EXHIBIT JC-5

BEFORE THE

NEW JERSEY BOARD OF PUBLIC UTILITIES

**IN THE MATTER OF THE PETITION OF
JERSEY CENTRAL POWER & LIGHT COMPANY PURSUANT TO
N.J.S.A. 40:55D-19 FOR A DETERMINATION THAT THE
MONTVILLE - WHIPPANY 230 KV TRANSMISSION PROJECT IS
REASONABLY NECESSARY FOR THE SERVICE, CONVENIENCE
OR WELFARE OF
THE PUBLIC**

Direct Testimony

of

Paul F. McGlynn

Re: PJM Transmission Planning Process and Electric Need for the Project

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Paul F. McGlynn, and my business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497.

Q. By whom are you employed and in what capacity?

A. I am employed by PJM Interconnection, L.L.C. ("PJM"), a regional transmission organization ("RTO"), as a Senior Director in the System Planning Division. I am testifying on behalf of Jersey Central Power & Light Company ("JCP&L") in this proceeding.

Q. Please describe your professional experience and educational background.

A. I am employed by PJM as Senior Director of the System Planning Division. In that position, I am responsible for all aspects of the transmission planning analysis conducted by PJM. My responsibilities include assessing long-term transmission system adequacy and reliability to recommend bulk transmission system expansion or enhancement options; integrating the results of the base line reliability analysis with the market efficiency and generation and merchant transmission interconnection analyses into the overall Regional Transmission Expansion Plan ("RTEP") for PJM; and managing the System Planning Division analytical staff. I serve as Chair of the PJM Transmission Expansion Advisory Committee ("TEAC").

Prior to joining PJM, I was employed by PECO Energy for 21 years where I began work as an Engineer in the Electrical Engineering Division. I was promoted to manager of Engineering in Transmission and Substations in 1995. I transferred to System Operation in the Operations Planning Department in 1998. I was promoted to Shift Manager in System Operations in 1999 and to Manager in Operations Planning in 2001. I became Manager in Transmission Control in 2003.

At PECO, I was responsible for the engineering and design of transmission and substation equipment, including protective relay systems; providing engineering and technical support of PECO's transmission and substation organization; short-term transmission system planning studies, developing operating procedures and preparing and presenting training courses; directing the real-time operation of the Transmission System; short-term transmission planning, outage coordination, dispatcher training, procedure development and real-time control room support; and managing the real-time personnel and activities of the transmission control center.

Q. What is your educational background?

A. I hold a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University and a Master of Science degree in Electrical Engineering from Drexel University.

Q. Do you have any professional licenses and certifications?

A. Yes. I am a licensed Professional Engineer in the Commonwealth of Pennsylvania.

Q. Have you previously testified before the New Jersey Board of Public Utilities ("BPU")?

A. Yes. I have testified before the New Jersey Board of Public Utilities related to the Susquehanna to Roseland 500 kV line (BPU Docket No. EM09010035), the North Central Reliability Project (BPU Docket No. E011050323), and the McCarter Road Switching Station (BPU Docket No. E014020185).

II. <u>PURPOSE OF TESTIMONY</u>

Q. Please describe the purpose of your testimony.

A. I have been asked by JCP&L to explain the electric need for the Montville - Whippany 230 kilovolt ("kV") Transmission Line Project (the "Project") from PJM's perspective.

Q. What, in summary, is the subject matter of your direct testimony?

A. PJM is the RTO that manages an open regional planning process under federal regulation in thirteen states and the District of Columbia including the JCP&L system in New Jersey. The process, referred to as the RTEP, recognizes several distinct needs for transmission expansion including:

1. Reliability;
2. Market Efficiency;
3. Operational Performance;

4. Public Policy Requirements; and

5. The ability to address congestion.

The Project is needed to resolve expected future violations of reliability standards. The purpose of my testimony is to explain that need and describe the planning process that identified and confirmed it.

Q. Are you sponsoring any Exhibits?

A. No.

III. DESCRIPTION AND OVERVIEW OF PJM

Q. What is PJM?

A. PJM is a Regional Transmission Organization regulated by the Federal Energy Regulatory Commission that is responsible for the planning, operation, and reliability of the interstate electric transmission system under its functional control which spans 13 states and the District of Columbia.[1] PJM coordinates the movement of wholesale electricity on and across that grid. The PJM system serves approximately 60 million customers, and PJM dispatches more than 185,000 megawatts ("MW") of generation capacity over more than 65,000 miles of transmission lines. In total, the PJM system serves and supports approximately 20 percent of the United States economy.

[1] The PJM Region includes all or parts of Delaware, the District of Columbia, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The PJM Region and its transmission zones are shown in Attachment J to the PJM Tariff.

PJM presently has more than 900 members. These members, who in many cases are also customers of PJM, include power generators, transmission owners ("TOs"), electricity distributors, power marketers, and large consumers. PJM has no financial or ownership interest in any PJM member, including FirstEnergy. PJM's role as a federally-regulated RTO means that it acts independently and impartially in operating and planning the regional transmission system and in overseeing the wholesale electricity market.

Q. What is the basis for PJM's authority to carry out its responsibilities?

A. As a FERC-approved RTO, PJM is, among other things, responsible to ensure the reliability of the transmission grid in the PJM Region. PJM's authority with respect to its planning process is based on its role as a FERC-approved RTO and on its authority and responsibilities under the PJM Operating Agreement, the PJM Tariff, and the PJM Consolidated Transmissions Owners Agreement ("CTOA"), each of which has been filed at and approved by FERC.

PJM also implements other standards and regulations. For example, FERC has approved the NERC[2] Reliability Standards, and PJM plans and operates the transmission system to those standards. PJM is also designated by NERC as the Planning Coordinator (formerly called Planning Authority) and the Transmission Planner with respect to compliance with the NERC standards. In so doing, PJM applies reliability requirements and standards adopted by NERC,

[2] The North American Electric Reliability Corporation ("NERC") is the electric reliability organization for North America. Regulated by the Federal Energy Regulatory Commission and Canadian authorities, it develops and enforces Reliability Standards; annually assesses reliability; monitors the bulk power system; and educates, trains, and certifies industry personnel. *See* www.nerc.com.

regional reliability organizations, as well as standards promulgated by transmission owners. PJM's authority to carry out its responsibilities is established by FERC's approval of the PJM's governing agreements, its approval of the NERC Reliability Standards, and PJM's designated roles with respect to those standards.

Q. What benefits do members derive from PJM membership?

A. PJM continues to operate and plan the transmission system as though it were a single system. Corporate and state boundaries are not considered when taking operational action or making planning decisions. Considerable benefits accrue to the PJM members and their customers through PJM's centralized security-constrained economic dispatch of resources to meet load (typically generation), reserve requirements, and coordinated planning. These activities are estimated to produce as much as $2.2 billion per year in benefits and economic value for the region PJM serves.

IV. PJM TRANSMISSION PLANNING FUNCTION

Q. What is PJM's role in transmission planning?

A. As part of its ongoing responsibilities as an RTO, PJM prepares the RTEP each year in order to analyze the transmission and electric supply needs of the customers in the PJM region. The RTEP addresses near-term system needs, market efficiency, and transmission expansion options requiring a planning horizon of 15 years. The RTEP provides forward-looking information as to the state of the supply and delivery infrastructure and identifies future system needs, both in terms of reliability and market efficiency. Among other things, the RTEP can direct PJM's TO members[3] to install transmission facilities or undertake other transmission projects. Additionally, the information publicly disseminated through the RTEP process gives other resource providers, including generators and demand response providers, the opportunity to address identified system needs in a manner that might delay or even obviate the transmission solution first identified in the RTEP.

Q. What is the basis of PJM's transmission planning function?

A. PJM's authority and obligation to perform this function is established in the PJM Tariff and related agreements. The process is overseen by the PJM Board and regulated by the Federal Energy Regulatory Commission ("FERC").

V. RTEP PROCESS

Q. Does PJM have a written protocol for its planning process?

A. Yes. The RTEP Protocol and PJM's role in transmission planning in the PJM Region are set forth in Schedule 6 of the PJM Operating Agreement. The purpose and objective of Schedule 6 is stated as follows:

[3] A PJM member becomes a TO member of PJM when it owns "Transmission Facilities" and becomes a signatory to the Consolidated Transmission Owners Agreement ("CTOA"). Under the PJM Operating Agreement, a "Transmission Owner" is a PJM member that owns Transmission Facilities or leases Transmission Facilities with rights equivalent to ownership and is a signatory to the CTOA. PJM Operating Agreement, effective August 22, 2013, Section 1.45. "Transmission Facilities" means facilities that (i) are within the PJM Region, (ii) meet the definition of transmission facilities pursuant to FERC's Uniform System of Accounts or have been classified as transmission facilities in a ruling by FERC addressing such facilities, and (iii) have been demonstrated to the satisfaction of PJM to be integrated with the PJM transmission system and integrated into the planning and operation of the PJM transmission system to serve all of the power and transmission customers within the PJM Region. PJM Operating Agreement, effective October 10, 2013, Section 1.44. Under the CTOA, a PJM member cannot become a signatory to the CTOA until it has Transmission Facilities in service and meets other CTOA requirements.

> This Regional Transmission Expansion Planning Protocol shall govern the process by which the Members shall rely upon the Office of the Interconnection to prepare a plan for the enhancement and expansion of the Transmission Facilities in order to meet the demands for firm transmission service, and to support competition, in the PJM Region. The Regional Transmission Expansion Plan (also referred to as "RTEP") to be developed shall enable the transmission needs in the PJM Region to be met on a reliable, economic and environmentally acceptable basis.[4]

This protocol goes on to describe the requirements for the RTEP to conform with NERC and other applicable reliability criteria, the committee structure to be put in place for stakeholder participation in the development of the RTEP, the contents of the RTEP, the procedures used to develop the RTEP, the process of approval of the RTEP by the PJM Board, the obligation of TOs to build upgrades included in the RTEP, and the treatment of interregional transmission upgrades. The planning process is further described in extensive detail in the PJM Manuals. Overall, the process of developing the RTEP is highly collaborative and provides an open and inclusive forum for participation by all classes of market participants and stakeholders.

Q. What are the primary elements of PJM's regional planning process?

A. The RTEP process integrates transmission, generation and demand-side resources to address transmission system constraints involving reliability and persistent economic congestion. The result is a process that integrates many system factors, including:

1. Forecasted load growth, demand-side-response efforts and distributed generation additions;

[4] PJM Operating Agreement, effective October 10, 2013, Schedule 6, Section 1.1.

2. Interconnection requests by developers of new generating resources and merchant transmission facilities;

3. Solutions to mitigate persistent economic congestion and to ensure adequate allocation and funding of long-term financial transmission rights;

4. Assessments of the potential risk of aging infrastructure;

5. Long-term firm transmission service requests;

6. Generation retirements and other deactivations;

7. TO-initiated improvements; and

8. Load-serving entity capacity plans.

This process narrows the projects that the RTEP recommends as a solution to the PJM Board to various transmission system constraints. The PJM Board will then use its authority pursuant to its tariff to order that a project be constructed or removed.

Q. Does PJM coordinate transmission planning with neighboring systems?

A. Yes. PJM coordinates its planning processes with neighboring RTOs and non-RTO system operators to address issues of mutual concern. PJM participates in such interregional planning under arrangements with the Midcontinent Independent System Operator ("MISO"), the Independent System Operator of New England, the New York Independent System Operator, the Tennessee Valley Authority, and Progress Energy.

Q. Does the RTEP process involve stakeholders and others outside of the PJM organization and the utility serving the area?

A. Yes. The RTEP process is open, transparent and collaborative from start to finish. Forums and processes provide opportunities for stakeholders to help PJM improve the transmission grid, ensuring reliability and access to robust, competitive markets. The process includes an advisory committee, the TEAC that provides advice and recommendations to aid in the development of the RTEP Plan. TEAC, along with additional Sub-regional RTEP Committees, provide a functional forum for the ongoing exchange of ideas, discussion of issues and presentation of planning findings.

The TEAC operates under specific provisions of the PJM Operating Agreement. TEAC activities are at the core of stakeholder input in the RTEP process. The scope of the TEAC's responsibility includes the review of and the provision of comments and input on the following:

- Scope and assumptions of RTEP studies, including the review of PJM's identification of reliability violations and its economic/market efficiency analysis;
- RTEP analysis at defined points during the RTEP cycle;
- RTEP recommendations to be proposed to the PJM Board for approval; and
- The RTEP process, as requested by the PJM Board.

TEAC participation is open to all PJM members, all transmission customers, any other entity proposing to provide transmission facilities to be integrated into the PJM region, representatives of state commission, the agencies and offices of state consumer advocates of states in the PJM region, and any other interested parties. The process fosters broad participation by constituents expressing a wide range of opinions, comments, and advice on RTEP development and recommendations to the PJM Board. Following the presentation of analysis assumptions or results to the TEAC, stakeholders are also invited to provide written comments. These comments are provided to the PJM board for their consideration and serve as the basis for on-going dialogue at subsequent TEAC meetings.

Q. After the process is complete, how is the RTEP approved?

A. The final RTEP is approved by the PJM Board. The PJM board is made up of 10 members that are responsible for maintaining PJM's independence and, by exercising their prudent business judgments, ensuring that PJM fulfills its business obligations and legal and regulatory requirements. Members of the PJM Board may have no personal affiliation or ongoing professional relationship with, or any financial stake in, any PJM market participant. Approval for the current Project, and historical projects, has always occurred through a consensus of the PJM Board members.

Q. For context, can you summarize the nature and extent of the RTEP projects ordered by the PJM Board since the inception of the RTEP process?

A. More than $26 billion of transmission upgrades and additions, representing over 3,000 distinct transmission projects ranging from 69kV to 765kV, have been authorized by the PJM Board from the inception of the RTEP process in 1999 through October 2013. In the current RTEP, about $22 billion of baseline transmission network upgrades across PJM are designed to ensure that compliance with applicable regional and NERC Reliability Standards will continue to be met.

VI. <u>DETERMINATION OF NECESSARY EXPANSION</u>

Q. How does PJM determine whether there is a need for a new transmission facility sufficient to support its inclusion in the RTEP?

A. A proposed project must meet one or more specific criteria to be included in the RTEP. These criteria include.

1. Reliability standards. The RTEP must "conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, RFC, and SERC, and those of the transmission owners in accordance with the planning and operating criteria and other procedures detailed in the PJM Manuals."[5]

2. Operational performance. PJM can act when difficult, complex, or restrictive operating actions (*e.g.*, excessive switching, complex or limiting protection schemes) are required to meet minimum reliability criteria.[6]

[5] Section 1.2(d) of Schedule 6 to the PJM Operating Agreement.

[6] Section 1.5.3(d) of Schedule 6 to the PJM Operating Agreement.

3. Feasibility of congestion management. PJM uses a pricing system to manage congestion. Transmission facilities must be built as required to maintain feasibility of Stage 1A Auction Revenue Rights, a key feature of this system.[7]

4. Market efficiency. If new facilities can lower costs to customers, and benefits of the project exceeds its costs, then PJM can require new transmission to be built. There are strict metrics governing market efficiency projects and in PJM the benefit to cost ratio must be greater than or equal to 1.25.[8]

Finally, the RTEP also includes enhancements required as a result of coordination with other planning regions.[9]

Q. On what basis did PJM through the RTEP process determine that the Project was necessary?

A. The Project is necessary to satisfy reliability criteria.

VII. <u>ROLE OF FERC AND NERC</u>

Q. Please explain the role of FERC and NERC in addressing transmission reliability.

A. Historically, compliance with Reliability Standards developed by NERC was considered voluntary. The Energy Policy Act of 2005 ("EPAct 2005"), however,

[7] Section 1.5.3(h) of Schedule 6 to the PJM Operating Agreement.

[8] Section 1.5.7(d) of Schedule 6 to the PJM Operating Agreement.

[9] Section 1.5.5 of Schedule 6 to the PJM Operating Agreement.

enacted after the 2003 Blackout, established a mandatory compliance and enforcement regime for Reliability Standards under the oversight of FERC. Pursuant to EPAct 2005, FERC designated NERC as the "Electric Reliability Organization" for the United States and NERC then proposed various Reliability Standards, most of which have been approved by FERC. Mandatory compliance with NERC Reliability Standards began on June 18, 2007. Failure to comply with the FERC-approved Reliability Standards may result in penalties as high as $1 million per violation per day.

Q. Please explain NERC criteria applicable to transmission planning.

A. Mandatory reliability standards developed by NERC, and approved by FERC, are used by transmission planners to measure the need for new transmission lines or upgrades to existing lines. NERC Reliability Standards TPL-001, 002, and 003 each require that PJM perform assessments to demonstrate compliance with planning standards over both the near term (1 – 5 years) and longer term (6 – 10 years). Those standards also require that, when PJM's simulations identify an inability of the system to respond as required, PJM must develop a schedule for implementation and in-service dates for plans to achieve required system performance throughout the planning horizon, taking into account the lead times necessary to implement those plans. In addition, transmission owners and PJM have developed planning reliability criteria to supplement the NERC Reliability Standards. The NERC Reliability Standards and the transmission owner and PJM planning reliability criteria (collectively, "Reliability Standards") were the criteria used to determine that the Project is needed to prevent electric reliability problems from occurring.

PJM tests for compliance with all reliability criteria imposed through the NERC Planning Standards TPL-001 through TPL-003. The NERC Reliability Standards require that PJM identify the "critical system conditions" that the system must be evaluated against to ensure that it meets performance criteria. PJM establishes the critical system conditions through the application of specific procedures documented in PJM Manual 14B.

Q. How specifically does PJM conduct an analysis of whether upgrades are needed to satisfy NERC Reliability Standards?

A. With the critical system conditions established, the NERC Reliability Standards require PJM to test various types of events to ensure that the system meets performance criteria. These types of events fall into three categories: A, B, and C. NERC Category A criteria require that, for all facilities in service, equipment thermal ratings and system voltage limits are respected and that the system is stable. NERC Category B criteria impose similar requirements with one facility removed from service. This is referred to as the "n minus 1" or "n-1" criteria. These criteria ensure that the system continues to remain reliable upon the instantaneous outage of a generator or transmission system element.

NERC Category C criteria require the system to be stable and within applicable equipment thermal ratings and system voltage limits during second contingencies, that is the loss of one system element followed by system readjustments, and then the loss of a second system element. This is referred to as the “n minus 1 minus 1” or “n-1-1” criteria. As I will describe later, the violations driving the need for the Project are n-1-1 violations, also known as NERC Category C violations. Category C also includes events such as the loss of two circuits on a single tower line or a single faulted system element followed by a circuit breaker failing to operate, which is referred to as a stuck breaker.

VIII. ELECTRIC NEED FOR THE PROJECT

Q. Describe the Project.

A. The Project is to construct a new 230 kV line between the JCP&L’s Whippany substation in East Hanover Township, Morris County and the Montville substation in Montville Township, Morris County along with the associated modifications to those substations. Mr. Hozempa provides a more detailed description of the project in his direct testimony.

Q. Did you have a role in determining the electrical need for the Project?

A. Yes. In my role as PJM’s Sr. Director of System Planning, I supervised the creation of the base cases for the 2012 RTEP that determined the need for the Project.

Q. What studies did you perform or supervise the performance of as Sr. Director System Planning that determined the need for the Project?

A. I supervised all of the analyses conducted as part of the 2012 RTEP including model development, identifying reliability criteria violations, and formulating solutions to violations.

Q. What role did JCP&L have with regard to those studies?

A. JCP&L provided electrical model data for the JCP&L transmission zone within PJM and the contingency files used in the analysis. In addition, JCP&L reviewed the model once it was created by PJM. JCP&L worked closely with my staff at PJM in validating the reliability criteria violations and formulating the solution to the violations. In addition, as described in Mr. Hozempa's direct testimony, JCP&L performed dynamic analyses to determine the extent of the impact on the underlying 34.5 kV system around Montville substation.

Q. What conclusions were reached as a result of those studies?

A. The 2012 RTEP baseline analysis identified voltage related violations of NERC Reliability Standards. PJM identified voltage collapse conditions for the outage of the Montville – Roseland (E2205) 230 kV line followed by the loss of the Kittatinny – Newtown (T2298) 230 kV line. In addition PJM identified voltage collapse conditions for the outage of the Montville – Roseland (E2205) 230 kV line followed by the Newton – Montville (N2214) 230 kV line. These are considered NERC Category C (N-1-1) events as described previously in my testimony. In addition, JCP&L performed analysis of the impact of the loss of the facilities noted above on underlying distribution systems which identified that over 400 MW of load would be lost which is also a violation of PJM planning criteria.

Q. What alternatives were considered for the project?

A. As described by Mr. Hozempa in his direct testimony, in addition to the new Montville – Whippany 230 kV line, consideration was given to building a new Montville to Whippany 115 kV line. This alternative was ultimately dismissed because: (i) the Montville substation presently does not have any 115 kV facilities; therefore, a new 115 kV yard would need to be developed and a 230/115 kV transformer would need to be installed at Montville substation; and (ii) the 115 kV facilities at Whippany substation are not presently designed for an additional 115 kV circuit so the 115 kV yard would need to be expanded. For the above reasons, the alternative is more complicated and costly to construct.

Q. Has PJM re-assessed the need for the Project in subsequent RTEP analyses?

A. Yes, PJM completed two re-assessments of the need for the Project. First, PJM completed an initial re-assessment of the need for the Project based on the updated load forecast that was being used as part of the 2013 RTEP. PJM completed another re-assessment of the need for the Project based on the updated load forecast that is being used as part of the 2014 RTEP. The power flow case used to identify the violations in the 2012 RTEP was updated with the 2013 and 2014 load forecast. The results of these re-assessments were consistent with the conclusions of the need reached in 2012. Specifically, the voltage collapse conditions were observed at the same stations as the 2012 RTEP. PJM will complete another re-assessment later in 2015.

Q. Is it prudent to move forward with the Project at this time?

A. Yes, it is. It is highly unlikely that the 2015 reassessment will change the outcome identified in the 2012 RTEP. Our initial assessment identified a potential voltage collapse risk on the system in the Greystone, Montville, Riverdale and Whippany areas with a potential loss of load exceeding 400 MW resulting from the NERC Category C contingency.

Q. Under what conditions are demand response programs integrated into the development of the RTEP?

A. Demand response ("DR") programs are integrated into the development of the RTEP when they clear in an RPM auction and take on a forward commitment to provide service in a future planning year. Such programs, however, are only modeled in circumstances where they would expect to be enacted in day-to-day operations. Specifically, DR programs can only be enacted during operational emergency conditions and is typically done at a zonal level.

Q. Did PJM consider the availability of DR in evaluating the need for the Project?

A. Yes, it did. Only DR Programs implemented in the specific Montville/Whippany load pocket will have any effect on the need for the Project. Demand response providers are not required to notify PJM of the specific load that will be curtailed until the month preceding the start of the delivery year. Although there is no guarantee it will be available in 2017, historically there has only been approximately 2 MW of DR in this area, which is not enough to have a meaningful impact on the need for the Project.

IX. CONCLUSION

Q. Does this conclude your direct testimony

A. Yes.