BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service	Case 17-E-____

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service	Case 17-G-____

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DIRECT TESTIMONY OF THE DISTRIBUTED SYSTEM PLATFORM PANEL

July 28, 2017

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I. INTRODUCTION

Q. Please state the names of the members of the Distribution System Platform Panel ("Panel").

A. Our names are Paul Haering, Hal Turner, David Dittmann, Heather Adams, John Borchert and Tim Hayes.

Q. Mr. Haering, please state your current employer and business address.

A. I am employed by Central Hudson Gas & Electric Corporation ("Central Hudson" or the "Company") and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Mr. Haering, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am Senior Vice President of Engineering and System Operations. In that capacity, I am responsible for the engineering planning and designs for Central Hudson's gas and electric transmission and distribution systems. I am also responsible for the construction, operation, and maintenance of our electrical substations. In addition, I have responsibility for the Company's System Operations, Energy Management System, and North American Electric Reliability Corporation ("NERC") Reliability Compliance organizations.

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Q. Mr. Haering, what is your educational background and professional experience?

A. I graduated from Manhattan College in 1986 with a Bachelor of Engineering in Electrical Engineering. In 1992, I received a Masters of Electrical Engineering from Polytechnic University. In 2007, I received a Master of Business Administration from Rensselaer Polytechnic Institute. I joined Central Hudson in 1986 as a Junior Engineer in the Substation Design Section. In 1989, I was transferred to work as a Staff Engineer in the Operations Services Division, which is responsible for the operation, maintenance, and construction of the Company's substation facilities. In 1994, I was promoted to the position of Operations Supervisor in the Operations Services Division. In 2000, I was transferred to the position of Engineer in the Electric System Protection Section. In 2001, I became Section Engineer for the Distribution Engineering Section. In 2003, I was promoted to the position of Manager of Electric Transmission and Distribution. In 2004, I was promoted to the position of Manager of Electric Engineering Services. In May 2007, I was named the Assistant Vice President of Engineering and Environmental Services and, in December 2007, I was named Vice President of Engineering and Environmental Services. In August 2011, I was named Vice President of Engineering and System Operations and, in February 2017, I was named to my current position.

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Q. Mr. Haering, have you previously testified before the New York State Public Service Commission ("PSC" or "Commission")?

A. Yes. I testified in Cases 05-E-0934, 05-G-0935, 08-E-0887, 08-G-0888, 09-E-0588, 09-G-0599, 14-E-0318, and 14-E-0319.

Q. Mr. Turner, please state your current employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Mr. Turner, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am the Manager of Electric Engineering Services. In that capacity, I am responsible for the engineering planning and designs for Central Hudson's electric transmission systems and for the planning and engineering operations of Central Hudson's electric distribution systems.

Q. Mr. Turner, what is your educational background and professional experience?

A. I graduated from Rensselaer Polytechnic Institute in 1988 with a Bachelor of Science in Electrical Engineering. In 1992, I received a Master of Engineering in Electrical Power Engineering from Rensselaer Polytechnic Institute. I am currently a registered Professional Engineer in New York State. I joined Central Hudson in 1988 as a Junior Engineer in the Electric System Protection Section within our Electric Engineering Services Group. Since that time, I have held various technical and supervisory positions within both our Electric Engineering Services and Operations Services Groups. In the Electric Engineering Services Group, I had responsibility for the engineering, planning and designs for Central Hudson's electric transmission systems and for the planning and engineering operations of Central Hudson's distribution systems. In the Operations Services Group, I had responsibility for the operation, maintenance, and construction of the Company's substation facilities. In 2013, I was transferred to my current position of Manager – Electric Engineering Services.

Q. Mr. Turner, have you previously testified before the Commission?

A. Yes, I testified before the Commission in Cases 14-E-0318 and 14-G-0319.

Q. Mr. Dittmann, please state your current employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Mr. Dittmann, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am the Manager of Transmission Operations and Reliability Compliance with Central Hudson. In that capacity, I am responsible for Gas and Electric Transmission Operations, NERC Reliability Standards Compliance, including acting as the Critical Infrastructure Protection ("CIP") Senior Manager, and Operational Technology systems, including the Energy Management System, Distribution Management System and the Company's internal communication network.

Q. Mr. Dittmann, what is your educational background and professional experience?

A. I received a Bachelor of Science in Electrical Engineering from Clarkson University in 1990, a Master of Engineering in Electric Power Engineering from Rensselaer Polytechnic Institute in 1994 and a Master of Business Administration from Rensselaer Polytechnic Institute in 2007. I have a prior registration as a Professional Engineer in New York State (currently inactive). Over the last 27 years, I have been an engineering and management employee of Central Hudson. Prior to my current position, I was Manager of Electric Engineering at Central Hudson. I joined Central Hudson in 1990 as a Junior Engineer and had been promoted to several positions within the utility, including Section Engineer – Electric System Design and Manager of Customer Services.

Q. Mr. Dittmann, have you previously testified before the Commission?

A. No, I have not.

Q. Ms. Adams, please state your current employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

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Q. Ms. Adams, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am the Director of Electric Distribution and Standards. I have served in this capacity since March 2015. In addition to general supervision of Electric Distribution Planning, Operations, and Construction Standards Engineering, I oversee the development and engineering implementation of distribution capital projects. In this role, I am also responsible for the interconnection of distributed generation ("DG").

Q. Ms. Adams, what is your educational background and professional experience?

A. I graduated with a Bachelor of Science in Electrical Engineering from Lehigh University and a Master of Business Administration from New York University's Stern School of Business. I am a registered Professional Engineer in New York State. Following a summer internship, I joined Central Hudson in 2003 as a Junior Engineer in the Electric System Protection Section. In 2004, I was promoted to Assistant Engineer. In 2006, I was transferred to the Electric Distribution Planning Section, where I held positions of increasing responsibility. Most recently, these included Engineer – Section Leader, Electric Distribution Planning in 2010, Associate Director, Electric Distribution and Standards in 2013, and Director, Electric Distribution and Standards in 2015.

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Q. Ms. Adams, have you previously testified before the Commission?

A. No, I have not.

Q. Mr. Borchert, please state your current employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Mr. Borchert, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am Senior Director of Energy Policy and Transmission Development with Central Hudson. In my current position, I monitor and provide strategic input in the technical aspects of state and federal regulatory energy policy. I serve as Central Hudson's representative on various New York Independent System Operator ("NYISO") Committees, as well as the New York State Transmission Owners Technical Committee. I represent Central Hudson in the development and formation of the NY Transco, a public-private partnership of the NY Transmission Owners to jointly develop and own transmission facilities in New York.

Q. Mr. Borchert, what is your educational background and professional experience?

A. I received a Bachelor of Engineering in Electric Engineering from SUNY Maritime College in 1985, and a Master of Science degree in Electric Engineering from Polytechnic University in 1992. I am a registered Professional Engineer in the State of New York. Over the last 32 years, I have been an engineering and management employee of Central Hudson. Prior to my current position, I was Manager of Electric Engineering at Central Hudson. I joined Central Hudson in 1985 as a Junior Engineer and had been promoted to several positions within the Company, including Power Quality Services Engineer, Supervisor of New Business, Manager of Customer Services, and Manager of Gas & Mechanical Engineering.

Q. Mr. Borchert, have you previously testified before the Commission?

A. Yes. I have testified most recently in Cases 05-E-0934, 05-G-0935, 08-E-0887, and 08-G-0888.

Q. Mr. Hayes, please state your current employer and business address.

A. I am employed by Central Hudson and my business address is 284 South Avenue, Poughkeepsie, New York 12601.

Q. Mr. Hayes, in what capacity are you employed by Central Hudson and what is your scope of responsibilities?

A. I am the Manager of T&D Operations Services and Emergency Response with Central Hudson. In my current position I am responsible for Gas and Electric Distribution Dispatch Operations, Emergency Management, and several of the software applications that are used in those operations, including the Outage Management System and the Mobile Workforce Management application.

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Q. Mr. Hayes, what is your educational background and professional experience?

A. I received a Bachelor of Science in Industrial Distribution from Clarkson University in 1988 and a Master of Business Administration from Union College in 1993. Over the last 29 years, I have been an engineering and management employee of Central Hudson. Prior to my current position, I was the Section Engineer in Gas Standards and Engineering at Central Hudson. I joined Central Hudson in 1988 as a Junior Engineer and had been promoted to several positions within the Company, including Operating Supervisor in four of Central Hudson's five geographic districts.

Q. Mr. Hayes, have you previously testified before the Commission?

A. No, I have not.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of this Panel's testimony in these proceedings?

A. Our testimony describes the Company's proactive efforts to address changes required to implement the Distributed System Platform ("DSP"). We will first address system planning and Distributed Energy Resources ("DER") interconnection enhancements. Next, the Panel addresses the need to establish a centralized Distribution System Operations organization. We describe ongoing collaborative efforts that the Company is participating in with the other New York State electric utilities and stakeholders in developing the future state of the DSP. We also discuss how recovery for the Company's Non-Wire Alternative projects should be handled in the future, introduce new Non-Pipes Alternative projects, provide details on the Company's proposed battery storage projects being implemented pursuant to the Commission's Order on Distributed System Implementation Plan Filings ("Updated DSIP Order") in Case 14-M-0101,[1] as well as a proposed demonstration project specifically related to Granular Real Time pricing. As we discuss each topic, we will also describe the incremental staffing needs associated with each initiative, as summarized in the exhibits of Company Witness McGinnis.

Q. Are you sponsoring any exhibits in support of your testimony?

A. No.

III. SYSTEM PLANNING / DER INTERCONNECTION ENHANCEMENTS

Q. Please provide an overview of your testimony related to System Planning/DER Interconnection Enhancements.

A. In regard to System Planning/DER Interconnection Enhancements, the purpose of our testimony is to describe the requirements necessary to further develop our planning methods and techniques to permit us to effectively plan, forecast, and integrate higher penetration of DERs into Central Hudson's system. This section is focused on five areas: 1) Probabilistic Planning; 2) DER Forecasting; 3) Hosting Capacity; 4) the

[1] Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision and Case 16-M-0411 – In the Matter of Distributed System Implementation Plans, Order on Distributed System Implementation Plan Filings (March 9, 2017)

Interconnection Online Application Portal ("IOAP"); and 5) Interconnection Process Enhancements.

Q. Has Central Hudson previously made filings with the Commission associated with these five areas?

A. Yes, the Commission issued its Order Adopting Distribution System Implementation Plan Guidance on April 20, 2016 in Case 14-M-0101. As a result, the Company filed its Initial Distributed System Implementation Plan ("Initial DSIP") on June 30, 2016. The Company's Initial DSIP filing provided our inaugural approach to developing probabilistic planning methodologies at the Transmission Area and Substation level, our initial efforts to forecast DER by DER type at a more granular (substation) level, an initial framework and supporting whitepaper defining our Hosting Capacity analysis roadmap, and the status of our IOAP and interconnection process improvements. Together with the Joint Utilities,[2] the Company filed the Supplemental Distributed System Implementation Plan ("Supplemental DSIP") on November 1, 2016 in Case 16-M-0411. This filing provided further details on the roadmaps associated with each topic.

[2] The Joint Utilities include Central Hudson, Consolidated Edison Company of New York, Inc. (Con Edison), New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc. (O&R), and Rochester Gas and Electric Corporation.

Q. Has Central Hudson sought deferral authority and cost recovery associated with any of these items to date?

A. Yes, on March 7, 2017, Central Hudson filed its Petition Seeking New York State Public Service Commission's Approval for Deferral Accounting Authority and Recovery of Incremental Costs Associated with Reforming the Energy Vision[3] ("Cost Recovery Petition"). Specific to the Panel's discussion of these initiatives, Central Hudson sought deferral authority for the costs associated with hosting capacity analysis and Phases 1 and 2 of the IOAP, as well as on-going Initial and Supplemental DSIP and Interconnection Earnings Adjustment Mechanism costs. The Commission approved the recovery of previously incurred costs and authorized the continued deferral of costs related to the hosting capacity analysis and IOAP through its July 13, 2017 Order.

Q. Are there any other costs related to the DSP for which the Company is requesting deferral authority?

A. Yes. As we will discuss throughout our testimony, there are a number of unknowns associated with the implementation of the DSP. In Section V of our testimony, we summarize the DSP implementation expenses for which we are requesting full deferral.

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[3] Case 17-E-0113 – Petition Seeking New York State Public Service Commission's Approval for Deferral Accounting Authority and Recovery of Incremental Costs Associated with Reforming the Energy Vision (Mar. 7, 2017).

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Q. Can you provide background on Central Hudson's initial approach to developing probabilistic planning methodologies at the Transmission Area and Substation level?

A. As part of its Initial DSIP filing, Central Hudson engaged with our consultant, Nexant, to develop a probabilistic load forecasting methodology for granular transmission areas and substations. A study was undertaken to develop a system-wide avoided cost value for transmission and substation reinforcements identified using the probabilistic forecast. The study focused on substation and transmission area forecasting (it does not include circuit feeders) and was designed to meet the following objectives:

- Analyze load patterns, excess capacity, load growth rates, and the magnitude of expected infrastructure investments at a local level;
- Develop location specific forecasts of growth with probabilistic bands of growth trajectories taking into account forecast uncertainty;
- Quantify the probability of any need for infrastructure upgrades at specific locations;
- Calculate local avoided T&D costs by year and location using probabilistic methods; and
- Identify beneficial locations for DERs.

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Q. Can you provide a brief description of the study methodology?

A. Forecasts inherently include uncertainty, with the degree of uncertainty increasing for forecast years further into the future. In practice, actual growth trajectories rarely are linear and growth patterns relate to each other across time and location. Probabilistic distribution forecasting requires estimating historical load growth patterns and variability and simulating load growth trajectories. The process we used produced several thousand potential trajectories for each location, each of which reflects the non-linear nature of growth and has its own path. However, some outcomes are far more likely than others. These are summarized into probabilistic bands that identify the likelihood of load growth falling within specific confidence bands.

Q. At what level of detail were the probabilistic growth projections developed?

A. Forecasts for 10 distinct transmission areas and 54 of 69 distribution load serving substations, where detailed metering data was available, were developed.

Q. Why were forecasts not completed for all distribution load serving substations?

A. Some substations either lacked data or had lower quality data and, as a result, we were unable to estimate location specific forecasts for all substations. Substations with lower quality data include those substations with older chart style metering or those with single peak readings. The substations lacking hourly data are generally smaller stations serving relatively few customers. The portion of the system where detailed hourly data was available accounted for 89.5% of Central Hudson's 2016 peak. Central Hudson continues to improve its metering capability as part of ongoing infrastructure investments and, as of the submission date of this testimony, the Company has hourly metering at an additional four substations accounting for 91.8% of the 2016 system peak. The Capital forecast supported by Company Witness Haering includes project plans to add hourly metering to additional substations over the next five years, accounting for 98.7% of the cumulative system load data by 2021. These metering upgrades will increase the accuracy of future avoided transmission and distribution cost studies.

Q. Please describe the probabilistic forecasting process.

A. The forecasting process can be described in four main steps.

1. Clean the data. Poor data quality for some substations due to load transfers, outages, data gaps, and data recording errors has historically been a barrier to utilizing substation data for load forecasting. This step required extensive use of data analytics to identify and remove these load transfers, outages, data gaps, and data recording errors. Load transfers were of particular importance since they can be confused with load decreases or growth.

2. Estimate historical load growth trends and noise. The objective of this step was to estimate historical load growth for each year from 2010–2015 in terms of percentage growth. The year-to-year growth patterns were then used to assess the growth trend and the variability of load growth patterns; the degree of growth in a given year was related to growth during the prior year—technically known as auto-correlation. The econometric models were purposefully designed to both estimate historical load growth and allow us to weather-normalize loads for 1-in-2 weather peaking conditions.
3. Weather adjust loads for 1-in-2 and 1-in-10 conditions. Based on historical patterns, the 2013 and 2010 year load data, respectively, reflect the 1-in-2 and 1-in-10 weather conditions. Econometric models were used to weather normalize the loads and remove the inherent variation of weather across years.
4. Simulate potential load growth trajectories. The load growth forecasts were developed using probabilistic methods—Monte Carlo simulations—that produced the range of possible load growth outcomes by year. This method simulates the reality that the near term forecast has less uncertainty than forecasts 10 years out. A total of 10,000 simulations were implemented for each transmission area and 2,000 simulations were

implemented for each load area and substation. Each simulation produced a distinct growth trajectory that took into account the historical trend, variability in growth patterns, and the fact that growth patterns are auto-correlated.

The result was a full picture of the possible growth outcomes by year and location.

Q. Can you provide background on the more traditional local transmission and substation planning criteria currently used?

A. The local transmission system, as well as urban substations, are generally developed with n-1 contingency planning. For local transmission networks, the load serving capabilities ("LSC") are developed by evaluating the maximum load level at which the load can be served reliably without violating thermal or voltage limits while at the same time considering contingencies.

For basic transmission loops with only two feeds and for urban substations (those containing greater than one transformer with a lowside bus tie breaker), the LSC is determined based on the long-term emergency rating with the highest rated transmission line or substation transformer removed (unless limited by another breaker, switch, fuse, cable/conductor, bus, other component, or voltage) or design rating. For rural substations (those that contain a single transformer or multiple transformers with no lowside bus tie), the summer normal rating of the transformer or other limiting element (i.e., buswork) is applied.

Q. At what level of detail are growth estimates currently developed?

A. Central Hudson produces growth estimates for each of the 10 distinct load areas and applies those growth estimates to each individual substation within the load area. The growth rates are customized to these areas, but are not unique to each individual substation. This approach was adopted due to challenges in the data quality of substation level data as previously described. Not all substations had hourly data and many of those that did included outages, data gaps, and both permanent and temporary or seasonal load transfers between substations. Unless identified and removed, load transfers can be confused with growth or decay in local peak loads. Because most load transfers occur between substations in a specific load area, load areas provided a stable unit of analysis for developing forecasts.

Q. Do forecast loads in excess of the LSC or design ratings automatically trigger an infrastructure upgrade?

A. The forecast load is allowed to exceed the LSC without triggering an infrastructure upgrade, with the understanding of the low probability of a contingency occurring during peak loading.

Central Hudson has specified explicit risk tolerances, based on the total hours that forecast load can exceed design ratings, which vary by category and are summarized in Table 1 below. More risk is tolerated for less critical components of the system.

Table 1: Risk Tolerances

Category	Risk Tolerance
Transmission Network	2% of seasonal capability period (88 hours)
Transmission Loop	6% of seasonal capability period (263 hours)
Urban Substation	6% of seasonal capability period (263 hours)
Rural Substation	8% of seasonal capability period (350 hours) or 7 MVA unreserved

Q. Do you envision modifying the risk criteria described above?

A. As penetration of DERs increases to the point of significantly changing a load curve at a substation, risk criteria may need to be reevaluated, particularly in the case of intermittent resources.

Q. Does Central Hudson plan on utilizing its traditional planning methodologies or transitioning to a more probabilistic methodology in the future?

A. Central Hudson plans on utilizing both our traditional planning methodologies and the more probabilistic approach in the future. The recent Avoided T & D Cost Study was Central Hudson’s first study based on probabilistic methodologies with the results of this study addressing a number of requirements outlined in the Order Adopting Distributed System Implementation Plan Guidance (“DSIP Guidance Order”), issued on April 20, 2016 in Case 14-M-0101. In addition, since the probabilistic approach we utilized identified a system-wide value based on probabilistic forecasts developed at a granular level, we believe it represented a superior approach to determining system wide value, although it is likely that our investment-triggering criteria utilized for the system-wide value will need to be refined over time. This study and the associated analysis can both serve the aforementioned purpose of developing forecasts at granular levels.

Q. Does Central Hudson plan on modifying its probabilistic methodologies in the future?

A. Central Hudson plans on continuing to develop and improve our use of probabilistic methodologies. In addition, the overall risk profile utilized within the system wide study was significantly more conservative than our traditional approach and will require refinement as we gain experience.

Q. Is Central Hudson planning on completing a similar study in the future?

A. Yes, Central Hudson plans on completing this type of study every two years. The timing of the study will correspond with the update of our BCA handbook and filing of future DSIPs.

Q. Are there specific resource requirements necessary to complete this study work and further develop probabilistic planning methodologies?

A. As indicated, Central Hudson engaged a consultant, Nexant, to complete this initial study. The initiative included compiling the historic load data, assisting with the data cleansing efforts and providing information for traditional reinforcement projects and associated cost estimates. Central Hudson sees significant value in refining and completing similar Avoided T & D Costs Studies on an ongoing basis and further incorporating probabilistic methodologies into our planning processes. This type of analyses will become core to our planning functions in the future. The Company feels there are significant benefits to developing the internal capabilities necessary to complete these probabilistic analyses in the future versus contracting out the work. The necessary incremental resources for this work effort were identified within our Initial DSIP. Two Junior Engineers are required to complete probabilistic planning: one in Electric Distribution Planning and another in Electric Transmission Planning. These resources, as summarized in the exhibits of Company Witness McGinnis, will also be required to complete the DER forecasting, described later in this section. As probabilistic planning becomes a core Company function and the Company develops the necessary skills and tool sets to perform probabilistic planning analyses, this type of work will be completed in-house as part of our normal planning processes.

Q. Has DER forecasting been identified within System Planning as an area requiring further development?

A. Yes.

Q. Can you provide some background on Central Hudson's current approach to DER forecasting?

A. Within its electric system peak demand forecast, Central Hudson historically has accounted for adjustments due to energy efficiency ("EE") and DERs, specifically net-metered customer-sited photovoltaic ("PV") units. Once the base projections are developed, adjustments for EE and PV are applied to yield net projections. Since the impacts of all EE and PV are embedded in the historical demand data, the demand projections must be reduced by an estimate of the incremental impacts of future EE and PV.

Q. Has Central Hudson performed any DER forecasting at a more granular level than its current approach to DER forecasting?

A. As part of our Initial DSIP filing, Central Hudson engaged with Nexant to produce DER penetration forecasts for EE end uses, PV, and electric vehicles ("EV"). Demand Response ("DR") was not forecasted, as it is fully managed by Central Hudson. Battery storage was not included due to lack of data; no public data source was available on either historical or forecast penetration of behind-the-meter batteries or customer adoption rates. Although the details of each analysis differed for each DER, the methodology was guided by common principles and was broadly similar across DERs. Where possible, existing forecasts were used to estimate future annual penetration; otherwise, historical trends were analyzed and extrapolated. If historical locational data on the distribution of a DER was available, those distributions were used for forecast years, and if no such data was available, billing data was used to distribute penetration according to the population's annual usage. Finally, where forecasts were only available in annual MWh, penetration in each hour was estimated based on end use specific load shapes, or demand, allocated to each of the 8,760 hours in a year on a percentage basis – a normalized load shape. Multiplying the load shapes on a percentage basis with annual MWh values ultimately yielded forecasts in kW on an hourly, weather adjusted basis for each forecast year.

Q. Earlier in your testimony the Panel discussed the Company's probabilistic approach to demand forecasting. Were the DER forecasting methodologies probabilistic?

A. As described above, the DER forecasts were not probabilistic. Instead, explicit goals were reflected for EE while interconnection queue activity was utilized to forecast solar PV. The EV forecast was based on existing vendor pre-order data.

Q. Are there recommended improvements to your DER forecasting methodologies going forward?

A. As indicated, Central Hudson is transitioning its Distribution System Planning process to incorporate probabilistic and more granular elements. The DER forecasts were not fully integrated into the system peak forecast. Future iterations will need to focus on coordinating the integration of DER forecasts into location specific and system peak forecasts. Additional refinements will also be needed to transition DER forecasts to a probabilistic forecast of intermittent resources. DERs have risk associated with performance (especially intermittent resources), which can be exacerbated by increasing adoption rates. In order for the DSP to be able to effectively rely on and fully leverage these resources, enhanced monitoring, control, and visibility will be critical. With the increased intermittency associated with many DERs, application of a linear forecast, along with Engineering knowledge and judgment, may be insufficient to recognize the range of potential generation and load scenarios. While in the past a net load forecast was sufficient for planning, the forecast going forward must be separated into a DER forecast and base load. DER forecasts should consider not only technical drivers of load shapes, but also current and anticipated policy decisions and interconnection queues that will impact the penetration of DERs.

Q. Are there other challenges specific to DER forecasting?

A. Yes. The incorporation of DER into location specific forecasts is a challenging issue. Ignoring DER adoption in location-specific forecasts may not reflect the reality that customers are installing solar PV, purchasing EVs, and adopting EE on their own. However, incorporating DERs that have not yet been built or installed into a forecast can dilute any locational value signals and potentially slow down DER adoption. A prerequisite for more improved forecasting approaches is accurate tracking of DERs and dispatch events so that both the gross and net (gross minus load shaping DERs) loads can be estimated. Many types of DERs—e.g., naturally occurring EE and EVs—are not administered by a utility and do not require an interconnection. Another consideration is forecast uncertainty. Forecasting DERs early in the adoption process such as battery storage and EVs is highly uncertain and, at the same time, difficult to quantify.

Q. With this in mind, do you envision specific multiple use cases for DER forecasts?

A. Yes, we envision multiple use cases for DER forecasts. One likely use case is to reflect a system peak demand forecast which accounts for adjustments due to EE and DERs; specifically, net-metered customer-sited PV to yield net projections and an associated forecast with the demand projections reduced by an estimate of the incremental impacts of future DER. In addition, we foresee more granular/location-specific use cases. These use cases potentially would be utilized in conjunction with probabilistic demand forecasting methodologies to determine system and locational values. In addition, there may be forecasts utilized to determine locational growth scenarios with embedded naturally occurring DER (i.e., customer adopted EE and EV) as input into the planning process to perform more traditional needs assessments.

Q. Are there specific forecasting, skill, and resource improvements necessary to perform DER forecasts in the future?

A. As discussed above, to better plan for and effectively value and accommodate increased levels of different types of DERs onto our system, advances in DER forecasting will be required. The development of additional skill sets and knowledge bases will be required both in the Transmission and Distribution Planning Areas to complete this work.

Q. Are there additional tasks associated with the proliferation of DERs that will require the addition of resources within the Electric Transmission and Distribution Planning Areas?

A. Yes, the Company's existing planning methodologies will need to be augmented to account for both the increased penetration of DERs and the intermittency associated with some of these technologies. The DERs interconnected on both the underlying distribution system and those interconnected directly to the transmission system will require modifications to our planning methodologies. The use of probabilistic DER planning approaches will need to be investigated. This will require the development of new skill sets and completion of tasks not currently performed. As identified within our Initial DSIP, in order to more accurately forecast and ultimately accommodate higher penetrations of DERs onto Central Hudson's system, DER forecasting requires incremental work. The two Junior Engineers identified earlier in this section to support probabilistic planning will also support DER forecasting.

Q. Will new models or software be required to complete this work?

A. Specialized forecasting programs with the ability to specifically handle differing DER technologies and to address varying DER penetration rates, intermittency and other variables may be required.

Q. Moving on to the topic of Hosting Capacity, please summarize the Company's efforts to date regarding Hosting Capacity analysis.

A. To support each utility's Initial DSIP, the Joint Utilities worked together with the Electric Power Research Institute ("EPRI") to 1) develop a whitepaper that supported the use of the EPRI Streamlined Hosting Capacity methodology; 2) identify utility data gaps; and 3) provide an implementation roadmap.[4] The Joint Utilities then completed a stakeholder engagement series consisting of six meetings to gather feedback on its proposal and provide additional details and timelines. The results of this discussion are detailed in the Supplemental DSIP. The parties to the stakeholder engagement sessions agreed that the EPRI streamlined approach for large centralized solar PV would be utilized for analysis. A four stage roadmap was also developed:

1. Stage 1 – Distribution Indicators (2016 – Early 2017): identifies where interconnection costs may be higher

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[4] Electric Power Research Institute, Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State, Report No. 3002008848 (June 2016) ("EPRI Roadmap").

2. Stage 2 – Hosting Capacity Evaluations (Late 2016 – Mid 2018): performs analysis at the feeder level for the three-phase mainline
3. Stage 3 – Advanced Hosting Capacity Evaluations (Begins late 2017): performs analysis at the nodal level; considers some aspects of substation and transmission constraints as well as system contingencies
4. Stage 4 – Fully Integrated DER Value Assessments: extends beyond hosting capacity to consider value to the distribution system.

On March 9, 2017, the Updated DSIP Order was issued requiring the completion of Stage 2 Hosting Capacity evaluations for solar PV by October 1, 2017. The Commission stated in the Updated DSIP Order that, "One of the more fundamental elements of information that has been missing to date is hosting capacity data."[5]

Q. How many feeders require hosting capacity analysis, and how often will they be updated?

A. The Updated DSIP Order requires hosting capacity analysis for all circuits "at and above 12kV."[6] Based upon that criteria, approximately 230 of Central Hudson's feeders require hosting capacity analysis. The interconnected and queued DG will be updated monthly, and the hosting

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[5] Id. at 8.

[6] Id. at 14.

capacity analysis will be updated annually for Stage 2. The timeline for initial development and refresh frequency for Stages 3 and 4 have yet to be defined, but the scoping of Stage 3 is anticipated to commence in the latter half of 2017, with significant work efforts continuing into, and increasing during, the Rate Year.

Q. What is required to run the hosting capacity analysis?

A. A wealth of information must first be accumulated from various sources and cleaned or modified to meet the needs of the hosting capacity analysis. Data from various sources are combined, analyzed, and subsequently transferred to the next step in the process.

Specifically, as a part of its Distribution Automation project, the Company has been performing a field assessment of system information, such as conductor data, phasing, and protective device information which are needed for hosting capacity analysis. Data from sources such as the Company's Geographic Information System ("GIS") and Outage Management System ("OMS") must be cleaned to achieve a level of accuracy and precision necessary for Hosting Capacity analysis. For example, adjustments are required to provide the appropriate current and voltage levels as phasing or connection points change, which is significant for a hosting capacity analysis but irrelevant to outage prediction models. Metering data stored in our mainframe database is required to be scrubbed for feeder daytime minimum and peak load scenarios, and protective device settings are required to be gathered from a separate relaying database. After running loadflow for the daytime minimum and peak load scenarios, this data is then extracted and imported into the EPRI Distribution Resource Integration and Value Estimation ("DRIVE") tool, where hosting capacity analysis is run and a minimum and maximum range is produced for a variety of attributes (e.g., thermal, voltage, protection). The results of the analysis are then added to the GIS system per a detailed technical specification, and the maps are produced. As nodal and contingency analysis is completed, additional steps will be required to manage the additional complexities associated with Stage 3 analysis.

Q. Is Central Hudson performing the hosting capacity work with internal resources?

A. Central Hudson is performing some of the model preparation and data compilation, as well as complex components of the GIS map development, with internal resources. But the initial DRIVE tool analysis to meet the October 1, 2017 deadline is being contracted to a consultant.

Q. Will Central Hudson continue to contract out this analysis to a consultant?

A. No. With the proliferation of DER as described in both this testimony and the testimony of the EAM Panel, hosting capacity analysis must become a core competency of the Electric Distribution Planning process of the future as it converges with forecasting, non-wires alternatives, and capital investment needs. While Central Hudson contracted the initial DRIVE analysis, the Company is seeking an additional Junior Engineer in the Electric Distribution Planning department to update Stage 2 analysis and complete the later stages of the analysis as identified in the exhibits of Company Witness McGinnis. Additionally, an incremental GIS Analyst (described in further detail at the end of this section) is required to support other mapping efforts and to complete the mapping associated with hosting capacity.

Q. What additional software upgrades may be required for hosting capacity analysis?

A. Central Hudson is working with Electrical Distribution Design ("EDD") to develop a tool to extract the data from EDD's Distribution Engineering Workstation ("DEW") modeling software into a format that can be imported into the EPRI DRIVE tool on a research and development basis. In addition, it is anticipated that Milsoft, another Distribution Planning load flow vendor utilized by the Company, may develop a module within its existing Windmil tool that the Company already owns. No pricing information is available for the module at this time, but once available, Central Hudson may be required to purchase the module along with any maintenance and support fees. The Company has authorization to defer any incremental software purchase, integration, and licensing costs associated with purchasing a hosting capacity analysis tool.

Q. Is there any additional work associated with hosting capacity analysis?

A. Yes, the DSIP Guidance Order also required that the utilities propose projects to increase hosting capacity. One of Central Hudson's proposed energy storage projects will increase hosting capacity and is described in Section VII of our testimony. In addition, projects associated with our routine capital plan to convert aging 4kV infrastructure to 13.2kV operation, replace small wire (#4 and #6 copper) with that of our current standards, and modernize substation control, relaying and metering, all increase hosting capacity. These types of projects are generally described in the testimony of Company Witness Haering.

Q. With regards to the IOAP, please summarize the requirements and current status of the project.

A. The Department of Public Service Staff ("Staff") hired EPRI to develop the New York Interconnection Portal Functional Requirements[7] ("IOAP Requirements"), which were made available to the Company in September 2016. The IOAP Requirements document describes three phases of the project: Phase 1 – Automate Application Management (2016-2017); Phase 2 – Automate SIR Technical Screening (end of 2017); and Phase 3 – Full Automation of all Processes (2017-2019). As a result of the timelines established in the IOAP Requirements and refined within the DSIP Guidance Order, and the material cost implications, the

7 New York State Department of Public Service, New York Interconnection Online Application Portal Functional Requirements, (Sept. 9, 2016).

Company petitioned for deferral authority for costs associated with this project. The Commission at its July 13, 2017 session authorized the Company to continue to defer the costs related to this project. The Company has been proceeding with the project, including selecting a vendor and moving forward with implementation, and anticipates being substantially complete with Phase 1 of the IOAP by October 1, 2017 as specified in the DSIP Guidance Order.

Q. What is Central Hudson doing to achieve Phase 2 of the IOAP?

A. Central Hudson is working with EDD to automate New York State Standardized Interconnection Requirements ("SIR") screening analysis per the Phase 2 specifications in the IOAP requirements within its DEW software. The front-end portal vendor will also subcontract EDD to integrate the two products to provide screening results via the portal.

Q. Will Phase 2 of the IOAP be completed prior to the July 1, 2018?

A. Work will commence on Phase 2 prior to July 1, 2018, but revisions to the SIR screens are currently being discussed within the Interconnection Technical Working Group ("ITWG"). Thus, the timing of the automation of screening criteria will be contingent upon the updates to the screens being completed within the SIR.

Q. When will Phase 3 of the IOAP be completed?

A. It is anticipated that work on Phase 3 of the IOAP will commence in 2018, but the scope has yet to be fully defined by Staff and the Joint Utilities.

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Q. What resources is the Company seeking for completion of this project?

A. In addition to cost recovery for the capital and expense components for Phase 2 and 3 of the IOAP, the Company is seeking one additional Engineering Technician for the implementation of those phases, as well as the on-going maintenance and support of the product and development of new work flows. The product is a cloud based solution that requires the Company to update and maintain the workflows and act as a first level of support for users (primarily DG developers) in addition to any one-time workflow development and integration.

Q. Other than hosting capacity and the IOAP, are additional enhancements to the interconnection process anticipated?

A. Yes. As described in the testimony of the EAM Panel, the ITWG and Interconnection Policy Working Group are actively improving the interconnection process. Each team meets six to 12 times per year, with two to three technical deliverables required between meetings for each team, along with presentation preparation.

Q. Are there any additional resource needs that the Company is seeking to address related to Interconnections?

A. The proliferation of large scale remote net metering and community DG project applications has created a requirement for an additional position in the Business Development group as identified in the exhibits of Company Witness McGinnis. As described in the testimony of the EAM Panel, applications greater than 50kW increased by 576% from 2015 to 2016, most of which are 2 MW in size. The substation and distribution system upgrades associated with these installations require coordination internally to ensure material lead times, project cost estimating, design, engineering, and construction are aligned. The newly created position will shift project management responsibility from the Electric Distribution Planning team to Business Development. The position will require technical expertise, knowledge of three phase electric service construction and metering, and project management capability. This employee will be the customer's single point of contact from the point at which a down payment for construction is received to completion of the project.

Q. Are there any additional resource requirements necessary to the support the DSP system planning and DER interconnection enhancements?

A. An additional GIS Analyst will be required to complete incremental GIS work associated with DSP enablement. As discussed in the hosting capacity and interconnection process improvement sections, accurate GIS data is foundational to the work performed in these areas. In addition, the ability to generate public-facing GIS maps displaying increasing levels of system information is becoming critical. The foundational GIS data will need to be kept current to ensure these processes and our Distribution Management System ("DMS"), which is discussed in the next section of our testimony, remain current with system conditions. In addition to supporting the GIS data efforts, the additional GIS resource will also be required to support the generation of new maps and enhancements and updates to the system data and hosting capacity maps on a going forward basis.

IV. DISTRIBUTION SYSTEM OPERATIONS

Q. How is the Company's electric distribution system operated today?

A. Central Hudson has five operating districts that operate independently. Operating Authority for the distribution system resides in each of the five Operating Districts. There is, however, limited remote control and monitoring of the distribution system. Responses to outages are managed by the centralized Distribution Dispatch Organization.

Q. Does Central Hudson need to establish a centralized Distribution System Operations organization?

A. Yes. For the past three years, Central Hudson has been working towards the implementation of a DMS. The DMS will allow remote control and monitoring of the electric distribution system. The implementation of the DMS will allow for the use of advanced applications, including Fault Location Isolation and Service Restoration ("FLISR") and Conservation Voltage Reduction ("CVR") / VoltVAR Optimization ("VVO"). The DMS is designed for use by a Centralized Distribution System Operations organization to make the most efficient use of FLISR and CVR/VVO. Also, it would not be cost effective to install a DMS in each of the

Operating Districts. Several of Central Hudson's distribution substations feed circuits that are in more than one operating district. Optimizing the bus voltage at the substation will impact all of the feeders from that substation regardless of whether the circuits are located in the same operating district. Central Hudson will be able to optimize the performance of the electric distribution system by transferring load without regard to the existing operating district borders that currently define Central Hudson's distributed operational authority. With the implementation of the new technology and the associated benefits that flow from its adoption, the organization that is responsible for controlling the system must be able to visualize the entire distribution network as a single system. Central Hudson's vision for Distribution System Operations is described in detail in the Electric Distribution System Operations Whitepaper which was included as Appendix C to the Company's Initial DSIP.

Q. What will be the role of the Distribution System Operators?

A. The Distribution System Operators will be Central Hudson employees who have the training, expertise, and authorization to operate the DMS and the Electric Distribution System. When the DMS is fully functional, the operators will manage, from a centralized location, the entire Central Hudson distribution system 24 hours per day, 365 days a year. This will include ensuring that all customers are receiving the optimum voltage using CVR/VVO and timely restoration by working closely with our existing Distribution Dispatchers and using the FLISR capabilities of the DMS.

Q. Will the Distribution System Operators have other safety-related responsibilities in addition to those just described?

A. Yes. In addition to responding to electric interruptions, as part of the routine monitoring of the distribution system, the DMS will generate alarms whenever a key index falls outside of an established range. It will be the operator’s responsibility to acknowledge each of these alarms and respond accordingly. The safety of our line crews is critically important. Therefore, we will develop procedures to disable the automation in areas where we have field crews working on the distribution system. The operators will have responsibility for performing the necessary switching to maintain the safety of our field forces during this type of work.

Q. What role will the Distribution System Operators have with regard to DERs?

A. The Distribution System Operators will be responsible for monitoring DERs on the system and potentially dispatching / controlling DERs. To the extent that a DER Management System (“DERMS”) or other DER management or market platform is implemented, the Distribution System Operators will be tasked with the responsibility for using this system.

Q. How will the technology that is used by the current Distribution Dispatchers be modified as a result of the DMS implementation?

A. Initially the DMS will be integrated with the current OMS. The two systems will draw from two separate, but connected databases. After the DMS is established, we will transition to an OMS that was purchased with our DMS product. This transition will allow us to utilize a single database, thereby eliminating the potential for a conflict between the DMS and OMS outage predictions and reducing the effort needed to maintain dual databases. The phase-in of the DMS's OMS features, however, will not begin until after the conclusion of the Rate Year.

Q. How will the existing Distribution Dispatchers interact with the Distribution System Operators?

A. Because they share responsibility for the reliability of the electric distribution system, communication between the Dispatchers and the Distribution System Operators will be critically important. They will be co-located in workstation pods. Each team will be responsible for a discrete geographic area. During electrical outages, the Distribution System Operators will be responsible for the operation of all remotely controllable devices. The Distribution Dispatchers will be responsible for assigning field personnel to perform any non-automated switching and to make repairs as necessary to restore power. The DMS will be utilized to develop all unscheduled switching.

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Q. Will the operation of the natural gas distribution system be affected by the implementation of the DMS?

A. The Distribution Dispatchers will retain the responsibility for assigning the appropriate field crews to an odor complaint, a leak, and all other gas related events. Initially, the DMS will be used to monitor gas pressure and station alarms at a limited number of gas regulator station locations. As we gain experience with the system, Central Hudson plans to use the DMS to monitor natural gas distribution system pressures and station alarms at additional locations.

Q. How will Transmission System Operations work with Distribution System Operations?

A. The DMS and the Energy Management System ("EMS") require real time input from many of the same field devices, such as distribution circuit breakers and load tap changers in the distribution substations. Therefore, the Transmission and Distribution System Operators will need joint control and monitoring of these devices. Procedures that establish the responsibilities associated with the operation of these devices will be developed as part of the transition to centralized control. When a distribution circuit breaker is remotely operated by either a Transmission or Distribution System Operator, communication between the two operators will be required. There is a benefit of having the two groups located in the same building to ensure that in-person communication is not adversely impacted. We will address the location of these System Operators later in testimony.

Q. What other steps need to be taken to transition from the current distributed control environment to a centralized control environment?

A. The relationships between the line organization and the centralized control organization have to be defined, implemented, and monitored. This will require training for both the line organization as well as the operators.

Q. What is the timing of the technology improvements that will be needed?

A. The DMS will become available for production in 2017. The underlying GIS database is currently being developed and will be rolled out over a several year period. The modeling of the distribution circuitry in the Fishkill district will be converted into the GIS database, reviewed and linked to the DMS in 2017; the other four Operating Districts will follow at a pace of approximately one district per year. The communication network and the distribution automation equipment being installed on Central Hudson's distribution system will approximately parallel the time line of the GIS database completion.

Q. What human resource modifications will be needed to implement the new technology?

A. A Distribution System Engineer, a Telecommunication System Designer, and a DMS Analyst will be added in 2017. The responsibilities of the Distribution System Engineer position include working with the Director of

Distribution System Operations to develop and implement the procedures that will be utilized by both the electric field forces and the centralized operations group to monitor and control the electric distribution system. This position will also be responsible for testing and modifying the DMS and its associated database in preparation for its full implementation. As the DMS enters into daily operation, this position will also be responsible for training on the system and, ultimately, maintenance and support of the system and its users. The engineer will also work towards fine tuning of the underlying electric model so that the DMS can eventually be operated automatically (closed loop). In this mode, the DMS would have the authority to restore customers without review or approval by an operator. The responsibilities of the Telecommunication System Designer position includes the design of the Company's communication network including overseeing the planning, design construction, and testing and performance evaluation of the network. The responsibilities of the DMS Analyst include building and providing technical support for the Distribution Management System, which is used to monitor, control, and optimize the Electric Distribution System.

Q. What Human Resource modifications will be needed to operate the Distribution Management System?

A. The system will also require employees to operate it. We will add two Distribution System Operators in 2018. They will have the responsibility to operate the DMS during business hours in a limited geographic area. As the system becomes available in more areas, the Company will gradually add more operators. We will add four more in 2019 and six more in 2020. This complement will allow us to operate the DMS 24 hours per day throughout the service territory. These 12 Distribution System Operators will ultimately rotate on a six week shift schedule similar to the shift that is currently being used by our Distribution Dispatch and Transmission System Operations organizations. Incremental costs of this additional staffing are primarily labor costs, but the complexity of the system will require the operators to receive significant training. These incremental training needs were provided to the Training and Development Panel and are included in the incremental revenue requirements.

Q. With the introduction of more complex technology and additional human resources, are the current facilities adequate?

A. No, the existing Distribution Dispatch center is too small and does not have the technology needed to support the DMS. In addition, there is a need to establish a Distribution Alternate Control Center to ensure that Central Hudson retains the ability to monitor and control the distribution system in the event that the Distribution Primary Control Center becomes unavailable. Initially, existing space in the South Road Headquarters will be outfitted with the basic furnishings necessary to operate the OMS and DMS. This space is immediately above the existing Transmission Primary

Control Center and will serve as the initial Distribution Primary Control Center. It is planned that in 2020 the DMS will be functional for nearly all of Central Hudson's distribution system. At that point, the Transmission and Distribution Primary Control Centers will be moved to a new facility that will be co-located with the new Training Center as discussed in the testimony of the Training and Development Panel. After both Primary Control Centers are relocated to the new Training Center facility, the control centers at the South Road headquarters will be re-designated as the Transmission and Distribution Alternate Control Centers. Design and permitting of the new facility will begin in July 2018 with planned ground breaking for construction in March 2019 and construction completed by December 2020 as shown in the proposed facility timeline in the Exhibit __ (TDP-4) sponsored by the Training and Development Panel. The new space will be adequate to house both the existing Transmission System Operations and Distribution Dispatch Center employees and the additional staffing that is necessary to operate the new DMS. The new facility will provide the necessary security and redundancy to meet or exceed all regulations and ensure reliable service to our customers. The facility will also contain the necessary furnishings to accommodate the demands of a 24 hour shift schedule. The sit/stand work stations will have multiple computers and monitors to facilitate views of the various computer systems that will be used by the Distribution Dispatchers and the

Transmission and Distribution System Operators. The new facility will include a data center for the EMS and DMS servers as well as office, conference, training, breakroom, restroom, and storage space for the managerial and support staff. Additional detail on the construction of the Training Center can be found in the testimony of the Training and Development Panel.

Q. Were other design configurations considered prior to deciding upon this direction?

A. Yes, there were several alternatives considered before selecting this option. In addition to total overall cost, several other factors were considered during the decision making process. Security, redundancy, system reliability, communication, and industry best practices were all balanced to select the best alternative. During the process, we consulted with multiple architectural firms and visited several recently constructed control centers. In addition to considering locating the new control centers with the new Training Center, other potential alternatives were considered including adding additional floor space in the South Road Headquarters, utilizing a new building at the South Road Headquarters, and using existing space in our Kingston facility.

Q. Are there additional operating and maintenance expenses associated with the Primary Control Center and have these costs been included in the Company’s revenue requirement?

A. While the Company does anticipate additional operating and maintenance expense related to general operating costs and security, as indicated in the testimony and exhibits of the Company's Training and Development Panel, based on the stage of the project at the time of filing, the Company requests update of these expenses at the time of Brief on Exceptions. Furthermore, the Company requests full deferral of incremental O&M expense associated with the Primary Control Center as the certainty, timing, and magnitude of these expenses are unknown and have not been reflected in the development of the revenue requirement.

V. DSP FORMATION AND POLICY

Q. Please provide an overview of the DSP formation activities undertaken by Central Hudson.

A. Central Hudson has been pursuing the activities outlined in the Initial DSIP and Supplemental DSIP filed in 2016, as modified through the Updated DSIP Order issued in 2017. These activities, coordinated through the Joint Utilities, have included nine major team activities working to advance the implementation of the DSP and in addition include other efforts such as DSP Vision efforts meant to accelerate the market development of the DSP.

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Q. What additional activities will need to be undertaken by Central Hudson as the DSP advances and what may prompt these changes?

A. In addition to the foundational investments that Central Hudson has been making related to Distribution Automation, Distribution Management System, and the communication and IT efforts under Network Strategy, there will likely need to be advances in the Company's ability to monitor and control DER that is being dispatched either through the wholesale markets or through the DSP. These advances will be prompted by the establishment of a liquid wholesale or DSP DER market, the allowance of the installation of DER beyond firm capacity, or levels of DER penetration that would result in the curtailing of DER in order to maintain a reliable distribution system.

Q. Has Central Hudson included projects or costs related to a DERMS or other DER management or market platform in this rate filing?

A. No, it is not currently envisioned that these investments will be needed within the Rate Year.

Q. How does Central Hudson propose to recover incremental costs associated with future grid modernization expenses?

A. Central Hudson proposes that the costs for these activities be deferred for future return to or collection from customers, with the costs assumed in delivery rates serving as the basis for the deferral. The over- or under-collection will be included in the Rate Adjustment Mechanism ("RAM") described further in the testimony of the Accounting and Tax Panel. Central Hudson anticipates that these grid modernization costs will include: Central Hudson's share of the consultant services to support the Joint Utility efforts; support in the preparation of an updated DSIP filing; and the revenue requirements related to the Interconnection Portal, hosting capacity analysis, energy storage projects and Non-Pipes Alternatives.

VI. NON WIRES AND NON PIPES ALTERNATIVES

Q. How will Central Hudson notify the Commission of new Non-Wires Alternatives ("NWA") or Non-Pipes Alternatives ("NPA") projects?

A. Central Hudson will submit an implementation plan for each identified NWA or NPA that includes, at a minimum, a detailed measurement and verification procedure(s), the solutions to be included, a demonstration of whether the costs of each NWA or NPA are incremental to the Company's revenue requirement or will be displacing a project subject to the Net Plant Reconciliation mechanism(s), and a customer and community outreach plan. Central Hudson will file updates to each implementation plan on an annual basis by December 1st of each year. The implementation plan will also include a Benefit Cost Analysis, for each NWA or NPA identified, performed in consultation with Staff and in accordance with Central Hudson's BCA Handbook for each NWA and NPA.

DIRECT TESTIMONY OF THE DISTRIBUTED SYSTEM PLATFORM PANEL

Q. How does Central Hudson propose to recover incremental costs associated with the development and implementation of future NWAs or NPAs?

A. The costs incurred by the Company for development and implementation of NWAs during the Rate Plan, including the overall pre-tax rate of return on such costs, should be recovered in accordance with the detailed accounting procedure established and filed in compliance with the Commission's July 15, 2016 Order Implementing With Modification The Proposal For Cost Recovery And Incentive Mechanism For Non-Wire Alternative Project within Case 14-E-0318 ("NWA Order"). The Company also proposes that the development costs associated with the initial NPAs be funded through R&D as described in the testimony of the Gas Safety Panel and any incremental implementation costs would be deferred and recovered through the RAM. To the extent NWAs or NPAs result in the Company displacing a capital project reflected in the Average Electric or Gas Plant In Service Balances, the balance will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge on the reduction of the Average Electric or Gas Plant In Service Balance that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NWA or NPA. In the event the carrying charge on the net plant of any displaced project is higher than the NWA or NPA recovery, the difference will be deferred for the benefit of customers.

Q. How does Central Hudson propose to earn and recover incentives associated with NWAs and NPAs?

A. The Company will earn incentives for NWA or NPA implementation under the same terms and conditions approved by the Commission within the NWA Order. However, the Company proposes that any future incentives associated with NWAs or NPAs be recovered over a period of one year. The Company proposes to recover any incentives associated with NWAs consistent with the NWA Order and NPAs in the Rate Adjustment Mechanism described by the Accounting and Tax Panel.

Q. Where can additional details on NWAs and NPAs be found?

A. The details on existing NWA projects can be found in the Company's Initial DSIP. The details of the Company's NPA projects can be found in the testimony of the Gas Safety Panel.

VII. ENERGY STORAGE PROJECTS

Q. Please provide an overview of the Company's proposed battery storage projects as required in the Commission's Updated DSIP Order.

A. The Company, in response to the Commission's Updated DSIP Order, has been developing three distinct battery storage projects. Two of the projects are defined as "Storage Assisted Interconnections" and are intended to help support increased integration of DERs, primarily PV, in areas of the system with anticipated high penetration levels that would otherwise require significant upgrades to be funded by developers or would require the output of these facilities to be potentially significantly curtailed absent the upgrades. The third project is defined as "Reliability-Based" and would look to use battery storage as a means to significantly improve the reliability of small pockets of customers that experience a significantly higher numbers of outages as compared to our average customer. The battery storage would improve reliability of service for these customers and would be evaluated as compared to other conventional reinforcement alternatives.

Q. Please provide further details about the Storage Assisted Interconnections projects.

A. The Company is currently evaluating two projects in this category. One project would address anticipated significant constraints in a transmission pocket, and the second where there are significant constraints on a portion of the distribution system. The constrained transmission pocket addressed by the first project is a 69kV transmission loop in the northwest portion of the Company's service territory known as the Westerlo loop. Currently the Company has over 120MW of projects being proposed in this loop between those in the NYISO interconnection queue and the SIR. Based on existing thermal and voltage constraints that exist in this pocket, the amount of PV that can be integrated into the system without significant reinforcements is approximately 20MW or one sixth of the proposed projects. For the distribution system project, the business model and application would be very similar to what was described above. The Company is working to identify potential locations for the distribution Storage Assisted Interconnection project.

Q. How are you proposing that cost for the Storage Assisted Interconnection projects be paid?

A. Since these projects would be installed solely for the benefit of PV developers, the Company is proposing that all costs associated with these Storage Assisted Interconnection projects be paid for by the developers. The costs would be segregated into two parts; the first would be a fixed cost that would be allocated to all developers that are participating and utilizing the storage project. This fixed cost would be allocated on a per kW of nameplate basis and cover up front capital costs of infrastructure that the Company could not reutilize. Since the Company is proposing to use containerized batteries and padmounted transformer and inverters, it would not include the equipment costs but would include the engineering design, permitting, site work, and initial installation in the developers' upfront costs. There would also be an annual charge to developers to cover the return on and return of the equipment costs and ongoing costs including O&M, taxes, and insurance. These costs would be allocated on a per kW of nameplate basis as well. Developers who wanted to participate would need to commit to a 20 year contract for the facility. The Company would manage the battery installation, including charging and discharging, and would likely be able to significantly increase the hosting capacity for these constrained areas. In addition, any incremental market revenues that are realized from operation of the battery storage system; such as the delta of Locational Based Marginal Pricing ("LBMP") between charge and discharge cycle and ancillary services value could potentially be provided back to the developers.

Q. Could you explain how the Reliability-based storage project would work?

A. The Company would identify locations on the system where customers are experiencing a significantly higher number of outages compared to the average customer. It is anticipated that these locations would be relatively small pockets of customers which are likely remote from the substation. We would develop a plan, utilizing services of consultants described below, to use battery storage to improve reliability to these customers. The cost of the storage would be compared to a potential traditional T&D investment and, potentially, the results from an NWA solicitation. Assuming the battery storage project was the least cost alternative it would be installed and managed by the Company. The Company, as part of its evaluation, would consider any additional quantifiable benefits the storage system could provide beyond the reliability improvement. The

Company is working to identify potential locations for the reliability based storage project.

Q. How does the Company propose to implement these projects?

A. The Company is currently working with two consultants in support of its work on these projects. These consultants have expertise in the evaluation and deployment of storage projects. The first step is performing a comprehensive analysis of specific locations and sizes of the systems for each of the three projects to understand what system size is optimal, as well as performing a cost benefit analysis as compared to other potential solutions. It is anticipated that this work will be completed in the early September timeframe. It is proposed that the Company work collaboratively with Staff through this process.

Since it is proposed that the Storage Assisted Interconnection projects be funded by developers, if the developers are not willing to fund these projects they will not be implemented. The Company is requesting that it be allowed to defer for future recovery any incremental development costs for these projects should they not move forward. In regards to the reliability-based storage project, since costs are not yet known, it has not been included in the Company's proposed capital plan. Assuming that this project moves forward, it is proposed that it will be a traditional capital project. As such, the Company would be seeking the authority to defer the full revenue requirement effects of this project.

VIII. REV DEMO PROJECT

Q. Please describe the REV Demonstration Project that Central Hudson is presenting for discussion.

A. Central Hudson is presenting a REV Demonstration Project on Refined Real-Time Pricing ("RRTP") which will test the concepts of granular location pricing at both the Transmission level as well as through the Distribution System. Specifically, this demonstration project will test: 1) the Company's ability to provide this granular pricing in near real time to customers and to gauge the response of customers to this price information; 2) the development of information to inform potential real-time rate designs; and 3) the development of a process to calculate the impact of location on the value of DER.

Q. How does Central Hudson propose to recover costs associated with the project?

A. If the Commission determines that Central Hudson should, in concert with Staff, fully develop and implement all or any portion of the project, through the REV Demonstration Project process, Central Hudson will file for cost recovery of this project through the existing REV Demonstration Project process.

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Q. Please describe the goals of the RRTP Demonstration Project.

A. The Project on Refined Real-Time Pricing would be designed to:

- Take advantage of the existing NYISO project to provide Locational Based Marginal pricing for many more Transmission Nodes at a near real time frequency, also called Sub-Zonal pricing.
- Analyze this NYISO Sub-Zonal pricing to assess the price differences between Transmission Nodes, to develop an understanding of the cause, frequency, magnitude, and pervasiveness, of price differences between transmission nodes and in the sub-transmission and distribution system to inform:
  - Optimizing the operation of the sub-transmission and distribution system.
  - Developing new beneficial locations based on real time price differentials.
- Refine the current process to calculate granular distribution pricing and potentially provide a more accurate locational value to DER.
- Assess the Impact on System Load of more granular pricing through both measurement and developing an understanding of the underlying mechanics/customer processes that would lead to that impact.

Q. What customers would be eligible for this project?

A. The Company would select one or more large commercial or industrial customers whom are located in specific areas of the Central Hudson system. These locations would be served by different Transmission Nodes and different distribution circuits for which the NYISO provides Locational Based marginal pricing. The customers will be selected based on their willingness to respond to real-time price signals and to provide information on this response.

Q. Can you provide information that might be useful to further develop the Project on Refined Real-Time Pricing?

A. Yes. The following is information that Central Hudson has developed around this program:

- Customer identification;
    - Central Hudson intends to offer this demonstration project to a few specifically located large Commercial or Industrial customers.
- Locations;
    - These will be customers who 1) are mapped to different Transmission Nodes, 2) are located on distribution circuits identified within the Marginal Cost of Avoided Transmission and Distribution study filed within the DSIP

and 3) are willing and capable of adjusting their load or DER in response to real time pricing.

- Research Partners;
    - Other than utilizing the information provided by the NYISO from their REV project, we will be partnering with two vendors on this project: one to perform Transmission Node LBMP data analysis and the other to help to target and coordinate the customer relationship in the project, develop the locational pricing and value of DER at the distribution level within the circuit, and analyze customer response to real-time price signals.
- Scope;
    - Develop the ability to calculate Distributed Locational Marginal Prices ("DLMP") and Locational Value of DER for the feeders selected.
    - Develop an RRTP rate design that will reflect the DLMPs.
    - Estimate the likely load response of customers to the RRTP rate design.
    - Test the proposed RRTP rate design (with customer safeguards) and track the benefits to the participating customers (and potentially to other customers located on the pilot feeders).

  - Measure the benefits to the Company from the pilot and estimate the benefits that would accrue if RRTP was implemented at full scale
  - Provide a report documenting the pilot.
- Schedule;
  - The project will be performed over a two year period, with the first year primarily focused on customer recruiting, design, and set-up and the second year spent on testing and validation.
- Rate Design;
  - For this project, Central Hudson does not propose to alter the way that the participating customers will be charged for their electric use, but rather to develop a shadow rate design based on the real time pricing principles and provide this data to the customers.
- Learnings;
  - There are two major learnings expected from this project. The first is a method to calculate and measure the economic value of real energy and reactive power from DERs (products) by hour by node on a feeder, to provide the economic data needed to justify utility investments in measures such as storage, and to provide an

assessment of the economic limitations of feeders which complements knowledge of the physical limitations.

- o The second learning is the ability of customers to react to real time locational pricing and our ability to estimate their response to this pricing.

Q. Why is the Company bringing forward these preliminary program proposals as part of its delivery rate filing?

A. Central Hudson is committed to working with Staff, the Commission, and a wide range of stakeholders to deliver and facilitate new value added energy proposals in the REV proceedings, which are moving forward contemporaneously with these cases. The Company is also committed to working with Staff and interested parties to further develop these proposals during the pendency of these cases.

Q. Does this conclude the Panel's direct testimony at this time?

A. Yes, it does.