent of its North Carolina meters converted to smart meters in 2019. Dominion is focusing on AMI's ability to provide remote meter reading, remote connection and disconnection of service, outage and restoration messaging, dynamic pricing, and voltage conservation.

Synchro-phasor Measurement System: Dominion stated that it is incorporating synchro-phasors into its substations and expects to spend $1 million annually across its system deploying this technology. Dominion stated that synchro-phasors provide precise, high resolution measurements of grid voltage and current, taken at locations over the entire transmission grid. Measurements are taken at very high speeds such as 30 times a second, which is 100 times faster than the conventional method of monitoring the transmission grid.

Kitty Hawk Micro-Grid Demonstration Project: Dominion is studying the interoperability of distributed generation technologies at its Kitty Hawk service center. The micro-grid demonstration includes a behind-the-meter diesel generator, a utility feed, a five-kW horizontal-axis and three vertical-axis wind turbines (3-, 4- and 5-kW), a lithium ion battery with a 75-kW storage capacity and a 25-kW discharge rate, a 6-kW solar array, protective relays, inverters, control software, metering, circuit breakers, a residential-size fuel cell, and round-the-clock monitoring.

Comments and Reply Comments

Comments of the Public Staff

The Public Staff summarized the initial SGTPs that DEC, DEP, and Dominion had submitted, stating that it had done a general review rather than focusing on strict adherence to the nine requirements of Rule R8-60.1(c), "with the intent of developing recommendations for improvements to future Smart Grid Plans." Those recommendations are as follows.

[3] VAR or "volt-ampere reactive" is a unit for measuring reactive power.

Smart grid accomplishments and expenditures incurred to date. The Public Staff stated that it would like to see more information about how the installed technologies and the information they provide will "be used in future grid operations or serve as the foundation of future grid improvements or utility services." The Public Staff noted that all three utilities listed AMI as a smart grid project and noted the possible benefits of AMI, but that "little information about how these benefits would be implemented as new customer services or improvements in service quality" was provided. The Public Staff noted that all three utilities had installed AMI meters that contained communication functionality, but that "none of the utilities is using or plans to use this functionality." The Public Staff stated that utilities should continue to seek cost-effective ways to provide customers with more detailed usage data and enhance customers' ability to use this information to manage and control their energy consumption.

Projects and expenditures expected in the next five years. The Public Staff believes future smart grid technology plans should include a more detailed roadmap

> that explains the smart grid projects and pilots underway, how those projects and pilots will inform the IOU's decision-making process regarding future investments in smart grid technologies, a projection of investments under consideration, including any financial impacts related to existing assets, and significant mileposts associated with the project and a schedule of activities.

Cost-benefit analyses. The Public Staff noted that the three utilities did not provide any cost-benefit analyses. The Public Staff stated that

> while the utilities technically complied with the requirements of R8-60.1(c)(4), which requires cost-benefit analyses for projects 'that are planned to begin within the next five years,' the Public Staff believes that future Smart Grid Plans should include a discussion of any estimated cost-benefit analyses done to justify the initial investment of funding for research and pilot projects. This would allow the Commission to review the progress of the projects and their intended benefits.

A forecast of impacts to customers, rates, and cost of utility service resulting from smart grid investments. The Public Staff stated that it would be beneficial if future plans include a forecast of how projects would impact customer services, rates, and/or the utility's cost of service. "While each IOU [investor-owned utility] provided an explanation of its smart grid investments ..., the discussion of the benefits and impacts of AMI-related projects could have been more detailed." The Public Staff noted specifically that AMI has the potential of new services in areas such as billing, usage data, energy management, and communications between the utility and customers.

Reliability and grid security. The Public Staff stated that future smart grid plans should identify specific ways the proposed technology would improve grid reliability and security.

State-specific and system-wide programs and impacts. The Public Staff stated that future SGTPs should provide information on implementation, rates, expenditures, and cost-benefit analyses on a State-specific basis.

Other issues. The Public Staff identified other issues that it believes "are a fundamental part of the debate and dialogue associated with the smart grid." In terms of AMI, the Public Staff stated that some customers are concerned about exposure to radio frequencies and privacy. As smart meters are deployed more widely, utilities will need more formal AMI meter opt-out policies that appropriately balance customer desires with AMI benefits. The Public Staff noted that the utilities have significant book value in advanced meter reading (AMR) meters that were installed in the early 2000s. Replacing these AMR meters with AMI meters should be based on robust analyses of the benefits and the rate impacts related to this potentially stranded investment. The Public Staff noted that smart grid technologies can allow customers to reduce their energy bills and that the utilities should continue to investigate cost-effective opportunities for customers to manage their consumption with time-based rates that respond to the hourly cost of energy. The Public Staff stated that smart grid technologies have the potential to "disrupt the current power generation and delivery business model," and these technologies will "likely require examination of the issues of cost-causation and cost allocation." Lastly, the Public Staff said that the Commission might want to require the utilities to

> submit a schedule for smart grid technology development and implementation, including a tentative schedule of critical decisions to be made. ... Particularly in regard to the AMI-related projects, the Smart Grid Plans did not indicate by what date the IOU would finalize any decision to adopt or reject implementation .... While the initial Smart Grid Plans filed by DEC, DEP and DNCP [Dominion] comply with Rule R8-60.1, inclusion in future Smart Grid Plans of the additional information and discussion described in these comments would be beneficial to the Commission and parties.

Comments of NCSEA/EDF

In both their initial and their reply comments, NCSEA/EDF asserted that the SGTPs filed by DEP, DEC, and Dominion are deficient because they failed to provide adequate information on customer and third-party access to energy consumption data, because they failed to provide cost-benefit analyses, and because they failed to provide adequate technology descriptions. NCSEA/EDF stated that the utilities did not comply with the following provisions in Rule R8-60.1:

> (c) ... The plan shall include:
>
> (1) A description of the technology for which installation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology.
> ...

> (4) Cost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses. ...
>
> (7) A description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.
>
> (8) A description, if applicable of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties. ...

NCSEA/EDF stated that

> [T]he utilities provided no cost-benefit analyses whatsoever .... Costs were discussed at various points and benefits were discussed at differing points, but nowhere do the filed SGT plans contain cost-benefit analyses. Accordingly, the SGT plans filed by the utilities are necessarily deficient in this regard.

NCSEA/EDF cited an Indiana case in which Duke Energy Indiana had filed much greater detail about its plans to deploy smart grid technologies than DEC and DEP had provided in this proceeding.

NCSEA/EDF requested that the Commission require the utilities to file supplemental information to fully comply with Rule R8-60.1 or hold a hearing on the adequacy of the plans. According to NCSEA/EDF, the Commission should decline to issue an order accepting the plans until the utilities have addressed their deficiencies. NCSEA/EDF said the Commission should require each utility to provide a cost-benefit analysis for full smart grid deployment throughout its territory. NCSEA/EDF also requested that the Commission initiate a rulemaking to adopt clear data access policies for customers. NCSEA/EDF stated that they

> recognize that the Commission will have to confront and resolve the need to facilitate access to energy usage data while safeguarding customer privacy. ... [The Commission should] address whether it is appropriate for the utilities to charge a fee for access to information that belongs to a customer.

NCSEA/EDF noted that in its August 23, 2013 Order Requesting Additional Information and Declining to Initiate Rulemaking,[4] "the Commission indicated that it expects the utilities to include information [in their 2014 SGTPs] about what customer usage data is being collected and how it will be accessed by customers and third parties

[4] Docket No. E-100, Sub 137.

.... NCSEA and EDF urge the Commission to view this as an appropriate time to open a rulemaking docket to adopt clear data access policies for the State."

Reply Comments of Duke

In its reply comments, Duke addressed NCSEA/EDF's concerns. Duke stated that most of the projects described in the initial plans were initiated prior to the Rule's adoption and that the deployments described in the plans were implemented with "significant U.S. Department of Energy grant funding, and therefore did not undergo a 'cost-benefit analysis'...." Similarly, Duke stated

> As of the time of the filing of the 2014 SGTPs, the Companies did not have any technologies which were scheduled for implementation in the next five years, thereby rendering many of the requirements of Rule R8-60.1 inapplicable .... The Companies respectfully submit that their 2014 SGTPs meet all applicable statutory and Commission requirements and should be approved.

As to NCSEA/EDF's proposal that the utilities be required to analyze a full smart grid deployment, Duke stated that it is not aware of any standard set of equipment or technologies that define a "smart grid," but understands that technologies are ever evolving.

In response to NCSEA/EDF's assertions that the Commission's Order in E-100, Sub 137 required the utilities to file additional information about customer access to usage data in the 2014 SGTPs, Duke said

> the Companies note that existing processes and mechanisms to provide customers' usage data have not changed based on any smart grid technology deployment at this time; therefore, [they] did not believe it was necessary to recount in the 2014 SGTPs the Companies' existing processes as described in their filings in Docket No. E-100, Sub 137, as NCSEA and EDF apparently believe the Companies should have.

Duke's reply comments also addressed the Public Staff's concerns. The Companies agreed to provide information in future plans on new customer services they intend to implement using smart grid technologies once those services are planned and scheduled. While the Public Staff requested a more detailed smart grid roadmap with a schedule of planned deployments, Duke stated that a more detailed roadmap with vague assumptions and timelines that would undoubtedly change would "cause confusion for stakeholders:"

> The Companies question the purpose and effectiveness of providing arbitrary dates for decisions to be made, or technologies to be implemented in future SGTPs. The Companies attempted to provide a high level of transparency into the 'Technology Exploration' or research and development area .... Any attempt by the Companies to try and provide a

> timeline of when those technologies would be feasible for mass deployment would be a guess at best ....

Duke provided a summary of its smart grid investments to date. It stated that DEP invested about $294 million in capital on digital grid technologies since 2007 and received about $68 million in DOE grant funding in partial reimbursement. DEP received another $27 million in DOE grant funding toward operating and maintenance (O&M) costs. Duke stated that DEC invested about $204 million in capital on digital grid technologies since 2007 and received about $51 million in DOE grant funding as partial reimbursement. DEC received another $1-million DOE grant for O&M costs.

Duke said it would be burdensome to provide detailed reporting on smart grid ideas that are determined not to be viable. Duke did agree to include in future plans the cost-benefit analyses for projects that are approved and scheduled for installation:

> However, the Companies believe that research and pilot projects are undertaken for the primary purpose of determining and validating the costs and benefits of a technology to more accurately perform a cost-benefit analysis of a full or larger scale deployment. Therefore, the Companies do not believe it is appropriate to include cost-benefit analyses for research and pilot projects.
>
> ...
>
> The Companies assert that the SGTP, like the IRP, is not designed to be an application for approval of a specific project, nor is it filed as part of a cost recovery proceeding, and therefore would oppose inclusion of rates impact and cost of utility service from smart grid investments in future SGTPs.

While the Public Staff stated that the plans should have included more information about how grid investments would improve reliability and security, Duke stated that they believed they had provided this information in their 2014 SGTPs, but agreed to try to provide more such explanations in future plans. In response to the Public Staff's recommendation that future SGTPs include deployment details on a State-specific (rather than system-wide) basis, Duke stated that this would be burdensome to provide:

> The Companies did, and propose to continue to, provide project expenditure information on an Operating Company basis within their SGTPs, which in some cases also fully captures the scope of the project.

Duke agreed with the Public Staff that additional discussion of AMI meter opt-out policies should be addressed when AMI meters are more widely deployed. They stated that any customer opting-out of an AMI meter installation should be responsible for the reasonable incremental costs incurred by the utility as a result. Duke agreed with the Public Staff that future AMI deployments should consider both the benefits of conversion to AMI technology and the costs, including stranded investments.

Duke stated that both its AMR and AMI meters have two-way communications. Both kinds of meters communicate by sending usage data and other information to the utility, and the utility communicates by sending control signals back to the meter. Duke clarified by stating that

> the advanced meters installed by the Companies also contain an internal radio, which can enable communication between the meter and consumer devices. This is the portion of the [AMI] technology functionality for which the Companies currently have no plans to enable.
>
> The Companies agree that the expansion of AMI meter deployments could enable more products and services to allow customers to manage their energy usage. At such time when those types of investments are planned and scheduled by the Company, and provided to the majority of customers, that information will be appropriately included within the SGTPs.

Duke disagreed with NCSEA/EDF's assertions that the DEC and DEP plans were deficient, stating that NCSEA/EDF's requests for supplemental filings and an evidentiary hearing to provide more information should be denied. As to the provision of customer usage information, Duke stated that on September 23, 2013, DEC and DEP filed a joint verified response to the Commission's August 23, 2013 Order Requesting Additional Information and Declining to Initiate Rulemaking in Docket No. E-100, Sub 137. The response set forth the customer usage information that is available to DEC and DEP's customers as well as the process by which customers can authorize release of that information to third parties. As to the smart grid filings that Duke has made in Indiana and Ohio, they

> were made to the appropriate state commission in cost recovery proceedings, initiated by legislation, for the purpose of obtaining those commissions' approval of cost recovery to implement large smart grid programs. ... The North Carolina 2014 SGTPs filed by DEC and DEP reflect the most complete and accurate information currently available and as required by this Commission's rules, not what is required by the Ohio or Indiana commissions.

As to NCSEA/EDF's request that the Commission initiate a rulemaking to adopt data access policies, Duke explained that this might be premature and that the Commission may instead "want to wait until such time as the Companies have additional details to provide on new types of data collected or used by smart grid technologies in the future."

Reply Comments of Dominion

Dominion also opposed NCSEA/EDF's request for an evidentiary hearing and their proposal that the utilities be required to supplement their filings:

> ...[T]he Company purposefully and methodically addressed each Rule R8-60.1(c) reporting guideline .... As all SGT reporting guidelines were adhered to ..., the Company strongly disagrees with NCSEA/EDF's unsubstantiated request for an evidentiary hearing or additional proceedings ....

Regarding NCSEA/EDF's desire to have more information about customer access to usage data filed with the SGTPs, Dominion referenced Docket No. E-100, Sub 137, as Duke had. As for cost-benefit analyses for smart grid deployment, Dominion stated that it had provided such information "where it currently exists" and also explained that "the Company is still internally evaluating its options regarding timing for deploying certain smart grid projects, such as AMI."

Dominion noted that this is the Commission's first smart grid plan proceeding and stated that as "it is likely that NCSEA/EDF will request evidentiary hearings or supplemental re-writes" of the utilities' plans in the future, "some general guidance in this area may prove valuable to all parties." Dominion went on to state:

> The Company did not interpret the Commission's intent in approving Rule R8-60.1 to create a separate and distinct smart grid resource planning process that places procedural and substantive requirements on the utilities equal to or greater than the full IRP process. DNCP submits that the purpose of the rule is limited to providing more focused "reporting" on the utility's current smart grid plans to support the full Integrated Resource Plan and not to regulate the utilities' smart grid deployment similar to a full IRP process. ... The Commission should make clear that this smart grid resource planning process is not intended to usurp utility management's role in making prudent, least cost business decisions regarding when and how to proceed with smart grid deployment for the benefit of the Company's customers and is not a substitute for rate recovery and/or regulatory approval proceedings.

Dominion also responded to the Public Staff's comments, stating that it agrees

> with the Public Staff that it is reasonable to more broadly track and include sub-projects within future SGT Plans and to report on whether such sub-projects are fully deployed or the Company has pivoted in another direction away from an ongoing smart grid strategy.

In terms of the Public Staff's request that utilities provide a "roadmap" that addresses smart grid projects and pilots and how they will inform future investment decisions, Dominion stated that it can develop a more "high level summary in support of its next SGT Plan and address the more detailed recommendations within the broader SGT Plan itself." As to the Public Staff's desire for more information about smart grid impacts on grid reliability and security, Dominion stated that it will continue to clearly identify ways smart grid technology can improve both in future plans.

Dominion stated that it has concerns with the granularity of the Public Staff's request for the "rates, expenditures, and cost-benefit analyses" of all smart grid efforts to be analyzed on a State-jurisdictional basis, and it requested that the Commission not impose any express requirements in this regard. Especially in the area of AMI, Dominion "requests that the Commission not impose detailed rate impact reporting requirements" in future smart grid plans, "as the Company continues to study the potential for full AMI deployment for our customers."

Dominion stated that its current smart meter policy provides a clear process for customers to opt-out of an AMI meter. "As AMI is more widely deployed, the Company will continue to evaluate its opt-out policy to ensure it continues to fairly and appropriately serve customer's [sic] interests."

Like Duke, Dominion expressed reservations about the Public Staff's proposal for utilities to file cost-benefit information for pilot projects as such requirements could affect the Company's efforts to innovate on a small scale with new smart grid technologies before moving toward full deployment:

> [R]eporting on the costs and benefits of future pilots should be more qualitative in nature, showing the potential reliability, operational, and/or customer benefits the pilot is designed to achieve. More refined analyses of costs and benefits would then be justified upon full scale deployment of a given smart grid initiative.

Dominion also stated that it "supports certain of the refinements recommended by the Public Staff and will endeavor to incorporate them" in future SGTPs.

Discussion, Findings and Conclusions

NCSEA/EDF were critical of the utilities' smart grid plans, asserting that they did not comply with the Commission's Rules. The Public Staff found that the SGTPs "generally" complied. The utilities argued strongly that they fully complied. Upon review of the plans, as well as the DEC and DEP 2015 updates, the Commission finds that the DEC and DEP plans did not always follow the ordering in the Rule, which made compliance a little difficult to audit. However, the utilities are correct in that some Rule provisions are irrelevant unless the utility has made the decision to deploy a specific smart grid technology in the next five years. Thus, despite NCSEA/EDF's criticisms, the Commission finds that the plans comply with the Rule, and the Commission will approve them, noting the utilities' willingness to provide additional information in future plans.

Notwithstanding the requests for more information, the Commission finds that the SGTPs on the whole were instructive and helpful. It appears that both Duke and Dominion are playing leadership roles in the smart grid arena, gaining expertise and encouraging vendors to develop applications that could someday be cost-effective and beneficial for customers. As discussed later in this Order, the Commission will seek comments on whether and how to amend its smart grid rules to better leverage the information in the

SGTPs to the benefit of the Commission and parties. First, however, the Commission will address several specific concerns raised by the SGTPs.

Metering

While the utilities all discussed their AMI deployments and pilots, the Commission finds that it would be helpful to have a "big picture" summary of the status of metering technologies in the State. Therefore, the Commission will require the utilities in their 2016 SGTPs to submit a clear accounting of the extent to which AMI meters have been installed in North Carolina and the classes and/or tariffs of customers that now have AMI. In addition, the Commission will require the utilities to provide in their 2016 SGTPs a recap of how many meters in North Carolina use traditional metering technology and/or AMR technology. As appropriate, all three utilities should provide information on any adjustments they have made to their capital accounting due to AMI, including the dollar amount of write-downs of their meter inventories. They should also provide a discussion of what services or functions the AMI meters facilitate, which of these services or functions have been activated, and whether there are any plans for pursuing others. Finally, the utilities should provide the predicted life-spans of the AMI installations that have been made.

Customer Opt-Out of AMI

In its 2014 SGTP, DEC stated that it began deploying advanced meters in 2013 and that at the time of that filing the Company planned to install about 382,000 advanced meters in its North and South Carolina territories. In its 2015 update, DEC stated that it plans to install almost 200,000 AMI meters in North Carolina via a deployment that is underway now and that is slated to be complete by the middle of 2016. While Duke and the Public Staff have in the past agreed that there was no need to address smart meter opt-outs until there is a large deployment in the State, the Commission finds that DEC's AMI installations are significant enough to warrant further discussion of this issue now. Therefore, the Commission will require DEC to submit information explaining how it is handling or proposes to handle AMI opt-out requests during the deployments described in its 2015 SGTP update. The Commission is especially interested to know whether the Company is allowing or proposes to allow opt-outs, its rationale for the approach chosen, and whether it would commit to honor those opt-outs indefinitely.

Distribution Voltage Control

DEC and DEP are considering at least two approaches to managing voltage on the distribution grid: low-voltage power electronics and IVVC. In addition, DEP has already installed DSDR, and Dominion is evaluating smart meters as a means of controlling distribution system voltage. In their 2016 smart grid plans, DEC, DEP, and Dominion should compare these approaches (and others as appropriate) in terms of costs and benefits, both of which may be expressed, if necessary, in very broad and qualitative terms.

Common DMS

In its 2015 update, DEP stated that it is evaluating the viability of aligning the entire Duke enterprise with a single DMS vendor and platform. In their 2016 SGTPs, DEC and DEP should discuss whether the Companies intend to pursue moving the DEC and DEP distribution grids toward a common operating platform and, if so, over what time horizon. To the extent that no decision has been made on this question when the SGTPs are filed, they should nonetheless provide the Commission with a discussion of the issues involved, including a high-level, indicative range of the possible costs, the benefits and possible disadvantages of a common platform, and approximately how long it would take to accomplish if the utilities were to pursue it.

DEC's Residential Energy Research Pilot Project

On October 22, 2013, DEC notified the Commission of its intent to begin a pilot involving up to 60 residential customers served by the McAlpine substation in Charlotte to research new grid optimization tools that could lead to lower costs and higher reliability. DEC stated that it would use "data loggers" to understand which appliances drive energy use and demand and to document how weather or grid conditions impact customer usage. DEC's notification stated that the Company would collect data for two years, ending in December of 2015. DEC should provide summary results of this pilot in its 2016 SGTP if it has not otherwise provided them to the Commission by that time.

NCSEA/EDF's Concerns

NCSEA/EDF asserted that the utilities' SGTPs should have included more information about plans for providing customers with additional information about their electricity use. NCSEA/EDF stated that the plans should have included more information about how usage information can be transferred to third parties. In addition, NCSEA/EDF complained that the utilities neglected to file cost/benefit analyses for smart grid technologies. NCSEA/EDF requested that the Commission require the utilities to file supplemental information or hold an evidentiary hearing. They also requested that the Commission initiate a rulemaking to establish clear data access policies. The utilities argued that they had filed all of the required information and, to the extent that they did not, it was because they did not have smart grid installations scheduled to begin "in the next five years" at the time they filed their first smart grid plans in 2014.

Rule R8-60.1(c) lists the information to be included in each utility's SGTP:

(1) A description of the technology for which installation is scheduled to begin in the next five years, including the goal and objective of that technology, options for ensuring interoperability of the technology with different technologies and the legacy system, and the life of the technology.
(2) A smart grid maturity model "roadmap," if applicable, or roadmap from a comparable industry accepted resource suitable for the development of smart grid technology.

(3) Approximate timing and amount of capital expenditures.
(4) Cost-benefit analyses for installations that are planned to begin within the next five years, including an explanation of the methodology and inputs used to perform the cost-benefit analyses.
(5) A description of existing equipment, if any, to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.
(6) Status of pilot projects and projects, including a description of whether and to what extent these projects are or will be funded by government grants.
(7) A description, if applicable, of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.
(8) A description, if applicable, of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.
[Emphasis added.]

The Commission agrees with the utilities; a strict reading of the Rule indicates that the additional information that NCSEA/EDF wanted pursuant to the Rule is not required. However, NCSEA/EDF correctly pointed out that the utilities failed to file the information required by the Commission's August 23, 2013 Order in Docket No. E-100, Sub 137. In that proceeding, NCSEA requested that the Commission initiate a rulemaking to address the accessibility of customer data. The August 23, 2013 Order states

> The Commission is persuaded that there may be a need for clarification of the manner in which Rule R8-51 and the IOUs' codes of conduct are applied in granting access to customer information. Therefore, the Commission requests that the IOUs provide detailed verified responses to the questions included in Appendix A attached to this Order. However, the Commission is not persuaded that it is appropriate at this time to initiate a rulemaking to address the accessibility of customer usage data .... Instead, it will be a more efficient use of time and resources to utilize the information provided in the IOUs' SGT plans to assist in determining whether a rulemaking is needed and, if so, the parameters of any proposed new rules. Thus, the Commission is inclined to allow the IOUs to address these issues in their SGT reports to be filed on October 1, 2014. Those reports should provide information about the customer usage data currently being collected and contemplated to be collected. Given that information, the Commission and parties will be better equipped to address the need for new guidelines for access by customers and third parties to this information.

Subsequently, DEC, DEP and Dominion filed the answers to the questions as required by the Order. However, DEC and DEP did not specifically "address these issues in the SGT reports," because their "processes and mechanisms to provide customers' usage data have not changed." Duke stated in its reply comments that the Commission might want to delay such a rule proceeding until the Companies can provide more information on the kinds of data collected or used by smart grid technologies. Similarly, Dominion did not address the need for rulemaking, and instead asserted that its "SGT Plan generally addresses how both customers and third parties may access customer data."

Therefore, while the Commission will not require the utilities to supplement their 2014 filings as NCSEA/EDF proposed, the Commission will nonetheless require them to update their responses to the questions posed in the Commission's August 23, 2013 Order and include those responses in their 2016 SGTPs. In addition, they are to address in their 2016 SGTPs whether the Commission's rules should be updated at that time in order to address customer and third party access to usage data. Finally, if any party believes that rule changes are needed, they should file their proposed rule changes in the 2016 SGTP docket.

NCSEA/EDF also requested that a hearing be scheduled to address the adequacy of the 2014 SGTPs. Rule R8-60.1(d) states that a hearing "may be scheduled at the discretion of the Commission." Since the Commission has concluded that the smart grid plans filed by the utilities comply with the Rules and that the issue of amending the Commission's Rules relative to customer and third party access to usage data will be addressed in the 2016 SGTPs, there is no need for a hearing at this time.

The Public Staff and NCSEA/EDF had several requests for additional information to be filed in the SGTPs. The utilities shall address these requests for additional information in future plans if they are able to do so.

Future Smart Grid Proceedings

Several parties noted that this is the first round of SGTPs, and all anticipated that future plans would be refined to better address the Rule's requirements and the interests of the parties and the Commission. As noted earlier, Dominion requested guidance as to the scope and intent of future smart grid proceedings. Dominion stated that the purpose of the smart grid rules "is limited to providing more focused 'reporting' on the utility's current smart grid plans ... not to regulate the utilities' smart grid deployment similar to a full IRP process." Duke asserted that "the SGTP, like the IRP, is not designed to be an application for approval of a specific project, nor is it filed as part of a cost recovery proceeding ...." The Commission agrees that these proceedings are intended to be informative, and the Commission does not anticipate using them to order utilities to make

specific smart grid investments[5] nor are they a means by which utilities should seek to secure advance prudency reviews of smart grid investments.

The Commission has found the SGTPs filed by DEC, DEP, and Dominion to be informative. The utilities are expending considerable resources to understand, demonstrate, and deploy new technology to better serve their customers, to more effectively manage the grid, and to better manage intermittent generation. The Commission has a need to understand new technology and its economic and policy implications. As a means of expanding the Commission's understanding of new grid technologies, this first smart grid proceeding has had some limitations. Short of presiding over an evidentiary hearing, there is no mechanism in the current rules for the Commission to pose questions or dialogue with the utilities and parties about the issues posed by technology choices. The Public Staff's numerous recommendations that future SGTPs contain additional information inform the Commission's finding that the current rules are deficient. While the Commission could increase the SGTP filing requirements, this approach could become burdensome for the utilities because of the wide range of questions that the Commission and parties might want addressed. In addition, while evidentiary hearings can be valuable, that aspect of the current rule appears to invite litigation, which in this sphere the Commission believes is unproductive. Therefore, the Commission requests that parties file comments suggesting ways the smart grid rules could be amended to enhance the informative aspects of future smart grid proceedings while reducing the litigious aspects of the current rules.

IT IS, THEREFORE, ORDERED as follows:

1. That NCSEA/EDF's requests that DEC, DEP, and Dominion be required to supplement their 2014 SGTPs and that an evidentiary hearing be scheduled regarding the adequacy of those plans are hereby denied;

2. That DEC, and DEP and Dominion as appropriate due to their limited AMI deployments in North Carolina, shall include in their 2016 SGTPs summaries of their metering technologies and plans, including the accounting implications of any stranded costs, as discussed in this Order;

3. That DEC shall address the issue of AMI opt-outs relative to its current and planned AMI deployments by December 1, 2015, and parties may file reply comments by January 22, 2016;

4. That DEC, DEP, and Dominion shall include in their 2016 SGTPs a discussion of the variety of technologies for controlling voltage on the distribution grid as discussed in this Order;

[5] It should be noted however that General Statute 62-42 grants the Commission authority to order an investor-owned utility to make equipment improvements if necessary to assure that customers receive adequate and sufficient electric service.

5. That DEC and DEP shall include in their 2016 SGTPs a discussion of moving to a common distribution grid operating platform, as discussed in this Order;

6. That DEC, DEP, and Dominion shall update their responses to the questions posed in the Commission's August 23, 2013 Order and include those responses in their 2016 SGTPs;

7. That DEC, DEP, and Dominion shall address in their 2016 SGTPs whether the Commission's Rules require updating in order to address customer and third party access to usage data; and

8. That parties are requested to file comments proposing amendments to Commission Rule R8-60.1 so that future smart grid proceedings are more informative, as discussed in this Order. Comments shall be filed by December 1, 2015, and reply comments shall be filed by January 8, 2016. Comments should be filed in Docket No. E-100, Sub 126.

ISSUED BY ORDER OF THE COMMISSION.

This the 5th day of November, 2015.

NORTH CAROLINA UTILITIES COMMISSION

Jackie Cox, Deputy Clerk

Commissioner Susan Warren Rabon did not participate in this decision.