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PUC LATE-FILED EXHIBITS

Docket No. A-110172

Hearing Date March 25, 2008

Judge Nemec / Hoyer

Hearing held in Pittsburgh

Exhibit No. See attached

Reporter John Kelly

1. Above exhibit to be supplied to reporter by:

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2. Above exhibit to be filed directly with PUC by:

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Additional Comments:

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NUMBER	FOR IDENTIFICATION	IN EVIDENCE
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4 (Gass - Direct, with Exhibits SWG-1 through Exhibit SWG-3)	2517	2519
4-R (Gass - Rebuttal)	2517	2519
4-RJ (Gass - Rejoinder, with Exhibits SWG-RJ-1 and SWG-RJ-2)	2517	2519
OCA Cross-Examination Exhibit		
3 (PJM Required Projects for Allegheny Power 2005-2011)	2531	2548
4 (critical congestion map)	2544	2548
5 (US DOE Draft, National Corridor Designations: Key Findings and Conclusions)	2546	2548
ECC Cross-Examination Exhibit		
1 through 3 (previously marked)	--	2499
4 (excerpt, Herling rebuttal in West Virginia, 07-0508-E-CN)	2402	2499
5 (response, ECC-III-2)	2402	2499
6 (6/23/06 ESH Meeting, PowerPoint presentation)	2404	2499
7 (Generator Deliverability Results for Category 3 Generation in Dominion)	2414	2499
8 (response, PEC-II-62)	2419	2499
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9 (Mt. Storm-Doubs 500 kV line rating information)	2426	2499

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19 (2006 RTEP report, Section 4, page 150)	2452	2499
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26 (response, ECC-VII-26)	2559	--
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TrAILCo Statement No. 4
Witness: Scott W. Gass

Pgh JK
3/25/08

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION A-110172

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY FOR (I) A CERTIFICATE OF PUBLIC CONVENIENCE TO OFFER, RENDER, FURNISH AND/OR SUPPLY TRANSMISSION SERVICE IN THE COMMONWEALTH OF PENNSYLVANIA; (II) AUTHORIZATION AND CERTIFICATION TO LOCATE, CONSTRUCT, OPERATE AND MAINTAIN CERTAIN HIGH VOLTAGE ELECTRIC TRANSMISSION LINES AND RELATED ELECTRIC SUBSTATION FACILITIES; (III) AUTHORITY TO EXERCISE THE POWER OF EMINENT DOMAIN FOR THE CONSTRUCTION AND INSTALLATION OF AERIAL ELECTRIC TRANSMISSION FACILITIES ALONG THE PROPOSED TRANSMISSION LINE ROUTES IN PENNSYLVANIA; (IV) APPROVAL OF AN EXEMPTION FROM MUNICIPAL ZONING REGULATION WITH RESPECT TO THE CONSTRUCTION OF BUILDINGS; AND (V) APPROVAL OF CERTAIN RELATED AFFILIATED INTEREST ARRANGEMENTS	:	Docket Nos. A-110172 A-110172F0002 A-110172F0003 A-110172F0004 G-00071229

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DIRECT TESTIMONY OF SCOTT W. GASS

Re: Electrical Need for TrAIL

April 13, 2007

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott W. Gass and my business address is 15 Shannon Way, Royersford, Pennsylvania 19468.

DUTIES AND RESPONSIBILITIES

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by PowerGEM as a Principal Consultant.

Q. PLEASE DESCRIBE POWERGEM.

A. PowerGEM was founded in May 2000 to provide expert advice, analysis, and software addressing the economic and technical impacts of transmission congestion in competitive electricity markets.

EXPERIENCE AND EDUCATION

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from Pennsylvania State University in 1987 with a Bachelor of Science in Electric Engineering. In addition, I completed a two-year power system operations and planning course provided by Power Technologies, Inc. in 1989.

Upon graduation from Pennsylvania State University, I joined GPU Energy in June 1987. At GPU Energy, I was involved in transmission, sub-transmission and distribution planning where I analyzed current and future infrastructure to optimize system utilization and to ensure adequate and reliable service to customers. I also completed operating studies to provide dispatchers

with expected problem areas and solutions. As a direct result of my work, I have extensive experience with Mid-Atlantic Area Council reliability criteria, transient analysis, load flow and short circuit analysis.

In October 1998, I joined PJM Interconnection, L.L.C. ("PJM") as a Senior Engineer in Transmission Planning with responsibility for coordinating all generation interconnection and baseline studies, including completion of over one hundred interconnection load flow and short circuit studies. In July 2003, I was promoted to Manager Transmission Planning. In that position, I was responsible for all aspects of the planning analysis conducted by PJM on its transmission system, including the interconnection of new generation to the PJM transmission system; working with transmission owners to develop system enhancements to maintain future reliability of the PJM system; the integration of Allegheny Power, Commonwealth Edison Company, American Electric Power Company, Dayton Power & Light Company, Virginia Electric and Power Company ("Dominion Virginia Power") and Duquesne Light Company into PJM; and managing and mentoring 18 transmission planning engineers.

While at PJM, I represented PJM on numerous stakeholder committees, including the Regional Planning Process Working Group, the Reliability Planning Criteria Working Group, the Planning Committee, the Economic Planning Implementation Working Group, the Transmission Expansion Advisory Committee and two Inter-Regional Planning Stakeholder Committee efforts, one with the Independent System Operator of New England ("ISO-NE") and New York Independent System Operator and the other with the Midwest Independent

Transmission System Operator. In addition, I was involved in the development and implementation of multiple standards and procedures followed by PJM including, among others, the generation and merchant transmission interconnection processes, the generation and load deliverability procedures, PJM planning criteria, and cost allocation procedures for both baseline and network upgrades for interconnection projects. I was also responsible for completing the studies associated with the extension of the PJM planning horizon in 2006 from five years to 15 years.

In November 2006, I joined PowerGEM as a Principal Consultant. My work responsibilities have included completion of fatal flaw studies for potential generation interconnection projects and the development of a Minimum Interconnection Standard test and procedure for application in the recently approved ISO-NE Forward Capacity Market.

PURPOSE OF TESTIMONY

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. I am testifying on behalf of TrAILCo to demonstrate the electrical need for the Prexy Facilities, the 502 Junction Substation and the Pennsylvania 502 Junction Segment of the Trans-Allegheny Interstate Line ("TrAIL"). TrAILCo witnesses Hozempa and Herling are also providing testimony relating to the electrical need for these transmission line segments and the planning process that resulted in the determination of that need.

Q. WILL THE USE OF VARIOUS TERMS IN YOUR TESTIMONY BE CONSISTENT WITH THE DEFINITION ASSIGNED TO THE TESTIMONY OF DAVID E. FLITMAN IN TRAILCO EXHIBIT DEF-1?

A. Yes. In addition, I may define other specific terms in my direct testimony.

EXHIBITS

Q. PLEASE IDENTIFY THE EXHIBITS TO YOUR TESTIMONY.

A. I am sponsoring three exhibits with my direct testimony:

- TrAILCo Exhibit SWG-1 presents the electric reliability problems that will occur if the Pennsylvania 502 Junction Segment is not constructed;
- TrAILCo Exhibit SWG-2 presents the 2006 through 2015 projected summer peak loads for the mid-Atlantic and northern Virginia areas; and
- TrAILCo Exhibit SWG-3 presents the mid-Atlantic area and northern Virginia area historical summer peak loads for 1995 through 2005.

ELECTRICAL NEED FOR THE PREXY FACILITIES

Q. WHAT IS THE ELECTRICAL NEED FOR THE PREXY FACILITIES?

A. Based on system studies, PJM and Allegheny Power concluded that there are four electric reliability problems that will occur beginning in 2009 if the Prexy Facilities are not constructed. These problems are described in TrAILCo Exhibit LAH-3 attached to the direct testimony of TrAILCo witness Hozempa.

Q. DID YOU HAVE A ROLE IN DETERMINING THE ELECTRICAL NEED FOR THE PREXY FACILITIES WHILE WORKING FOR PJM?

A. Yes. In my role as PJM's Manager Transmission Planning, I directed the North American Electric Reliability Corporation ("NERC") Category C3 ("N minus 2" or "N-2") analysis conducted by the PJM transmission owners as part of the 2006 RTEP process for transmission facilities below 345 kV. Each transmission owner was responsible for conducting the analysis for its transmission facilities, reporting any reliability violations to PJM, and proposing solutions to PJM for any potential violations identified.

Q. WHAT STUDIES DID YOU PERFORM OR SUPERVISE AS MANGER TRANSMISSION PLANNING THAT DETERMINED THE NEED FOR THE PREXY FACILITIES?

A. I supervised PJM's validation of the NERC Category C3 (N-2) potential violations identified by the transmission owners and confirmed that the proposed solutions were sufficient to address the potential violations reported by the transmission owners to PJM.

Q. WHAT ROLE DID ALLEGHENY POWER HAVE WITH REGARD TO THESE STUDIES?

A. Allegheny Power performed the NERC Category C3 (N-2) analysis and developed proposed solutions to the potential violations identified. Allegheny Power also notified PJM of the results of its analysis as required as part of the 2006 RTEP process.

Q. WHAT CONCLUSIONS WERE REACHED AS A RESULT OF PJM'S STUDIES?

A. PJM validated the violations discovered by Allegheny Power in the Prexy area and also confirmed the proposed solution. As a result of PJM's review, the solution proposed by Allegheny Power to the potential reliability violations in the Prexy area was incorporated into the 2006 Regional Transmission Expansion Plan ("RTEP") baseline upgrades.

ELECTRICAL NEED FOR THE PENNSYLVANIA 502 JUNCTION FACILITIES

Q. DID YOU HAVE A ROLE IN DETERMINING THE ELECTRICAL NEED FOR THE PENNSYLVANIA 502 JUNCTION FACILITIES WHILE WORKING FOR PJM?

A. Yes. In my role as PJM's Manager Transmission Planning, I supervised the creation of the base case for the 2011 RTEP and the power system studies that determined the need for the 502 Junction Substation, the 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion. The Pennsylvania 502 Junction Facilities consist of the 502 Junction Substation and the portion of the 502 Junction Segments that TrAILCo proposes to construct in Pennsylvania. Although I will be referring to the need for the Pennsylvania 502 Junction Facilities, the need for those facilities is the same as the need for the remainder of the 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion.

Q. WHAT STUDIES DID YOU PERFORM OR SUPERVISE THE PERFORMANCE OF AS MANAGER TRANSMISSION PLANNING THAT DETERMINED THE NEED FOR THE PENNSYLVANIA 502 JUNCTION FACILITIES?

A. I supervised all of the analyses conducted with the 2011 RTEP case, including model adjustments, identifying reliability criteria violations, and formulating solutions to the violations. Specifically with regard to the electrical need for the Pennsylvania 502 Junction Facilities, the remaining 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion, I supervised the generator deliverability, load deliverability and NERC Category C studies.

Q. WHAT ROLE DID ALLEGHENY POWER HAVE WITH REGARD TO THESE STUDIES?

A. Allegheny Power provided the electrical model data for the Allegheny Power transmission zone of PJM ("Allegheny Power Zone") and the contingency files used in the analyses. In addition, Allegheny Power reviewed the model once it was created by PJM. Allegheny Power worked closely with my staff at PJM in validating reliability criteria violations and formulating the Pennsylvania 502 Junction Facilities, the remaining 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion as the overall solution to the identified violations.

Q. WHAT CONCLUSIONS WERE REACHED AS A RESULT OF THOSE STUDIES?

A. Based on the studies performed by PJM, Dominion Virginia Power and Allegheny Power, PJM concluded that there are 11 electric reliability problems that are likely to occur beginning in 2011 and one electric reliability problem that is likely to occur beginning in 2014 if these facilities are not constructed.

Q. WHAT ARE THOSE ELECTRIC RELIABILITY PROBLEMS?

A. The problems are identified on Chart A attached to my testimony as TrAILCo Exhibit SWG-1. In the same exhibit, Chart B identifies the current ownership of facilities referred to in Chart A.

Q. PLEASE EXPLAIN CHART A.

A. The left column identifies possible electric occurrences or "contingencies" and the right column identifies the electrical result of the occurrence if the occurrence occurs any time after June 2011 for occurrences 1 through 8 and 10 through 12 and after June 2014 for occurrence 9. Using #1 as an example, if there is an outage on Line #572A (e.g. unscheduled due to a storm or equipment malfunction, or scheduled due to the need for maintenance), Line #512 will be called upon to provide back-up transmission capacity. However, due to the growing consumer loads served by these lines, it is projected that by Summer 2011, Line #512 will not have enough capacity to deliver all of the electricity needed by the consumers ordinarily served by the two lines together. As a consequence, while Line #572A is not operational due to the outage, Line #512 will overload. As another example using #10 on Chart A, outages on Line #580

and Line #572B at the same time will cause the 138 kV system voltage level around Meadow Brook Substation to drop below acceptable limits and could lead to a voltage collapse in the area.

Q. CHART A REFERS TO "EMERGENCY RATING," "OVERLOADS" AND "ACCEPTABLE LIMITS." WHAT DO THESE TERMS MEAN?

A. "Acceptable limits" in the context of Chart A refers to the voltage limits that are considered acceptable in the planning and operation of the PJM transmission system. "Emergency rating" refers to the equipment loading limit that should not be exceeded after the outage of other power system equipment. As an example, the loading on Line A should not be above its emergency rating for the outage of Line B. The term "overload" is used to describe the condition when the equipment loading exceeds the applicable rating.

Q. PLEASE EXPLAIN THE CONCEPT OF "ELECTRIC RELIABILITY."

A. "Electric reliability" or "reliability," as used by industry experts, refers to the delivery of electricity to customers in the amounts desired and within accepted standards for the frequency, duration and magnitude of outages and other adverse conditions or events. "Load pockets" are created when a major electric load center (*i.e.*, an area where there is a highly concentrated use of electricity) has too little local generation of electricity relative to its electric load and must import much of its electricity via transmission lines from neighboring regions. Because it is very difficult to site and build new generation within an urban area, these areas become load pockets. As a result, transmission lines delivering electricity into the load pocket from distant generating plants will often experience reliability

problems. In other words, these lines become "overloaded" and do not have the capacity to deliver to the load pocket as much electricity as is needed to meet consumer demand. Reliability problems occur when the lines become overloaded. Importantly, these reliability problems are not limited to the load pockets themselves; frequently they can adversely affect the areas surrounding the transmission facilities needed to carry that generation to the load pockets.

Q. HOW ARE RELIABILITY PROBLEMS AVOIDED?

A. New or upgraded transmission lines must be constructed before the reliability problems occur. Alternatively, new generating plants can be constructed within the load pocket, or consumers can reduce their demand. As indicated previously, it is very difficult to build a new generating plant in an urban area. Because demand reduction initiatives are largely voluntary – making mandatory compliance problematic – they cannot guarantee the mitigation of the relevant reliability risks. Thus, even if demand reduction is being encouraged and new generation is being explored, construction of new or upgraded transmission lines is often essential to prevent identified reliability problems from occurring while those alternatives are pursued and to account for the probability that those alternatives will not materialize in sufficient quantity to eliminate the reliability problem. However, transmission planning is not a "one time" activity. Instead, it is dynamic and involves an ongoing review of changes in the transmission system that result from the decommissioning of existing plants, the addition of new plants, changes in load patterns and other events that affect the topology of the transmission system.

Q. HOW DO TRANSMISSION PLANNERS DETERMINE IF, AND WHEN, RELIABILITY PROBLEMS WILL OCCUR IF CORRECTIVE ACTION ON THE TRANSMISSION SYSTEM IS NOT TAKEN?

A. NERC has been designated by the Federal Energy Regulatory Commission ("FERC") as the Electric Reliability Organization for the United States. 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. In addition, transmission owners and PJM have developed planning reliability standards to supplement the NERC reliability standards. The FERC, transmission owner and PJM planning reliability standards (collectively, "Reliability Standards") were the criteria used to determine that the Pennsylvania 502 Junction Facilities, as parts of the overall reliability solution, are needed to prevent these electric reliability problems from occurring.

Q. HOW ARE THE RELIABILITY STANDARDS USED TO DETERMINE WHEN NEW TRANSMISSION LINES OR UPGRADES TO EXISTING LINES ARE NEEDED?

A. PJM, in conjunction with transmission owners such as Allegheny Power, conducts studies of the PJM transmission system that apply the Reliability Standards to specific conditions on the transmission system. When the studies show an inability of the transmission system to meet a specific Reliability Standard under these conditions, construction of one or more new transmission lines or one or more enhancements to existing transmission facilities is necessary.

Q. WHAT TYPES OF STUDIES ARE USED TO DETERMINE IF TRANSMISSION SYSTEM UPGRADES ARE NECESSARY?

One type of study is a Load Deliverability Study. This study examines defined load zones within the PJM region and considers the ability of the transmission system to deliver adequate power to the load zone during a generation capacity emergency. A generation capacity emergency occurs when there is high load (*i.e.*, high consumer demand) on the electric system and insufficient generation capacity within the load zone.

A Generation Deliverability Study is also conducted. This study tests the system to assure that capacity resources can be delivered to the remainder of the PJM system at peak load.

Both types of studies are conducted by simulating the transmission system as it is expected to exist during future time periods. The simulation includes expected load growth (for the load deliverability test this includes the anticipated benefits of demand side management and conservation activities), the addition of new generating plants and the retirement of existing generation plants, and planned transmission construction projects.

Q. WHAT TIME PERIOD WAS CONSIDERED FOR PURPOSES OF THE LOAD DELIVERABILITY AND GENERATION DELIVERABILITY STUDIES ASSOCIATED WITH THE PENNSYLVANIA 502 JUNCTION FACILITIES?

A. The studies supporting the need for these line segments were based on a five-year timeframe, thereby making it critical that the line comprised of these segments be constructed and placed into service by June 2011.

Q. WHAT HAPPENS WHEN A TRANSMISSION LINE OVERLOADS OR EXCEEDS ITS LOADING CAPABILITY?

A. When a transmission line overloads, the conductor, the conductor clamps, and the line terminal equipment begin to overheat. Overheating the conductor may cause the line to sag low enough to bring the line into contact with whatever is underneath it. Under these conditions, the metal in the conductor may become brittle, rendering the line useless. In addition, the line may break and fall to the ground, causing a potentially dangerous situation for those near the line as well as the crews required to respond to the event. Overheating of the conductor clamps and line terminal equipment may cause similar results. In short, overloading transmission lines may cause permanent damage to transmission infrastructure and catastrophic power outages.

Q. WHAT ACTION IS REQUIRED TO PREVENT THESE RESULTS?

A. To prevent the consequences of a potential transmission line overload, immediate action must be taken by system operators before the line or related equipment fails or is permanently damaged. The action may include turning specific generating plants off or on, opening or closing specific transmission lines, or discontinuing electric service to certain customers or groups of customers in specific areas. However, these are emergency and temporary measures only. They prevent a specific breakdown on that occasion, but do not solve the underlying problem. On a long-term basis, construction of one or more new transmission lines or one or more enhancements to existing transmission lines is necessary.

Q. WHAT HAPPENS WHEN THE VOLTAGE DROPS AT A SUBSTATION?

A. The severity of the consequences depends on the severity of the voltage drop at the substation. Voltage drops can occur when large loads are turned on and when faults or short circuits occur on the system. Voltage drops of less than 3% are usually not significant. However, when the voltage drop at a substation exceeds 3%, the consequences can range from annoying dimming of lights in homes and businesses to a voltage collapse.

Q. WHAT HAPPENS WHEN THERE IS A VOLTAGE COLLAPSE ON THE TRANSMISSION SYSTEM?

A. A voltage collapse occurs when the voltage on the system drops to a critically low level and the system is unable to support power transfers across the system and customers' load connected to the system. This condition usually results in a blackout or a brownout. The area affected could be a single community or several communities, or the blackout or brownout could be much more widespread and encompass an entire region.

Q. WHEN TRANSMISSION LINES OVERLOAD, VOLTAGES DROP AT SUBSTATIONS, OR THE VOLTAGE COLLAPSES ON A 138 KV SYSTEM, IS THE RESULT A BLACKOUT LIKE THE ONE EXPERIENCED IN A LARGE PART OF THE EASTERN UNITED STATES AND EASTERN CANADA IN AUGUST 2003?

A. Yes, that is possible. Just before that massive blackout occurred, several transmission lines began to overload due to system conditions. As the overloaded transmission lines were disconnected from the grid, voltage on parts of the

transmission system in the eastern United States and eastern Canada began to collapse, causing generating plants to automatically shut down and additional transmission lines to overload and subsequently disconnect from the grid. This process, often called "cascading," continued until over 50 million people from the east coast to Ohio and north into Canada were without power.

Q. ARE THE PENNSYLVANIA 502 JUNCTION FACILITIES, AS A PART OF THE OVERALL RELIABILITY SOLUTION YOU HAVE DESCRIBED, NECESSARY TO HELP AVOID THIS TYPE OF BLACKOUT FROM OCCURRING AGAIN?

A. Yes. These facilities, along with the remainder of the 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion, will significantly enhance the electric reliability of a major portion of the eastern United States, particularly the area from northern Virginia to northern New Jersey. It will also help to relieve the possibility of outages to the west of the Allegheny Mountains, including the service territory of Allegheny Power in southwestern Pennsylvania.

Q. PLEASE IDENTIFY AND DESCRIBE THE RELIABILITY STANDARDS THAT WILL BE VIOLATED BY EACH OF THE RELIABILITY PROBLEMS IDENTIFIED IN CHART A IF THE PENNSYLVANIA 502 JUNCTION FACILITIES ALONG WITH THE REMAINDER OF THE 502 JUNCTION SEGMENTS, THE MT. STORM EXPANSION, THE MEADOW BROOK EXPANSION, THE LOUDOUN SEGMENT AND THE LOUDOUN EXPANSION ARE NOT CONSTRUCTED.

A. Electrical occurrences 1 through 9 are violations of NERC Reliability Standard TPL-002-0. This standard requires that the bulk electric system be able to meet customer demands and maintain firm transmission with the loss of a single bulk electric system element. Electrical occurrences 1 through 3 are also violations of the PJM Generator and Load Deliverability Procedure, while electrical occurrence 4 is a violation of the PJM Load Deliverability Procedure and electrical occurrence 9 is a violation of the PJM Generator Deliverability Procedure. Electrical occurrences 5 through 8 are violations of Dominion Virginia Power's planning criteria. Electrical occurrences 10 through 12 are violations of NERC Reliability Standard TPL-003-0, which is the loss of two or more bulk electric system elements. This standard requires the bulk electric system to meet customer demand under these conditions without cascading outages; however, under this standard, controlled load loss or reduction of transfers is permitted.

If the Pennsylvania 502 Junction Facilities, along with the remainder of the 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion are not constructed, PJM as the regional planning authority, Allegheny Power and Dominion Virginia Power will be in violation of these Reliability Standards.

Q. DID THESE STUDIES IDENTIFY ANY LOAD ZONES AFFECTED BY THESE RELIABILITY PROBLEMS?

A. Yes. The studies indicate that the loads (*i.e.*, consumer demand) in the mid-Atlantic and northern Virginia areas within the PJM region will reach a high enough level by 2011 that electric reliability to these areas will be significantly

jeopardized if these facilities are not constructed. For study purposes, the mid-Atlantic area consists of the area along the Atlantic seaboard from the District of Columbia to Northern New Jersey and includes the metropolitan areas of Washington, Baltimore, Philadelphia and Newark. The northern Virginia area includes the service territories of both Allegheny Power and Dominion Virginia Power. The mid-Atlantic and northern Virginia areas were identified by the U. S. Department of Energy in its *National Electric Transmission Congestion Study* issued in August 2006 as parts of a "Critical Congestion Area" and in need of immediate attention through the construction of new transmission facilities. The Pennsylvania 502 Junction Facilities, along with the remainder of the 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion, have been identified by PJM as the most viable solution to this problem.

Q. DO YOU HAVE ANY EXHIBITS THAT DEMONSTRATE THIS LOAD GROWTH?

A. Yes. TrAILCo Exhibit SWG-2 shows the 2006 through 2015 projected summer peak loads for the mid-Atlantic and northern Virginia areas based on the 2006 PJM load forecast. The mid-Atlantic area 2011peak summer load is 63,777 megawatts ("MW"). The northern Virginia area 2011 peak summer load for the Dominion Virginia Power zone is 6,532 MW and the northern Virginia area 2011 peak summer load for the Allegheny Power Zone is 693 MW. These load forecasts formed the basis of the load models that were applied to the RTEP 2011 power system studies that identified the need for the West Virginia Segments, the

502 Junction Substation, the remaining 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion.

Q. PLEASE IDENTIFY THE MAJOR UTILITIES IN THE MID-ATLANTIC AND NORTHERN VIRGINIA AREAS THAT PROVIDE ELECTRIC SERVICE TO CUSTOMERS IN THOSE AREAS.

A. The major utility service areas constituting the mid-Atlantic area for the purposes of my direct testimony are Rockland Electric Company; Public Service Electric & Gas Company; Jersey Central Power & Light Company; Atlantic City Electric Company; Delmarva Power & Light Company; PECO Energy Company; PPL Energy Plus, LLC; Metropolitan Edison Company; Pennsylvania Electric Company; Baltimore Gas and Electric Company; Potomac Electric Power Company and UGI Utilities. The major utilities in the northern Virginia area are Dominion Virginia Power and Allegheny Power. The Dominion Virginia Power service territory in northern Virginia consists of Arlington, Fairfax, Fauquier, Loudoun, Prince William, Spotsylvania and Stafford Counties and the cities of Alexandria, Falls Church, Vienna, Fairfax, Leesburg, Manassas and Warrenton. The Allegheny Power service territory in northern Virginia includes Clarke, Fauquier, Frederick, Greene, Madison, Page, Rappahannock, Shenandoah and Warren Counties.

Q. WHAT IS THE PRIMARY FACTOR CAUSING THE ELECTRICAL NEED FOR THE PENNSYLVANIA 502 JUNCTION FACILITIES, THE REMAINDER OF THE 502 JUNCTION SEGMENTS, THE MT. STORM

EXPANSION, THE MEADOW BROOK EXPANSION, THE LOUDOUN SEGMENT AND THE LOUDOUN EXPANSION?

A. Consumer demand in the mid-Atlantic and northern Virginia areas is the main factor causing the electrical need for these facilities. There are primarily two components to consumer demand, the increase in the number of consumers using electricity and the increase in the amount of electricity each consumer uses. Naturally as the population increases, the demand for electricity increases as well. Also, consumers are adding more equipment that uses electricity, thereby increasing the amount that each consumer uses.

Q. HOW HAS CONSUMER DEMAND IN THE MID-ATLANTIC AND NORTHERN VIRGINIA AREAS INCREASED DURING THE PAST TEN YEARS?

A. TrAILCo Exhibit SWG-3 contains the mid-Atlantic area and northern Virginia area historical summer peak loads for 1995 through 2005. During this period, the mid-Atlantic area load grew by over 20% while the northern Virginia area load grew by over 40% in the Dominion Virginia Power service territory and over 60% in Allegheny Power service territory.

Q. WHAT ARE PJM'S PROJECTIONS FOR CONSUMER DEMAND IN THE MID-ATLANTIC AND NORTHERN VIRGINIA AREAS FOR THE FIVE-YEAR PERIOD OF 2007 THROUGH 2011?

A. TrAILCo Exhibit SWG-2 shows the mid-Atlantic area and northern Virginia area projected summer peak loads for 2006 through 2015. The annual projections for consumer demand in the mid-Atlantic area for 2007 to 2011 are 59,611 MW;

60,965 MW; 61,966 MW; 62,850 MW; and 63,777 MW, respectively, for each of these five years. These projections are based on the 2006 PJM Load Forecast Report that was used as the basis for the load flow models that identified the need for the Pennsylvania 502 Junction Facilities, the remainder of the 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion. The annual projections for consumer demand in Dominion Virginia Power portion of the northern Virginia area for 2007 through 2011 are 6,037 MW; 6,205 MW; 6,316 MW; 6,411 MW; and 6,532 MW, respectively, for each of the five years. The annual projections for consumer demand in the Allegheny Power portion of the northern Virginia area for 2007 through 2011 are 721 MW, 646 MW, 661 MW, 678 MW and 693 MW, respectively, for each of the five years.

Q. HOW WILL ELECTRIC SERVICE CUSTOMERS WITHIN THE ALLEGHENY POWER ZONE BE AFFECTED IF THE PENNSYLVANIA 502 JUNCTION FACILITIES, THE REMAINDER OF THE 502 JUNCTION SEGMENTS, THE MT. STORM EXPANSION, THE MEADOW BROOK EXPANSION, THE LOUDOUN SEGMENT AND THE LOUDOUN EXPANSION ARE NOT CONSTRUCTED?

A. The customers served by Allegheny Power in northern Virginia will be at risk for Electrical Occurrences 1 through 8 and 10 through 12 listed in Chart A. The load in the Allegheny Power Zone that is located to the east of the overloaded transmission lines could be affected in one of two ways if these facilities are not constructed by 2011. First, for any of Electrical Occurrences 1 through 8 listed in

Chart A, load may need to be disconnected in order to reduce the loading on the Mt. Storm-Doubs 500 kV line, a major transmission line that originates at the Mt. Storm Substation in Grant County, West Virginia and continues to the Doubs Substation in Frederick County, Maryland. It is likely that a portion of any disconnected load would be located in the Allegheny Power Zone east of the overloaded facility since this load has a direct impact on the overloaded facility. The Allegheny Power Zone also could be impacted due to the low voltages or voltage collapse resulting from Electrical Occurrences 10 through 12 listed in Chart A.

Q. EARLIER IN YOUR TESTIMONY YOU STATED THAT THE PENNSYLVANIA 502 JUNCTION FACILITIES, THE REMAINDER OF THE 502 JUNCTION SEGMENTS, THE MT. STORM EXPANSION, THE MEADOW BROOK EXPANSION, THE LOUDOUN SEGMENT AND THE LOUDOUN EXPANSION HAVE BEEN IDENTIFIED AS THE MOST VIABLE SOLUTION TO RESOLVE THE POTENTIAL RELIABILITY PROBLEMS YOU HAVE IDENTIFIED IN CHART A. PLEASE EXPLAIN WHY THESE SEGMENTS ARE THE MOST VIABLE SOLUTION TO RESOLVE THESE PROBLEMS.

A. PJM recommended the construction of these facilities collectively as the most viable solution based on its review of all the alternatives considered. This solution solves multiple reliability violations in a cost-effective manner and is completed with the construction of one line at an estimated cost of $850 million.

Q. WHAT SPECIFIC ELECTRICAL ALTERNATIVES DID PJM STUDY AND/OR CONSIDER TO THE CONSTRUCTION OF THESE FACILITIES?

A. A second Mt. Storm-Doubs 500 kV line was considered as an alternative. This alternative did not resolve the overload on the Pruntytown-Mt. Storm 500 kV line (another critical major transmission line originating in Taylor County, West Virginia and extending to the Mt. Storm Substation) and caused the overload to advance from 2014 to 2011. A new Mt. Storm-Loudoun 500 kV line was considered as another alternative. This alternative also did not resolve the overload on the Pruntytown-Mt. Storm 500 kV line and caused the overload to advance from 2014 to 2011. Allegheny Power's original TrAIL proposal, as described by Mr. Hozempa, was considered as an alternative as well. This alternative relieved the overloads; however, the transfer capability increase was less by 750 MW and the cost was more by $450 million than the Pennsylvania 502 Junction Facilities, the remainder of the 502 Junction Segments, the Mt. Storm Expansion, the Meadow Brook Expansion, the Loudoun Segment and the Loudoun Expansion.

Q. WERE ANY ELECTRICAL ALTERNATIVES THAT INVOLVED UPGRADING OR EXPANDING EXISTING TRANSMISSION FACILITIES CONSIDERED?

A. Yes. Consideration was given to reconductoring the Mt. Storm-Doubs 500 kV line, but this was not a practical alternative since the line could not be removed from service for the estimated two-year period required to complete the work.

Also, there would be a significant risk to the reliability of the mid-Atlantic and northern Virginia areas while this line was being rebuilt.

Q. WHY DID PJM SELECT THE PENNSYLVANIA 502 JUNCTION FACILITIES, THE REMAINDER OF THE 502 JUNCTION SEGMENTS, THE MT. STORM EXPANSION, THE MEADOW BROOK EXPANSION, THE LOUDOUN SEGMENT AND THE LOUDOUN EXPANSION FOR CONSTRUCTION OVER THESE ALTERNATIVES?

A. PJM selected these facilities for construction because all of the overloads in the southern portion of the Allegheny Power Zone identified in Chart A were resolved with this alternative. In addition, these facilities together provide the greatest transfer capability increase of the studied alternatives, placement of these facilities in-service by June 2011 is feasible and they constitute the most cost-effective solution.

Q. IF, FOR REASONS BEYOND THE CONTROL OF TRAILCO, THE MEADOW BROOK SEGMENT AND THE LOUDOUN SEGMENT CANNOT BE CONSTRUCTED IN VIRGINIA, WILL RELIABILTY BENEFITS BE PROVIDED IF THE LINE TERMINATES AT MEADOW BROOK SUBSTATION?

A. Yes. The Pruntytown-Mt. Storm overload will be resolved as well as the voltage violations around the Meadow Brook Substation. However, the Mt. Storm-Doubs overload will still exist.

Q. IF, FOR REASONS BEYOND THE CONTROL OF TRAILCO, THE WEST VIRGINIA SEGMENTS CANNOT BE CONSTRUCTED EAST OF THE MT.

STORM SUBSTATION IN WEST VIRGINIA, WILL RELIABILITY BENEFITS BE PROVIDED IF THE WEST VIRGINIA SEGMENTS TERMINATE AT THE MT. STORM SUBSTATION?

A. Yes. The Pruntytown-Mt. Storm overload will be resolved. However, the voltage violations around the Meadow Brook Substation will not be resolved and the overload of the Mt. Storm-Doubs line will not be resolved. Another line will still have to be built to resolve these violations.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does. However, I reserve the right to file such additional testimony as may be necessary or appropriate.

TrAILCo Rebuttal Statement No. 4-R
Witness: Scott W. Gass

Pgs 5K
3/25/08

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION A-110172

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY FOR (I) A CERTIFICATE OF PUBLIC CONVENIENCE TO OFFER, RENDER, FURNISH AND/OR SUPPLY TRANSMISSION SERVICE IN THE COMMONWEALTH OF PENNSYLVANIA; (II) AUTHORIZATION AND CERTIFICATION TO LOCATE, CONSTRUCT, OPERATE AND MAINTAIN CERTAIN HIGH VOLTAGE ELECTRIC TRANSMISSION LINES AND RELATED ELECTRIC SUBSTATION FACILITIES; (III) AUTHORITY TO EXERCISE THE POWER OF EMINENT DOMAIN FOR THE CONSTRUCTION AND INSTALLATION OF AERIAL ELECTRIC TRANSMISSION FACILITIES ALONG THE PROPOSED TRANSMISSION LINE ROUTES IN PENNSYLVANIA; (IV) APPROVAL OF AN EXEMPTION FROM MUNICIPAL ZONING REGULATION WITH RESPECT TO THE CONSTRUCTION OF BUILDINGS; AND (V) APPROVAL OF CERTAIN RELATED AFFILIATED INTEREST ARRANGEMENTS	:	Docket Nos. A-110172 A-110172F0002 A-110172F0003 A-110172F0004 G-00071229

REBUTTAL TESTIMONY OF SCOTT W. GASS

Re: PJM and Regional Planning Process

December 10, 2007

REBUTTAL TESTIMONY OF SCOTT W. GASS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott W. Gass and my business address is 15 Shannon Way, Royersford, Pennsylvania.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I have filed written Direct Testimony on behalf of Trans-Allegheny Interstate Line Company ("TrAILCo"), which has been designated as TrAILCo Statement No. 4.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. This Rebuttal Testimony addresses various assertions, concerning PJM and the regional transmission planning process, by Office of Trial Staff ("OTS") witness Gary Yocca in OTS Statement No. 1, Office of Consumer Advocate ("OCA") witness Peter Lanzalotta in OCA Statement No.1, Energy Conservation Council ("ECC") witness George Loehr in ECC Statement No. 1, and by certain members of the public during public input hearings.

Q. WILL THE USE OF VARIOUS TERMS IN YOUR REBUTTAL TESTIMONY BE CONSISTENT WITH THE DEFINITIONS ASSIGNED TO THOSE TERMS IN THE TABLE OF NOMENCLATURE ATTACHED TO TRAILCO WITNESS FLITMAN'S DIRECT TESTIMONY AS TRAILCO EXHIBIT DEF-1?

A. Yes. In addition, I may define other terms in my rebuttal testimony.

Q. HAVE YOU REVIEWED THE REBUTTAL TESTIMONY FILED BY STEVEN HERLING ON BEHALF OF TRAILCO RELATED TO THE PJM AND NERC STANDARDS AND TESTS UNDERLYING THE NEED FOR TRAIL?

A. Yes.

Q. DO YOU HAVE ANY ADDITIONAL POINTS TO ADD FROM YOUR PERSPECTIVE?

A. Yes. I agree with what Mr. Herling has described as being the PJM and NERC standards and tests. These standards and tests were employed in the identification of the need for TrAIL. It is an important part of both the NERC and PJM processes that any proposed changes to the standards are fully discussed and voted on prior to implementing the changes. It is through this collaborative approach that all participants' viewpoints can be fully vetted and that no one individual's opinion dictates future changes.

Q. HAVE YOU REVIEWED ECC WITNESS LOEHR'S TESTIMONY CONCERNING THE UNDERYLING NEED FOR TRAIL?

A. Yes. Mr. Loehr's testimony concerning the 502 Junction – Mt. Storm – Meadowbrook - Loudoun 500 kV states that no reliability issues were proven and that the underlying motive was economics. I personally supervised the analysis

that was performed to determine the need for TrAIL and I can unequivocally state that there was no underlying motive of economics. Furthermore, the NERC and PJM reliability standards, as approved at that time, were studied and reliability problems were identified as noted in Exhibit SWG-1. Mr. Loehr's testimony does not dispute the fact that there are reliability problems if the existing PJM and NERC reliability standards are evaluated. Instead, he simply unilaterally decides that the standards are too conservative. Mr. Loehr's words are that "TrAILCO and PJM seem to want to build a transmission system capable of delivering every MW from any generator anywhere on the system to any load point in PJM". This shows a complete misunderstanding of the PJM deliverability procedures and is exactly the reason why changes to existing procedures are discussed in an open forum and include the input of other participants and stakeholders.

Q. DID THE PJM STUDY OF NERC CATEGORY C3 CONTINGENCIES ALLOW FOR MANUAL SYSTEM ADJUSTMENT?

A. Yes. PJM did study manual system adjustments, as allowed by NERC Criteria, after the first Category B contingency and prior to the second Category B contingency. However, the contingencies identified in Exhibit LAH-3 can not be resolved through re-dispatch of generation or through curtailment of firm transfers. As stated in Mr. Hozempa's rebuttal testimony, the amount of load that would need to be shed after the first contingency in anticipation of the second contingency has reached a sufficient level such that manual load shedding is no longer considered an acceptable solution to resolve the reliability problems.

I'd also like to provide one clarification around the terminology used to describe NERC Category C3 contingencies. The term "n-2" is sometimes used to describe NERC Category C3 contingencies. The term "n-2" could be misinterpreted to indicate two simultaneous contingencies without any ability for manual system adjustments. A more precise term to describe the NERC Category C3 contingencies would be "n-1-1" which better describes the analysis which was conducted.

Q. DID PJM CALCULATE THE PROBABILITY THAT THE CONTINGENCIES LISTED IN TRAILCO EXHIBIT LAH-3 WOULD ACTUALLY OCCUR?

A. No. NERC Category C3 is a set of deterministic criteria and, as such, requires the evaluation of all combinations of one NERC Category B contingency followed by (after manual system adjustment) a second NERC Category B contingency. The calculation of a probability associated with any specific n-1-1 outage is not applicable for NERC Category C3 contingencies.

Q. DO YOU CONSIDER PJM'S GENERATOR AND LOAD DELIVERABILITY TESTS TO BE TOO CONSERVATIVE?

A. No. The PJM Generator and Load Deliverability tests are the procedures by which PJM studies NERC Category B contingencies. Section R1.3.2 of NERC Standard TPL-002-0 states that the analysis should "Cover critical system conditions and study years as deemed appropriate by the responsible entity." The PJM Generator and Load Deliverability tests have been applied consistently for

RTEP baseline studies, generation interconnection studies and merchant transmission interconnection studies on the PJM system for over 7 years. Any PJM member whether they are generation owners, transmission owners, or end use customers has the ability to request modifications to the existing procedures if they deem the procedures too conservative. Any requested changes to the criteria are then fully discussed and ultimately approved or not-approved through the PJM committee structure. As such, the PJM Generator and Load Deliverability tests are the method accepted by the PJM membership through which NERC Category B contingencies are studied.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes. However, I reserve the right to file such additional testimony as may be necessary or appropriate, and to supplement my rebuttal after reviewing responses to discovery propounded to other parties.

TrAILCo Rejoinder Statement No. 4-RJ
Witness: Scott W. Gass

Pgl JK
3/25/08
A-110172

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY FOR (I) A CERTIFICATE OF PUBLIC CONVENIENCE TO OFFER, RENDER, FURNISH AND/OR SUPPLY TRANSMISSION SERVICE IN THE *COMMONWEALTH OF PENNSYLVANIA*; (II) AUTHORIZATION AND CERTIFICATION TO LOCATE, CONSTRUCT, OPERATE AND MAINTAIN CERTAIN HIGH VOLTAGE ELECTRIC TRANSMISSION LINES AND RELATED ELECTRIC SUBSTATION FACILITIES; (III) AUTHORITY TO EXERCISE THE POWER OF EMINENT DOMAIN FOR THE CONSTRUCTION AND INSTALLATION OF AERIAL ELECTRIC TRANSMISSION FACILITIES ALONG THE PROPOSED TRANSMISSION LINE ROUTES IN PENNSYLVANIA; (IV) APPROVAL OF AN EXEMPTION FROM MUNICIPAL ZONING REGULATION WITH RESPECT TO THE CONSTRUCTION OF BUILDINGS; AND (V) APPROVAL OF CERTAIN RELATED AFFILIATED INTEREST ARRANGEMENTS	:	Docket Nos. A-110172 A-110172F0002 A-110172F0003 A-110172F0004 G-000721229

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REJOINDER TESTIMONY OF SCOTT W. GASS

Re: Regional Planning Process

March 19, 2008

REJOINDER TESTIMONY OF SCOTT W. GASS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Scott W. Gass and my business address is 15 Shannon Way, Royersford, Pennsylvania.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?

A. Yes. I have filed written Direct Testimony on behalf of Trans-Allegheny Interstate Line Company ("TrAILCo"), which has been designated as TrAILCo Statement No. 4. I also filed written Rebuttal Testimony on behalf of TrAILCo, which has been designated as TrAILCo Statement No. 4-R.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR REJOINDER TESTIMONY.

A. This Rejoinder Testimony addresses various assertions contained in surrebuttal testimony from opponents, concerning regional planning. Specifically, my rejoinder addresses surrebuttal filed by Energy Conservation Council ("ECC") witnesses George Loehr in ECC Statement SR-1 and Robert Q. Hanham in ECC Statement SR-2.

Q. WILL THE USE OF VARIOUS TERMS IN YOUR REJOINDER TESTIMONY BE CONSISTENT WITH THE DEFINITIONS ASSIGNED TO THOSE TERMS IN THE TABLE OF NOMENCLATURE ATTACHED TO TRAILCO WITNESS FLITMAN'S DIRECT TESTIMONY AS TRAILCO EXHIBIT DEF-1?

A. Yes. In addition, I may define other specific terms in my rejoinder.

Q. DO YOU AGREE WITH ECC WITNESS HANHAM'S SURREBUTTAL (PAGE 2 LINES 1 THROUGH 5) THAT "CONSUMER DEMAND" IN THE MID-ATLANTIC ("AREAS ALONG THE ATLANTIC SEABOARD FROM THE DISTRICT OF COLUMBIA TO NORTHERN NEW JERSEY") AND NORTHERN VIRGINIA IS THE PRIMARY FACTOR CAUSING "ELECTRICAL NEED FOR THE TRAIL PROJECT"?

A. No, I do not agree. The mid-Atlantic and northern Virginia "consumer demand" is not a primary factor causing the need for the Prexy Facilities which include the 500 kV line between the 502 Junction and Prexy substations. The electrical need for the Pennsylvania 502 Junction Facilities and the remainder of the 502 Junction – Loudoun 500 kV line is driven by load in the mid-Atlantic Region and northern Virginia. The need for the Prexy Facilities and the need for the Pennsylvania 502 Junction Segment are separate and distinct.

Q. DO YOU AGREE WITH ECC WITNESS HANHAM'S SURREBUTTAL (PAGE 3 LINES 7 THROUGH 9) THAT STATES "GASS, HIMSELF, CONFIRMS THAT "LOAD POCKETS" IN THE NORTHERN VIRGINIA AREA (NOT PENNSYLVANIA) DRIVE THE PROJECT."?

A. No, I do not agree. Once again, a distinction has to be made between the "Project," the "Prexy Facilities," and the "Pennsylvania 502 Junction Facilities," the last of which continue through West Virginia and end at Loudoun substation in Virginia. The section of my direct testimony on "load pockets" referenced by Mr. Hanham is specifically related to the need for the Pennsylvania 502 Junction Facilities, not the Prexy Facilities.

Q. ECC WITNESS LOEHR'S SURREBUTTAL (PAGE 22 LINES 17 THROUGH 26) STATES THAT OVERLOADS 1 THROUGH 9 IN EXHIBIT SWG-1 COULD BE ELIMINATED BY USE OF "TRANSMISSION CONSTRAINED DISPATCH." DO YOU AGREE WITH MR. LOEHR'S CONCLUSION?

A. No, I disagree with Mr. Loehr's conclusion. As identified in my direct testimony, overloads 1 through 9 are violations of *NERC Standard* TPL-002, a copy of which is attached as TrAILCo Exhibit SWG-RJ-1. NERC Standard TPL-002 states that in order to be valid, the assessment shall cover critical system conditions and study years as deemed appropriate by the responsible entity (section R1.3.2). TrAILCo Exhibit-SWG-RJ-2 contains a NERC interpretation of section R1.3.2 of TPL-002 where NERC states that "[t]he selection of the credible critical generation dispatch for modeling of critical system conditions is within the

discretion of the Planning Authority/Transmission Planner." PJM is the Planning Authority and as such applies the PJM Generator and Load Deliverability procedures which provided the critical system conditions that resulted in overloads 1 through 4 and 9 in Exhibit SWG-1. Dominion is the Transmission Planner and as such has developed its own critical system condition, the application of which resulted in overloads 5 through 8. Mr. Loehr's suggestion of applying a "transmission constrained dispatch" to eliminate the overloads is an incorrect application of the Planning Authority and Transmission Planner criteria that have been applied consistently in both the PJM system and the Dominion system for many years.

Let me reiterate that PJM's 2006 RTEP showed an overload on the Mt. Storm-Doubs 500 kV circuit under ***three*** separate planning tests: PJM's load deliverability and generator deliverability tests and Dominion Virginia Power's planning criteria. Additionally, Mt. Storm-Doubs 500 kV was identified as being overloaded for four different contingencies. These results overwhelmingly indicate a reliability problem in 2011 for a number of system conditions and various contingencies. While all these results indicate a reliability problem, the test resulting in the highest % loading on Mt. Storm-Doubs 500 kV was the PJM load deliverability procedure for an outage of either Mt. Storm-Greenland Gap 500 kV (electrical occurrence #1) or Greenland Gap-Meadowbrook 500 kV (electrical occurrence #2). In either contingency, the Mt. Storm-Doubs 500 kV line is loaded to ***106%*** of the emergency rating, or 156 MVA above the 2598

MVA conductor rating, a very significant violation. It is my view that PJM and TrAILCo have effectively demonstrated that serious reliability issues exist affecting major transmission lines, and the Commission should act affirmatively to address them.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes. However, I reserve the right to provide such additional testimony as may be necessary or appropriate.

TrAILCo Exhibit SWG-1

Pgh 5K
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Chart A

Electric Reliability Problems
(Facility ownership shown in Chart B)

	Electrical Occurrence	Electrical Result
1	Outage of Mount Storm – Greenland Gap Line #572A.	
2	Outage of Meadowbrook – Greenland Gap Line #572B.	
3	Outage of Hatfield – Black Oak 500 kV Line # 542.	
4	Outage of Bedington – Black Oak 500 kV Line # 544.	
5	Outage of Mount Storm – Greenland Gap 500 kV Line # 572A while Possum Point Unit #5 is unavailable.	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads.
6	Outage of Meadowbrook – Greenland Gap Line #572B while Possum Point Unit #5 is unavailable.	
7	Outage of Hatfield – Black Oak 500 kV Line # 542 while Possum Point Unit #5 is unavailable.	
8	Outage of Bedington – Black Oak 500 kV Line # 544 while Possum Point Unit #5 is unavailable.	
9	Outage of Hatfield – Black Oak 500 kV Line # 542.	Mount Storm – Pruntytown 500 kV Line #510 exceeds its emergency rating and overloads.
10	Outage of Morrisville – Meadow Brook 500 kV Line #580 and the Meadow Brook – Greenland Gap Line #572B.	The 138 kV system voltage level around Meadow Brook Substation drops below acceptable limits and could lead to a voltage collapse in the area.

	Electrical Occurrence	Electrical Result
11	Outage of the Hatfield – Black Oak 500 kV Line #542 and Mount Storm – Doubs Line #512.	The 500 kV and 138 kV system voltage levels around Meadow Brook Substation drops below acceptable limits.
12	Outage of the Black Oak – Bedington 500 kV Line #544 and Mount Storm – Doubs Line #512.	

Chart B

Facility Ownership

Facility	Owner
Line #510	Allegheny Power
Line #512	Dominion
Lines #572A and #572B	Jointly owned by Allegheny Power and Dominion
Line #542	Allegheny Power
Line #544	Allegheny Power
Line #580	Jointly owned by Allegheny Power and Dominion
Meadow Brook Substation	Allegheny Power
138 kV system around Meadow Brook Substation	Allegheny Power
500 kV system around Meadow Brook Substation	Allegheny Power and Dominion

TrAILCo Exhibit SWG-2
Pgh. 5K
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Projected Summer Peak Loads (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Cumulative
Mid-Atlantic Region	58742	59611	60965	61966	62850	63777	64648	65798	66845	67725	
% Growth		1.5%	2.3%	1.6%	1.4%	1.5%	1.4%	1.8%	1.6%	1.3%	15.3%
Northern Virginia - Dominion	5936	6037	6205	6316	6411	6532	6656	6780	6911	7035	
% Growth		1.7%	2.8%	1.8%	1.5%	1.9%	1.9%	1.9%	1.9%	1.8%	18.5%
Northern Virginia - APS	611	630	646	661	678	693	710	728	748	768	
% Growth		3.1%	2.5%	2.3%	2.6%	2.2%	2.5%	2.5%	2.7%	2.7%	25.7%

TrAILCo Exhibit SWG-3

Pgh JK
3/25/08
A-110172

Historical Summer Peak Loads (MW)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	Cumulative
Mid-Atlantic Region	48524	44302	49406	48397	51700	49430	54072	55569	53566	52049	59042	
% Growth		-8.7%	11.5%	-2.0%	6.8%	-4.4%	9.4%	2.8%	-3.6%	-2.8%	13.4%	21.7%
Northern Virginia - Dominion	4321	3939	4562	4618	5022	4688	5244	5399	5323	5143	6067	
% Growth		-8.8%	15.8%	1.2%	8.7%	-6.7%	11.9%	3.0%	-1.4%	-3.4%	18.0%	40.4%
Northern Virginia - APS	406	386	429	453	469	493	554	566	564	580	654	
% Growth		-4.9%	11.1%	5.6%	3.5%	5.1%	12.4%	2.2%	-0.4%	2.8%	12.8%	61.1%

Standard TPL-002-0 — System Performance Following Loss of a Single BES Element

A. Introduction

1. **Title:** System Performance Following Loss of a Single Bulk Electric System Element (Category B)

2. **Number:** TPL-002-0

3. **Purpose:** System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** April 1, 2005

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made annually.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B.

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard TPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard TPL-002-0_R1 and TPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard TPL-002-0_R3.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Compliance Monitor: Regional Reliability Organizations.
   Each Compliance Monitor shall report compliance and violations to NERC via the NERC Compliance Reporting Process.

   1.2. Compliance Monitoring Period and Reset Timeframe

   Annually.

   1.3. Data Retention

   None specified.

   1.4. Additional Compliance Information

   None.

2. **Levels of Non-Compliance**

   2.1. Level 1: Not applicable.

   2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

   2.3. Level 3: Not applicable.

   2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New

Table I. Transmission System Standards — Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating[a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No[b] No[b] No[b] No[b]	No No No No
	Single Pole Block, Normal Clearing[c]: 4. Single Pole (dc) Line	Yes	No[b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing[c]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG or 3Ø Fault, with Normal Clearing[c], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing[c]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled[c]	No
	Bipolar Block, with Normal Clearing[c]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing[c]: 5. *Any two circuits of a multiple circuit towerline*[f]	Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c]	No No
	SLG Fault, with Delayed Clearing[c] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c] Planned/ Controlled[c]	No No No No

Standard TPL-002-0 System Performance Following Loss of a Single BES Element

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing[c] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing[e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission *planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed* contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

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Interpretation of TPL-002-0 Requirements R1.3.2 and Requirement R1.3.12 and the identical requirements (Requirements R1.3.2 and Requirement R1.3.12) in TPL-003-0 for MISO

Request for Interpretation received from MISO on August 9:

MISO asks if the TPL standards require that any specific dispatch be applied, other than one that is representative of supply of firm demand and transmission service commitments, in the modeling of system contingencies specified in Table 1 in the TPL standards.

MISO then asks if a variety of possible dispatch patterns should be included in planning analyses including a probabilistically based dispatch that is representative of generation deficiency scenarios, would it be an appropriate application of the TPL standard to apply the transmission contingency conditions in Category B of Table 1 to these possible dispatch pattern.

R1.3.2	Cover critical system conditions and study years as deemed appropriate by the responsible entity.

The following interpretation of TPL-002-0 and TPL-003-0 R1.3.2 was developed by the NERC Planning Committee on September 12, 2007:

TPL-002 and TPL-003 do not specify the process for selection of the credible critical generation dispatch for modeling of critical system conditions. The selection of the credible critical generation dispatch for modeling of critical system conditions is within the discretion of the Planning Authority/Transmission Planner.

Request for Interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 received from MISO on August 9:

MISO asks if the term "planned outages" means only already known/scheduled planned outages that may continue into the planning horizon, or does it include potential planned outages not yet scheduled that may occur at those demand levels for which planned (including maintenance) outages are performed?

If the requirement does include not yet scheduled but potential planned outages that could occur in the planning horizon, is the following a proper interpretation of this provision?

> *The system is adequately planned and in accordance with the standard if, in order for a system operator to potentially schedule such a planned outage on the future planned system, planning studies show that a system adjustment (load shed, re-dispatch of generating units in the interconnection, or system reconfiguration) would be required concurrent with taking such a planned outage in order to prepare for a Category B contingency (single element forced out of service)? In other words, should the system in effect be planned to be operated as for a Category C3 n-2 event, even though the first event is a planned base condition?*

If the requirement is intended to mean only known and scheduled planned outages that will occur or may continue into the planning horizon, is this interpretation consistent with the original interpretation by

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NERC of the standard as provided by NERC in response to industry questions in the Phase I development of this standard1?

R1.3.12	Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

The interpretation of TPL-002-0 and TPL-003-0 Requirement R1.3.12 was developed by the NERC Planning Committee on September 12, 2007

TPL-002-0 and TPL-003-0 explicitly provide that the inclusion of planned (including maintenance) outages of any bulk electric equipment at demand levels for which the planned outages are performed are within the discretion of the Planning Authority/Transmission Planner.

OCA Cross Exhibit 3

ATTACHMENT ECC-I-34-A
AP Required PJM Projects 2006-2011 R1
Tab: TOI Identified

TOI Identified Projects for Allegheny Power
2005 - 2011

State	Month	Year	Transmission Project	2005	2006	2007	2008	2009	2010	2011	TOTAL
TOTAL BY YEAR & OVER 7-YEAR PERIOD				$ 2.3	$ 5.5	$31.2	$39.1	$ 31.0	$ 44.0	$ -	$ 153.1
PA	6	2010	Prexy SS - 502 Junction 500kV Substation and 500kV Line		$ -	$16.0	$29.0	$ 31.0	44.0	$ -	$120.0
MD	5	2007	Doubs SS Install DL-57 and DL-58 500kV Breakers and Remove DL-56 500kV Breaker		$ 0.2	$ 1.6	$ -	$ -	$ -	$ -	$1.8
PA	11	2007	Cabot SS Install 138kV Capacitor		$ -	$ 0.8	$ -	$ -	$ -	$ -	$0.8
WV	12	2008	Glen Falls - Trissler Reconductor 138kV Line		$ 1.8	$ 3.2	$ 1.2	$ -	$ -	$ -	$6.2
WV/MD	12	2005	Black Oak and Bedington SS Upgrade RTUs and Line Traps	$ 0.1	$ -	$ -	$ -	$ -	$ -	$ -	$0.1
MD	11	2008	Doubs SS Replace Control Building		$ 0.9	$ 2.5	$ 2.0	$ -	$ -	$ -	$5.4
MD	5	2007	Doubs SS Upgrade RTUs for 512 & 514 Line terminals		$ -	$ -	$ 0.1	$ -	$ -	$ -	$0.1
MD	6	2008	Doubs - Monacacy Convert 138kV facilities to 230kV Operation		$ -	$ 3.8	$ 5.6	$ -	$ -	$ -	$9.4
WV	11	2006	Hardy SS Increase 138kV Capacitor Bank		$ -	$ 0.2	$ -	$ -	$ -	$ -	$0.2
PA	12	2008	Stoner Junction - King Farm Reconductor 138kV Line		$ -	$ -	$ 0.9	$ -	$ -	$ -	$0.9
WV	6	2008	Windsor - Rebuild SS		$ 0.1	$ 3.1	$ -	$ -	$ -	$ -	$3.2
WV	3	2006	Weston SS Install 138kV Capacitor Bank		$ 0.4	$ -	$ -	$ -	$ -	$ -	$0.4
WV	11	2006	Pruntytown SS - Replace Trap, and Upgrade RTUs		$ 0.1	$ -	$ -	$ -	$ -	$ -	$0.1
MD	12	2006	Lime Kiln Convert 138kV facilities to 230kV Operation	$ 2.2	$ 2.0	$ -	$ -	$ -	$ -	$ -	$4.2
MD	5	2008	Doubs SS - Replace a line trap, Upgrade RTUs and Relay Circuitry		$ -	$ -	$ 0.1	$ -	$ -	$ -	$0.1
VA	5	2008	Meadow Brook SS - Upgrade RTUs		$ -	$ -	$ 0.0	$ -	$ -	$ -	$0.0
WV	5	2008	Wylie Ridge SS - Replace Line Trap, Upgrade RTUs and Relay Circuitry		$ -	$ -	$ 0.1	$ -	$ -	$ -	$0.1
WV	5	2008	Belmont SS - Replace Line Trap, Upgrade RTU and Relay Circuitry		$ -	$ -	$ 0.0	$ -	$ -	$ -	$0.0
WV	5	2008	Harrison SS - Replace two line traps, Upgrade RTUs and Relay Circuitry		$ -	$ -	$ 0.1	$ -	$ -	$ -	$0.1
PA	5	2008	Cabot SS - Upgrade RTUs and Relay Circuitry		$ -	$ -	$ 0.0	$ -	$ -	$ -	$0.0
PA	5	2008	Yukon SS - Upgrade RTU		$ -	$ -	$ 0.0	$ -	$ -	$ -	$0.0
					$ -	$ -	$ -	$ -	$ -	$ -	$0.0
			TOTAL by YEAR	$ 4.0	$ 9.5	$28.5	$22.5	$ 5.0	$ 44.0	$ -	$ 144.0

ATTACHMENT ECC-I-34-A
AP Required PJM Projects 2006-2011 R1
Tab: PJM Required

PJM Required Projects for Allegheny Power
2005 - 2011

State	Month	Year	Transmission Project	2005	2006	2007	2008	2009	2010	2011	TOTAL
TOTAL BY YEAR & OVER 7-YEAR PERIOD				$ 4.1	$ 10.5	$64.2	$100.5	$203.5	$ 286.6	$ 200.8	$ 870.2
WV	4	2005	Wylie Ridge SPS	$ 0.1	$ -	$ -	$ -	$ -	$ -	$ -	$0.1
MD	9	2005	Ringgold SS Capacitor	$ 0.4	$ -	$ -	$ -	$ -	$ -	$ -	$0.4
MD	5	2006	Carroll SS Capacitor	$ 0.4	$ 0.1	$ -	$ -	$ -	$ -	$ -	$0.5
MD	12	2005	Doubs #1 Transformer	$ 3.2	$ -	$ -	$ -	$ -	$ -	$ -	$3.2
WV	6	2008	Black Oak Dynamic Response Device (SVC)	$ -	$ 4.0	$19.5	$ 11.5	$ -	$ -	$ -	$35.0
WV	12	2007	Wylie Ridge Transformers	$ -	$ 5.0	$ 7.0	$ -	$ -	$ -	$ -	$12.0
WV	6	2006	Wylie Ridge Trf. Coolers		$ 0.5	$ -	$ -	$ -	$ -	$ -	$0.5
VA	12	2008	Meadowbrook Transformer		$ -	$ 2.0	$ 5.0	$ -	$ -	$ -	$7.0
MD	6	2009	Doubs - Dickerson Reconductor Lines		$ -	$ -	$ 4.0	$ 5.2	$ -	$ -	$9.2
WV	5	2009	Bedington Transformer		$ -	$ -	$ 2.0	$ 5.0	$ -	$ -	$7.0
MD	6	2011	Doubs #2, #3, #4 Transformers & Bus upgrades		$ -	$ -	$ 0.7	$ 5.0	$5.0	$5.0	$15.7
WV	12	2008	Yukon 500/138kV Spare Transformer		$ -	$ -	$ 3.8	$ -	$ -	$ -	$3.8
VA	6	2011	Meadow Brook Dynamic Response Device (SVC) 525Mvar		$ -	$ -	$ -	$ 4.0	$ 19.5	$ 11.5	$35.0
MD	6	2011	Doubs Dynamic Response Device (SVC) 300Mvar		$ -	$ -	$ -	$ 3.0	$14.9	$8.8	$26.7
VA	5	2008	North Shenandoah 138/115kV Transformer		$ -	$ -	$ -	$ 2.0	$ -	$ -	$2.0
WV/VA	5	2010	Stonewall - Inwood 138kV Reconductor Line		$ -	$ -	$ -	$ 0.4	$1.2	$ -	$1.6
WV	5	2009	Bedington - Nipetown 138kV Reconductor Line		$ -	$ -		$ 0.4	$ -	$ -	$0.4
VA	5	2009	Double Tollgate - Old Chapel 138kV Reconductor Line		$ -	$ -	$ 0.5	$ 2.0	$ -	$ -	$2.5
PA/WV/MD/VA	6	2011	502 Junction - Mt Storm 500kV - Meadow Brook and 500kV Line to AP territorial line		$ -	$35.0	$ 70.0	$175.0	$245.0	$175.0	$700.0
PA	12	2011	Upgrade EMS System		$ 0.9	$ 0.7	$ 3.0	$ 1.5	1.0	0.5	$7.6
					$ -	$ -	$ -	$ -	$ -	$ -	$0.0
					$ -	$ -	$ -	$ -	$ -	$ -	$0.0
			TOTAL by YEAR	$ 4.0	$ 9.5	$28.5	$ 22.5	$ 5.0	$ -	$ -	$ 74.8

PROPRIETARY INFORMATION

Docket Number A-110172

Name of Document OCA Cross Exhibit Map

Date Document Received 3-25-2008

DOCUMENT CONTAINS

PROPRIETARY INFORMATION

U.S. DEPARTMENT OF ENERGY

Draft National Corridor Designations: Key Findings and Conclusions

April 26, 2007

Designation of a National Corridor:

- Represents a determination by the Department of Energy (DOE) under section 216(a) of the Federal Power Act (FPA) [created by section 1221(a) of the Energy Policy Act of 2005] that consumers are being adversely affected by transmission capacity constraints or congestion, and that resolving the area's electricity problem (or problems) is a matter of sufficient national importance to warrant the exercise of the Secretary's discretion to designate a national interest electric transmission corridor (National Corridor).

- Provides a potential siting venue at the Federal Energy Regulatory Commission (FERC) for transmission facilities within the area bounded by the National Corridor pursuant to FPA section 216(b). (See Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities, Order No. 689, 71 Fed. Reg. 69,440 (Dec. 1, 2006), FERC Stats. & Regs. ¶ 31,234 (2006)(Final Rule).

Principal Generic Findings and Conclusions regarding the Draft National Corridor Designations

- With these draft National Corridor designations, the DOE is encouraging a full consideration of all options available to meet local, regional and national demand – including more local generation, demand response, and energy conservation measures. A designation does not direct anyone to build a transmission facility in a certain area or determine the route for any proposed transmission facility. Nor is it an assertion that additional transmission capacity is the only, or preferred, solution to resolve the congestion. In other words, the Federal government is *not* dictating *how* the States, regions, transmission providers or electric utilities should meet their energy challenges.

- A National Corridor should cover a sufficiently broad geographic area. It should be large enough to help facilitate access to a range of possible generation sources that could serve the congested area, and preserve the options of State authorities and private companies to determine which generation sources are of principal interest. It should also be broad enough to allow consideration of a range of potential

transmission projects and routes by the appropriate transmission planning entities, siting authorities (e.g., State agencies and, under certain conditions, FERC) and prospective transmission developers.

- In determining the boundaries of the two draft National Corridors, DOE did not carve out environmentally sensitive lands because the statute does not exclude such lands from inclusion in a National Corridor. In the event of a FERC siting proceeding, FERC would conduct a review under the National Environmental Protection Act, which would include analysis of alternative routes for that project, including route realignments necessary to avoid adverse effects on the environment, landowners, and local communities. Therefore, DOE has attempted to make the draft National Corridors broad enough to encompass a range of alternative routes for potential transmission projects, thus leaving the determination of the best route for a specific project to the siting authorities, who are better positioned to make such a determination.

  Further, nothing in FPA section 216 alters the applicability of Federal environmental and cultural statutes and regulations. Thus, any permit issued by FERC would be subject to all the requirements of Federal environmental or cultural statutes and regulations. Such requirements approvals would include approvals that are required from the Fish and Wildlife Service, and from State agencies that administer the Clean Water Act, the Clean Air Act and the Coastal Zone Management Act (which are Federal statutes administered by State agencies).

  Finally, any routing of a transmission facility through property owned by the United States or a State would be subject to the consent of the appropriate Federal or State land-managing agency, because the statute does not grant the holder of a FERC permit the right of eminent domain over such land.

- A National Corridor should have specific, readily identifiable boundaries, so that government officials, land-owners, and other parties will be able to determine easily whether specific areas are within the Corridor. Accordingly, DOE proposes to make the boundaries of these draft National Corridors coincident with the boundaries of enclosed counties.

- A National Corridor should remain in place for a substantial period of time, because it takes 5 to10 years or longer to develop proposals for new transmission facilities (or alternatives to them), obtain government approvals, obtain rights-of-way, and put such new infrastructure in place. As a general practice, DOE proposes to make National Corridor designations for an initial period of 12 years, with the possibility of renewal or extension under appropriate conditions (such as while an application remains under consideration by FERC), and has used that period for these draft National Corridors designations.

Available at: http://nietc.anl.gov/documents/docs/FindingsAndConclusions.pdf

Principal Findings and Conclusions Concerning the Draft Mid-Atlantic Area National Corridor Designation

- Since at least 2004, transmission constraints have been limiting electricity flows on key trunk lines in Pennsylvania-New Jersey-Maryland Interconnection (PJM) and the New York Independent System Operator (NYISO), causing persistent congestion that adversely affects consumers in downstream urban load centers, including those in the metropolitan New York City area, New Jersey, eastern Pennsylvania, Delaware, eastern Maryland, the District of Columbia, and northern Virginia.

- Modeling for DOE's 2006 Congestion Study projected that, without corrective action, the congestion in this area, with its adverse effects on consumers, will continue or worsen.

- As a result of transmission constraints, high-production-cost generators in eastern PJM and southeastern New York State are used extensively, while generating capacity at lower-production-cost generators in western PJM and western and northern New York State is available but inaccessible. These additional costs are passed on to electricity consumers.

- In terms of the additional electricity production costs they cause, the constraints in PJM and NYISO are among the worst in the entire Eastern Interconnection. PJM, for example, reported total congestion costs within its footprint of $2.09 billion for 2005.

- Congestion problems, when severe, may threaten reliability. Analyses conducted by PJM project that without the addition of new west-to-east transmission capacity, reliability violations will occur in the Baltimore-Washington-northern Virginia area by 2011, in northern New Jersey by 2014, and in central Pennsylvania by 2019. Similarly, NYISO reports that due to the combination of demand growth, retirement of aging generation capacity, and transmission constraints, resource adequacy violations are expected in southeastern New York State by 2011, unless corrective actions are taken.

- Even without reliability problems, transmission congestion raises consumers' electricity bills. Reliability problems, however, would introduce additional major costs. Estimates of the total cost of the August 14, 2003 blackout in the Midwest and Northeast ranged between $4 and $10 billion for the U.S. alone; substantial additional costs were incurred in Canada. Smaller scale reliability events still involve significant costs and disruptions.

- The Mid-Atlantic Critical Congestion Area is home to 55 million people (19 percent of the Nation's 2005 population) and is responsible for $2.3 trillion of gross state product (18 percent of the 2005 gross national product). Given the large number of military and other facilities in this area that are extremely important to the national defense and homeland security, as well as the vital importance of this populous area to the Nation as an economic center, any deterioration of the electric reliability or

economic health of this area would constitute a serious risk to the well-being of the Nation.

- Given the long lead-times associated with the development of new transmission capacity (or possible alternatives) and the economic and strategic importance to the Nation of this broad area, focused attention to address the area's congestion problems is needed.

Findings and Conclusions Concerning the Draft Southwest Area National Corridor Designation

- Since at least 2004, key transmission paths into and within southern California have been constrained causing persistent congestion that adversely affects consumers in downstream urban load centers.

- The modeling performed for the Congestion Study projected that without corrective action, the congestion in this area, with its adverse affects on consumers will continue.

- Congestion problems, when severe, may threaten reliability. In recent years, the electricity supply capability within Southern California, combined with supplies that can be imported from external sources, has been barely enough to meet peak electricity demand. In the summer of 2005, the California Independent System Operator (CAISO) declared two "Stage 2 Emergencies" in Southern California (July 21 and 22) and a transmission emergency occurred on August 25 that resulted in the curtailment of 900 megawatts (MW) of firm load. In the summer of 2006, rolling blackouts were avoided during a period of extremely hot weather only through a combination of good fortune, extraordinary efforts by the utilities, CAISO, and the Bonneville Power Administration, and timely cooperation by electricity consumers to reduce electricity demand. CAISO expects that electricity supply resources in Southern California will be very tight again in the summer of 2007.

- CAISO notes that load in Southern California has been growing at a rate of approximately 1.5 percent annually, which translates into a total of approximately 657 MW of new load that needs to be served each year. CAISO notes that this rate of load growth, combined with the threat of extreme weather conditions, such as a 1-in-10-year heat wave, could mean that by 2015, the loss of the transmission capacity in a single critical transmission path could necessitate the curtailment of approximately 1,500 MW of load. CAISO states that in the event of a double-line contingency on that path at peak load, anywhere from 500 to 1,000 MW of load would need to be curtailed.

- Particular areas in Southern California are especially vulnerable to reliability problems. CAISO notes that the San Diego area is projected to be deficient in overall generation capacity by the year 2010 due to severe import limits. CAISO also notes

looming reliability problems on the South of Lugo path, a major CAISO internal path that serves the Los Angeles Basin. Similarly, the Los Angeles Department of Water and Power (LADWP) stated in its comments to the Department that: "Zone SP26 is a large load center that is currently experiencing reliability problems because of transmission constraints. . . . Zone SP26 will likely continue its dependence on imports, so transmission improvements are needed to avoid future violations of reliability standards. . . ."

- Even without reliability problems, transmission congestion raises consumers' electricity bills. Reliability problems, however, would introduce additional major costs. For example, on Saturday, August 10, 1996, a blackout affected several western states, including much of California, for several hours. The California Energy Commission (CEC) conducted a survey to gauge the effects and implications of the blackout. The outage affected slightly less than half of California's residential electricity customers, 20 percent of the commercial customers, and 25 percent of the industrial customers. Forty-one percent of the commercial respondents and 31 percent of the industrial respondents said that the outage was "very disruptive" to their operations and reported losses in excess of $40 million.

- The Southern California Critical Congestion Area is home to 20.7 million people (7.0 percent of the Nation's 2005 population) and produces about $950 billion of gross state product (7.7 percent of the 2005 gross national product). Given the large number of military and other facilities in the Southern California Critical Congestion Area that are extremely important to the national defense and homeland security, as well as the vital importance of this populous area to the Nation as an economic center, any deterioration of the electric reliability or economic health of this area would constitute a serious risk to the well-being of the Nation.

- Given the long lead-times associated with the development of new transmission capacity (or possible alternatives) and the economic and strategic importance to the Nation of this broad area, focused attention to address the area's congestion problems is needed.

ECC Cross Exam No 4
MAR 2 5 2008 Pgh VK A-110172

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

Case No. 07-0508-E-CN

TRANS-ALLEGHENY INTERSTATE LINE COMPANY

Application of Trans-Allegheny Interstate Line Company for a certificate of public convenience and necessity under W. Va. Code § 24-2-11a authorizing the construction and operation of the West Virginia segments of a 500 kV electric transmission line and related facilities in Monongalia, Preston, Tucker, Grant, Hardy, and Hampshire Counties, and for related relief

REBUTTAL TESTIMONY OF STEVEN R. HERLING

January 4, 2008

interconnection queue since the development of the RPM construct, these projects are still in the early stages of the interconnection process. The timing and severity of the reliability criteria violations underlying the need for TrAIL do not allow PJM and TrAILCo to delay in the hope that some of these projects will proceed to completion and help to defer or obviate the need for TrAIL.

III. OTHER TRANSMISSION ENHANCEMENTS/MODIFICATIONS AS AN ALTERNATIVE TO TRAIL

Q. PLEASE COMMENT WITH RESPECT TO TESTIMONY THAT RECONDUCTORING OF BOTH MT. STORM-DOUBS AND PRUNTYTOWN-MT. STORM SHOULD HAVE BEEN MORE THOROUGHLY STUDIED BY PJM AS AN ALTERNATIVE TO TRAIL.

A. PJM considered the option to reconductor the Mt. Storm-Doubs circuit and we determined that this approach was not viable due to time constraints and financial considerations. PJM and TrAILCo estimate that a reconductoring of the Mt. Storm-Doubs line would require approximately five years. This estimate is based on the length of the line, estimates of the duration of continuous work that would be required to complete the reconductoring, and the expected inability to remove the circuit from service for extended periods in order to perform the necessary work, which would dramatically increase the actual construction period. The Mt.

Storm-Doubs 500 kV transmission line runs directly parallel to the Bedington-Black Oak 500 kV transmission line, in West Virginia. The Bedington-Black Oak interface is constrained every month of the year and this interface typically experiences the highest monthly congestion cost of any facility on the PJM transmission system. This constraint occurs because NERC standards mandate the line should not exceed its emergency rating for the contingency loss of the Mt. Storm-Doubs circuit. The existence of this constraint currently requires PJM to apply operational restrictions in order to maintain system reliability.

Due to the limited transmission capability on the Bedington – Black Oak and Mt. Storm-Doubs circuits, PJM must regularly run generation out of "merit order" in the east. This results in reliance on more costly eastern generation, than the western generation, which is generally less expensive. Eastern generation must be run in order to manage the constraint by reducing the typical flow on these lines.

Under the present conditions, the congestion on this interface, with the Mt. Storm-Doubs circuit in service, costs tens of million dollars per month in the non-summer months. An extended outage of the Mt. Storm-Doubs circuit would put significant additional stress on the remaining transmission facilities through this corridor. In order to maintain reliable operations with the Mt. Storm-Doubs circuit removed from service for this extended period, PJM would have to run significantly more eastern generation, out of merit order, than it already runs. This would result in

significantly higher congestion costs. A five-year outage during non-summer months alone could easily result in well over one billion dollars in congestion costs.

Further, reconductoring the Pruntytown-Mt. Storm circuit at the same time would require the removal of both circuits and would place additional operational stress on the system. The outage of Pruntytown-Mt. Storm is even more critical than the outage of Mt. Storm-Doubs and in fact, it may be impossible to take both lines at the same time.

Another alternative option is double circuiting the Mt. Storm-Doubs and Pruntytown-Mt. Storm circuits. This would be a more substantial project than TrAIL or a reconductoring of those same circuits. Such a project would take as long as or longer than a reconductoring project with all of the same operational reliability risks and congestion costs. Further, PJM would need to perform NERC Category C analyses related to the tower line outages that would now exist on the two 500 kV paths. Therefore this is not a viable solution.

Q. PLEASE COMMENT WITH REGARD TO WITNESS KLEIN'S TESTIMONY THAT THERE ARE NEW TECHNOLOGICAL IMPROVEMENTS THAT CAN ADRESS THE RELIABILITY CONCERNS ASSERTED BY TRAILCO.

ECC Cross Exam Ex 5
MAR 25 2008 Pgh St A-110172

TrAILCo Response to ECC Interrogatory Set III, No. 9
Sponsor: Steven Herling
Response Date: September 21, 2007

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY
PaPUC Docket No. A-110172 et al.

ENERGY CONSERVATION COUNCIL OF PENNSYLVANIA Set III, No. 9:

ECC-III-9. *Regarding Herling testimony at p. 7, lines 3-7 – Describe what is meant by the* phrase, "system enhancements that will assure reliability and access by load to efficient power supply," and describe where the latter takes over from the former?

RESPONSE:

The phrase "system enhancements that will assure reliability and access by load to efficiency power supply" refers to transmission system upgrades that are needed to ensure compliance with reliability criteria, to resolve operational performance problems, or to enhance the economic efficiency of the operation of the grid. Criteria related to economic efficiency apply in situations where reliability issues are not present or where more robust transmission upgrades are proposed than would be required to resolve reliability issues.

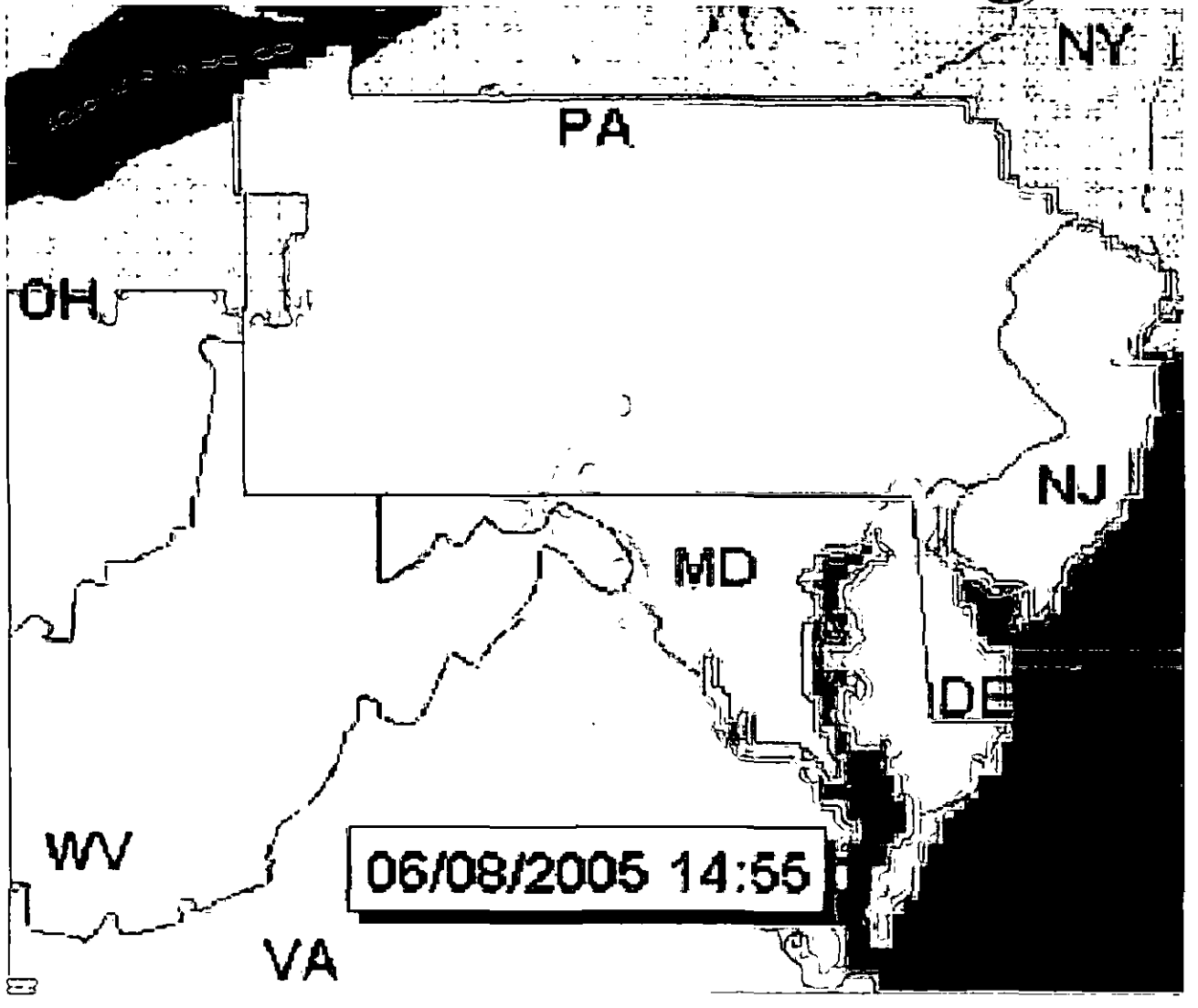
Allegheny Power
an Allegheny Energy company

EHS Meeting
June 23, 2006

TrAIL Project
&
The EHV Expansion

Safety - First & Foremost

Transmission Congestion Effects



LMP Price Range

(Locational Marginal Price)

Blue	$0 - $50
Green	$50 - $100
Yellow	$100 - 130
Orange	$130 - $170
Red	$170 - $500
Pink	$500 - $900+

TrPA-ECC-00982492

PROPRIETARY INFORMATION

Docket Number A-110172

Name of Document Allegheny Power and AEP Proposed Transmission Line Projects

Date Document Received 3-25-2008

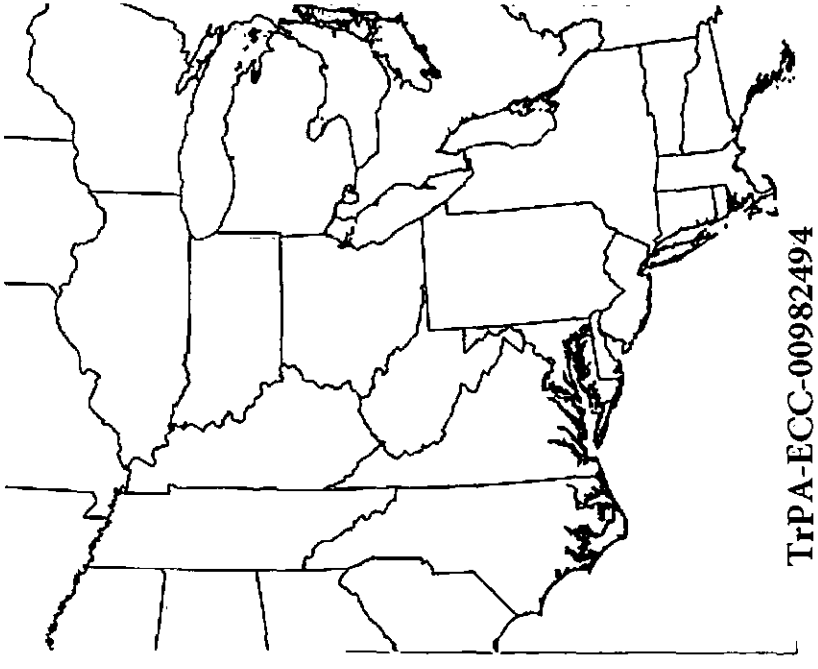
DOCUMENT CONTAINS

PROPRIETARY INFORMATION

PJM RTEP

(Regional Transmission Expansion Plan)

- RTEP process
  - Identify transmission upgrades necessary for the operational, economic, and reliability requirements
  - Current planning horizon is 5 years
  - PJM is extending the planning horizon to 15 years for facilities 230 kV and above.



TrPA-ECC-00982494

ECC Cross Exam Ex 7
MAR 2 5 2008 Pgh FX
A-110172

pjm

Generator Deliverability Results for Category 3 Generation In Dominion

Introduction

The Dominion generator deliverability results that were released on May 1, 2005 did not include results for Category 3 generation.

- Category 1 generation - generators in the Dominion Control Area that were in service and have or had firm delivery rights anytime before May 1, 2005.
- Category 2 generation - generators in the Dominion Control Area that were in service but never had firm delivery rights anytime before May 1, 2005.
- Category 3 generation - generators in the Dominion Control Area that executed an Interconnection Agreement but were not in service as of May 1, 2005.

All remaining generators currently in the interconnection queue within the Dominion service territory will be studied through the PJM interconnection process.

Results

PJM performed a generator deliverability analysis of Category 3 generators.

The following generation is not deliverable due to thermal overloads on the Brister – Ox 500 kV circuit for the outage of the Morrisville – Loudoun 500 kV circuit, Morrisville – Loudoun 500 kV circuit for the outage of the Brister – Ox 500 kV circuit and Mt. Storms – Doubs circuit for the outage of the Mt. Storm – Meadow Brook 500 kV circuit.

Queue Position	Name	MW	Deliverability
GI-56	Bath County 1,3,4,6	340	Not Deliverable
GI-86	Warren County	550	Not Deliverable
GI-102	Waverly	750	Not Deliverable
GI-119	North Anna	40	Not Deliverable
GI-120	Surry	30	Not Deliverable
GI-141	North Anna	130	Not Deliverable
GI-144	Buckingham	625	Not Deliverable

ECC Cross Exh. 8
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A-110172

Virginia Electric and Power Company
Case No. PUE-2007-00031
Piedmont Environmental Council
Second Set

The following response to *Interrogatory Question* No. 62 of the First Set of Interrogatories and Requests for Production of Documents of Piedmont Environmental Council received on May 21, 2007 has been prepared under my supervision as it concerns the PJM RTEP.

Steven R. Herling
Vice President of Planning
PJM Interconnection, L.L.C.

Question No. 62

a. Were any new generating units, and of what capacity, assumed to be built in Virginia, Maryland, and the Delmarva Peninsula in conducting the 2011, 2012, and 2016 studies?

b. If the answer to subpart (a) is "yes," then identify those new generating units, including their assumed location, in-service date, and capacity.

Response:

a. Yes.

b. These are the generators not yet in service located in Maryland, Virginia and the Delmarva Peninsula.

Queue	Location	Projected In-Service Date	MW Capacity (C) / MW Energy (E)
G51 W62	Maryland	2009 Q2	640 C
K28 + H23 W70	Maryland	2008 Q4	19.8 C / 80.2 E
K25 + I03 W74	Maryland	2009 Q4	8 C / 32 E
N07	Virginia	2008 Q3	7.6 C / 30.4 E
N29	Maryland	2008 Q4	8 C / 32 E

All the generators listed above were included in the 2016 basecase. The K28 generator was included in the 2011, 2012, and 2016 basecases.

ATTACHMENT ECC-IA-9-Y

ECC Cross Exam Ex 8-A
MAR 25 2008 Pg/h PK A-110172

Virginia Electric and Power Company
Case No. PUE-2007-00031
Piedmont Environmental Council
Second Set

The following **revised** response to *Interrogatory Question* No. 62 of the Second Set of Interrogatories and Requests for Production of Documents of Piedmont Environmental Council received on May 21, 2007 has been prepared under my supervision as it concerns the PJM RTEP.

Steven R. Herling
Vice President of Planning
PJM Interconnection, L.L.C.

Question No. 62

a. Were any new generating units, and of what capacity, assumed to be built in Virginia, Maryland, and the Delmarva Peninsula in conducting the 2011, 2012, and 2016 studies?

b. If the answer to subpart (a) is "yes," then identify those new generating units, including their assumed location, in-service date, and capacity.

Response:

a. Yes.

b. The following tables list the future generation studied in 2011, 2012 and 2016, respectively, across all of PJM.

Future Generation Modeled in 2011 Basecase:

Queue Name	Projected In-Service Date	Location	MW - Capacity	MW - Energy
A54		PA	45	0
C01	5/1/2006	NJ	436	0
C02	1/1/2007	PA	47	0
G06	12/1/2007	PA	30	0
G07		PA	100	0
G30_W51	6/1/2008	WV	600	0
G51_W60	12/31/2008	PA	525	0
G51_W62	6/30/2010	MD	640	0
I13	9/1/2007	PA	0	36
J07	11/1/2006	WV	0	155
K02	11/1/2007	PA	0	70
K07_CE20	12/31/2007	IL	31.6	158
K11	9/30/2007	WV	60	300
K13	9/1/2007	PA	6.8	0
K25	11/15/2007	MD	8	0
K26	11/1/2006	WV	31	0
K28	11/6/2006	MD	19.8	0
L05_CE22	9/1/2006	IL	30	150
L12_CE23	1/1/2007	IL	4	20
L13_CE26	10/30/2006	IL	35	175
L13	12/31/2007	PA	8	40
L19	6/30/2008	PA	290	0
M11	7/1/2008	PA	111	0
M12	7/1/2007	PA	107	0
M22	2/1/2008	PA	125	0
M23	12/1/2006	WV	30	150
M24	11/1/2007	WV	37.2	186
M26	5/31/2008	PA	272	0
M28	1/1/2008	IL	600	0
N07	9/1/2008	VA	7.6	38
N09	3/31/2008	WV	90	0
N12	1/1/2008	OH	75	75
N14	6/1/2006	PA	4.8	24
N15	5/1/2008	IL	30	150
N27	7/1/2006	NJ	4	0
N29	12/31/2008	MD	8	40
N30	12/31/2006	PA	0	5
N31	7/31/2007	PA	0	5
N32	12/1/2006	PA	12	60
N33	12/1/2008	WV	12	60
N36	11/1/2008	PA	10	50
N39	11/1/2006	PA	16	80
N47	12/15/2008	WV	27	135

ATTACHMENT ECC-IA-9-Y

Future Generation Modeled in 2012 PJM Basecase:

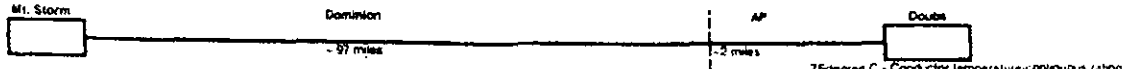
Queue Name	Projected In-Service Date	Location	MW - Capacity	MW - Energy
C01	5/1/2006	NJ	436	0
C02	1/1/2007	PA	47	0
G06	12/1/2007	PA	30	0
G07		PA	100	0
G30_W51	6/1/2008	WV	600	0
G46	10/1/2007	PA	70	0
G51_W60	12/31/2008	PA	525	0
G51_W62	6/30/2010	MD	640	0
H17	6/1/2008	NJ	115	0
H18	12/1/2007	NJ	78	0
H19	12/1/2007	NJ	43	0
I13	9/1/2007	PA	0	36
J07	11/1/2006	WV	0	155
K02	11/1/2007	PA	0	70
K07_CE20	12/31/2007	IL	31.6	158
K11	9/30/2007	WV	60	300
K13	9/1/2007	PA	6.8	0
K25	11/15/2007	MD	8	0
K26	11/1/2006	WV	31	0
K28	11/6/2006	MD	19.8	0
L05_CE22	9/1/2006	IL	30	150
L12_CE23	1/1/2007	IL	4	20
L13	12/31/2007	PA	8	40
L19	6/30/2008	PA	290	0
M11	7/1/2008	PA	111	0
M12	7/1/2007	PA	107	0
M23	12/1/2006	WV	30	150
M24	11/1/2007	WV	37.2	186
M26	5/31/2008	PA	272	0
N07	9/1/2008	VA	7.6	38
N09	3/31/2008	WV	90	0
N12	1/1/2008	OH	75	75
N14	6/1/2006	PA	4.8	24
N15	5/1/2008	IL	30	150
N21	1/1/2007	IL	2.2	11
N22	1/1/2007	IL	2.2	11
N23	1/1/2007	IL	2.2	11
N24	1/1/2007	IL	2.2	11
N25	1/1/2007	IL	2.2	11
N27	7/1/2006	NJ	4	0
N29	12/31/2008	MD	8	40
N32	12/1/2006	PA	12	60
N33	12/1/2008	WV	12	60
N36	11/1/2008	PA	10	50
N39	11/1/2006	PA	16	80
N41	5/1/2010	WV	1200	0
N42	5/1/2010	OH	600	0
N47	12/15/2008	WV	27	135
O11	6/1/2007	NJ	7.1	0
O20	12/31/2006	NJ	9.6	0
O25	3/1/2007	MD	6	6
O26	1/1/2007	PA	8	0
O31	12/31/2006	VA	5.21	0
O32	6/30/2007	WV	25	0
O42	12/31/2006	MI	84	0
O43	6/1/2005	IL	54	0
O46	12/1/2007	PA	0.4	2
O53	9/15/2006	PA	81	0
O54	10/23/2006	PA	77	0

Future Generators Modeled in PJM 2016 Basecase:

Queue Name	Projected In-Service Date	Location	MW - Capacity	MW - Energy
A54		PA	45	0
C01	5/1/2006	NJ	436	0
C02	1/1/2007	PA	47	0
G06	12/1/2007	PA	30	0
G07		PA	100	0
G30_W51	6/1/2008	WV	600	0
G51_W60	12/31/2008	PA	525	0
G51_W62	6/30/2010	MD	640	0
I13	9/1/2007	PA	0	36
J07	11/1/2006	WV	0	155
K02	11/1/2007	PA	0	70
K07_CE20	12/31/2007	IL	31.6	158
K11	9/30/2007	WV	60	300
K13	9/1/2007	PA	6.8	0
K25	11/15/2007	MD	8	0
K26	11/1/2006	WV	31	0
K28	11/6/2006	MD	19.8	0
L05_CE22	9/1/2006	IL	30	150
L12_CE23	1/1/2007	IL	4	20
L13_CE26	10/30/2006	IL	35	175
L13	12/31/2007	PA	8	40
L19	6/30/2008	PA	290	0
M11	7/1/2008	PA	111	0
M12	7/1/2007	PA	107	0
M22	2/1/2008	PA	125	0
M23	12/1/2006	WV	30	150
M24	11/1/2007	WV	37.2	186
M26	5/31/2008	PA	272	0
M28	1/1/2008	IL	600	0
N07	9/1/2008	VA	7.6	38
N09	3/31/2008	WV	90	0
N12	1/1/2008	OH	75	75
N14	6/1/2006	PA	4.8	24
N15	5/1/2008	IL	30	150
N27	7/1/2006	NJ	4	0
N29	12/31/2008	MD	8	40
N30	12/31/2006	PA	0	5
N31	7/31/2007	PA	0	5
N32	12/1/2006	PA	12	60
N33	12/1/2008	WV	12	60
N36	11/1/2008	PA	10	50
N39	11/1/2006	PA	16	80
N41	5/1/2010	WV	1200	0
N42	5/1/2010	OH	1200	0
N47	12/15/2008	WV	27	135

FCC Cross Exam Ex 9
MAR 2 5 2008 Pgh PX A-110172

Mt. Storm - Doubs 500kV Line Rating Information



Rating Methods:

Dominion: 81degree C - Conductor Temperature; 3 ft/sec wind speed; 100 degree F Ambient Temperature

AP: 75degree C - Conductor temperature-continuous rating; 92degree C- Conductor temperature-Emergency rating; 2 mph wind speed; 90 degree F Ambient Temperature

Planning Criteria:	Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
Dominion (Summer Clearance Limited for Conductor)				
100 degree F	2598 MVA	2598MVA		
50 degree F			3464MVA	3464MVA

AP (Summer Conductor Limited)	Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
90 Degree F	2564MVA	3300MVA		
50 Degree F			3293MVA	3464MVA

Coordinated Tie Line Ratings (Planning)
AP - Dominion

	Summer Continuous	Summer Emergency	Winter Continuous	Winter Emergency
Mt Storm - Doubs Total	2564MVA	2598MVA	3293MVA	3464MVA

Dominion Loadability as of June/2006

	Continuous	Emergency
100 F	2598MVA	2598MVA
95 F	2704MVA	2704MVA
86F	2682MVA	2682MVA
77F	3048MVA	3048MVA
68F	3204MVA	3204MVA
59F	3352MVA	3352MVA
50F	3464MVA	3464MVA
41F	3464MVA	3464MVA
32F	3464MVA	3464MVA

Allegheny Loadability as of December 28, 2007

	Continuous	Emergency
100 F	N/A	N/A
95 F	2564MVA	3300MVA
86F	2650MVA	3436MVA
77F	2827MVA	3464MVA
68F	2991MVA	3464MVA
59F	3145MVA	3464MVA
50F	3293MVA	3464MVA
41F	3431MVA	3464MVA
32F	3464MVA	3464MVA

December 13, 2007 Dominion Oasis Information
(Note: Data can change daily for system conditions)

	Norm	Long	Short	Dump
95 F	2702MVA	2704MVA	2704MVA	2788MVA
86F	2606MVA	2882MVA	2882MVA	2972MVA
77F	2910MVA	3048MVA	3048MVA	3143MVA
68F	3014MVA	3196MVA	3196MVA	3296MVA
59F	3116MVA	3300MVA	3300MVA	3402MVA
50F	3196MVA	3377MVA	3377MVA	3482MVA
41F	3300MVA	3464MVA	3464MVA	3572MVA
32F	3403MVA	3464MVA	3464MVA	3572MVA

December 13, 2007 Allegheny Oasis Information
(Note: Data can change daily for system conditions)

	Norm	Long	Short	Dump
95F	2564MVA	2910MVA	2910MVA	3000MVA
86F	2650MVA	2910MVA	2910MVA	3000MVA
77F	2827MVA	2910MVA	2910MVA	3000MVA
68F	2910MVA	2910MVA	2910MVA	3000MVA
59F	2910MVA	2910MVA	2910MVA	3000MVA
50F	2910MVA	2910MVA	2910MVA	3000MVA
41F	2910MVA	2910MVA	2910MVA	3000MVA
32F	2910MVA	2910MVA	2910MVA	3000MVA

January 17, 2007 Real Time PJM EMS (Dominion) Information
(Note: Data can change daily for system conditions)

	Norm	Long	Short	Dump
95 F	2702MVA	2704MVA	2704MVA	2788MVA
86F	2682MVA	2882MVA	2882MVA	2972MVA
77F	3048MVA	3048MVA	3048MVA	3143MVA
68F	3204MVA	3204MVA	3204MVA	3304MVA
59F	3352MVA	3352MVA	3352MVA	3456MVA
50F	3464MVA	3464MVA	3464MVA	3572MVA
41F	3464MVA	3464MVA	3464MVA	3572MVA
32F	3464MVA	3464MVA	3464MVA	3572MVA

January 17, 2007 Real Time PJM EMS (Allegheny) Information
(Note: Data can change daily for system conditions)

	Norm	Long	Short	Dump
95F	2564MVA	3300MVA	3300MVA	3518MVA
86F	2650MVA	3436MVA	3436MVA	3644MVA
77F	2827MVA	3464MVA	3464MVA	3712MVA
68F	2991MVA	3464MVA	3464MVA	3712MVA
59F	3145MVA	3464MVA	3464MVA	3712MVA
50F	3293MVA	3464MVA	3464MVA	3712MVA
41F	3431MVA	3464MVA	3464MVA	3712MVA
32F	3464MVA	3464MVA	3464MVA	3712MVA

ECC Cross Exam Ex 10
MAR 2 5 2008 Pa PK A-110172

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SECRETARY'S BUREAU

NEWS
RELEASE

FOR IMMEDIATE RELEASE

PJM RELIABILITY PRICING MODEL AUCTION DRAWS LARGEST AMOUNT OF NEW CAPACITY SO FAR

(Valley Forge, Pa. – Feb. 1, 2008) – The fourth PJM Interconnection base residual auction for capacity using the Reliability Pricing Model (RPM) continued the trend of increased generation and demand resources available to serve consumers. Results of the fourth auction, which was for the planning year June 2010 through May 2011, were posted today.

"For this auction by itself we saw the largest net increase in capacity since we began the RPM auctions," said Andrew L. Ott, PJM vice president-Markets. "We added a net 1500 megawatts of resources."

"Looking at the combined results of the four base auctions, the net minimum increase in capacity was 10,000 megawatts compared to what would have been available absent RPM," Ott added. "In other words, there will be 10,000 megawatts of capacity ready to keep the lights on for consumers that wouldn't have been there without RPM."

The recent auction produced a clearing price for most of the PJM region of $174.29 per megawatt-day. The clearing prices for the previous delivery year, 2009-2010, were $237.33 in the Baltimore-Washington area, $191.24 in the Mid-Atlantic region and $102.04 in the western portion of the PJM market area.

Prices were reduced in the Baltimore-Washington and Mid-Atlantic areas and increased in the western portion of the region due to capacity exports and load growth.

RPM sends price signals that attract resources to the areas where they are most needed. Capacity prices can vary by region depending on capacity supplies and transmission capacity. In this auction, only the Delmarva Peninsula south of the Chesapeake and Delaware Canal was constrained. The RPM clearing price there is $186.12.

"Customers' use of electricity continues to grow every year, but the addition of new capacity to provide electricity for them has slowed," Ott said. "RPM provides the needed incentive to add more generation and demand response and to retain existing generation."

– MORE –

Contact: PJM News, toll free at 866-PJM-NEWS (756-6397)

The RPM ensures that electricity providers have enough capacity—power to be drawn from when needed—to reliably serve the 51 million people in the PJM region. PJM members that sell electricity to end-use customers must have access to adequate power supplies. They can use generation, transmission or demand response, including energy-efficiency programs. They can meet their supply requirements by owning resources (self-supply) or contracting for them (bilaterals).

The RPM auctions procure capacity needed after participants have specified self-supply and contracted (bilateral) resources. The next base residual auction will be in May 2008. It will be for the delivery year 2011-2012.

Capacity prices are paid by electricity providers at a wholesale level, and the price that is passed through to retail consumers differs by company.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes 6,038 substations and 56,250 miles of transmission lines; administers a competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. Visit PJM at www.pjm.com.

###

ECC Goss Exam Ex 11
MAR 2 5 2008 Pgh PKA-110172

Craig A. Glazer
Vice President - Governmental Policy
PJM Washington Office
(202) 393-7756 .FAX (202) 393-7741
e-mail: glazec@pjm.com

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SECRETARY'S BUREAU

May 12, 2005

The Honorable Magalie R. Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, N.W.
Washington, D.C. 20426

Re: FERC Docket Nos. AD05-5-000, PL03-1-000

Dear Ms. Salas:

Enclosed is the testimony of Karl Pfirrmann, President, PJM Interconnection, L.L.C. Western Region for the Technical Conference to be held May 13, 2005.

Please call me at 202-423-4743 with any questions concerning this filing.

Sincerely,

Craig Glazer

Craig Glazer

Vice President,
Federal Government Policy
PJM Interconnection, L.L.C.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Promoting Regional Transmission Planning And Expansion to Facilitate Fuel Diversity Including Expanded Use of Coal-Fired Resources	Docket No. AD05-3-000

EXECUTIVE SUMMARY OF REMARKS OF KARL PFIRRMANN PRESIDENT, PJM WESTERN REGION PJM INTERCONNECTION, L.L.C.

In his testimony before the Commission's Technical Conference on fuel diversity and expanded use of coal-fired resources, PJM Western Region President Karl Pfirrmann details the accomplishments of the Commission and the states in the region in opening up markets for coal-based resources. He then outlines a potential "road map", dubbed "Project Mountaineer", to further enhance opportunities for interregional trade. Mr. Pfirrmann describes, by way of example, the potential for new transmission resources in the region to enhance opportunities for coal based generation to reach eastern markets. His testimony outlines the benefits to the coal region of such interregional trading and then describes some of the regulatory and environmental challenges that the region must tackle. He pledges PJM's commitment, working through its transparent and open regional transmission planning process, to explore these issues in further detail.

PJM serves as the Commission-approved Regional Transmission Organization ("RTO") in a thirteen state region which includes all or part of the states of West Virginia, Kentucky, Virginia, Tennessee, Ohio, Indiana, Illinois, North Carolina and Michigan as well as the mid-Atlantic states of New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia. As the RTO, PJM serves as both the "air traffic controller" ensuring the reliability of the high voltage grid as well as the operator of a robust competitive and transparent wholesale market for electricity. Coal-fired generation accounted for over 56% of the electricity produced for PJM in 2004.

Mr. Pfirrmann's testimony outlines three key points:

1. *The "R" in "RTO" means benefits for this region*---The integration of American Electric Power ("AEP"), Allegheny Energy, Commonwealth Edison, Duquesne, Dayton Power and Light and Dominion into PJM, most of which occurred during the last several months, has *already* increased market opportunities for this region's

generation resources. Interregional power flows have increased by approximately 35%, representing off-system sales that potentially benefit *both* the mid-Atlantic region and the consumers in this area;

2. **<u>*An unprecedented level of interregional coordination has commenced*</u>--- The agreements reached between PJM and the Midwest ISO, as well as between these two entities and TVA have established the foundation for an unprecedented level of coordinated planning and interregional coordination;**

3. **<u>*"Project Mountaineer" is an example of how the region can take coordinated regional planning to the next level*</u>---By way of example, PJM outlines the scope of transmission projects that would be needed to significantly enhance the ability of coal based resources to reach eastern markets. Transmission enhancements include potentially 550 to 900 miles of new backbone 500 or 765 kv transmission at an approximate cost of $3.3 to $3.9 billion. Although a large number, if such costs are spread to all customers within the PJM footprint, the cost to a typical retail customer would amount to only one mill/kwh.**

In closing, PJM pledges to work with the Commission, the states and transmission owners in this region as well as with other interested persons to further explore the potential for enhancing interregional trade and finding solutions that pay benefits to consumers in this region as well as throughout the Eastern Interconnection.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid; administers a competitive wholesale electricity market, the world's largest; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Promoting Regional Transmission Planning and Expansion to Facilitate Fuel Diversity Including Expanded Uses of Coal-Fired Resources

Docket No. AD05-3-000

TESTIMONY OF KARL PFIRRMANN, PRESIDENT
PJM WESTERN REGION
PJM INTERCONNECTION, L.L.C.

PJM Interconnection, ~~L.L.C.~~ ("PJM") is pleased to participate in the Commission's efforts to focus on regional transmission planning and its role in facilitating fuel diversity and use of coal resources. This conference is most timely. PJM is proud of what has been accomplished to date to open up new markets for coal. But no entity should just rest on its laurels. There is much more that we and others in this region can do collectively. It is for this reason that today PJM is also setting out by way of example, a new initiative, which we have labeled "Project Mountaineer", to utilize our regional transmission planning process to explore ways to further develop an efficient transmission "super-highway" to bring low cost coal resources to market.

PJM serves as the FERC-approved Regional Transmission Organization ("RTO") in a thirteen state region which includes all of this great state as well as all or parts of Kentucky, Virginia, Tennessee, Ohio, Indiana, Illinois, North Carolina and Michigan as well as the mid-Atlantic states of New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia, a region of 45 million people. As the RTO, we serve as both the "air traffic controller" ensuring the reliability of the high voltage grid as well as the operator of a transparent wholesale market for electricity. Coal is a key resource in PJM, accounting for over 56% of the total electricity produced during 2004. My basic message can be summarized as follows:

1. *The "R" in "RTO" Means Benefits for This Region*---One of the functions of an RTO is to engage in regional transmission planning. Since its inception as an independent entity, PJM has a proven transparent regional planning process that has already identified over $1 billion in transmission improvements, all designed to improve the reliability and economics of power flows in this region. The recent expansion of PJM to include the AEP, Allegheny Power, Dayton, Dominion, Duquesne and Commonwealth Edison systems brings the proven benefits of PJM's regional planning process to coal country;

2. *Inter-Regional Coordination is Ongoing at the Highest Level*— PJM and MISO are working together to undertake regional planning for their combined 27 state footprint. We have joined together to pioneer an historic Joint Operating Agreement which calls for coordinated planning and cost allocation to end many of the stalemates of the past. The two entities recently signed a Memorandum of Understanding with TVA to further coordinate planning and operations activities and bring down many of the past barriers to interregional coordination. In short, PJM, MISO and TVA have not just "talked the talk", they are "walking the walk";

3. *Much Has Been Accomplished: Significant Increased Power Flows*--As a result of the expansion of PJM, we have seen dramatic increases in the amount of power flowing from this region into "classic" PJM, including from coal-based generation, as illustrated on exhibit A attached to my testimony. I should note that these power flows are a good news story for electric customers in this region. A utility's lowest cost resources first go to serve its native load customers consistent with its state service requirements. These "off system" sales represent generation, over and above that needed to serve native load, available to serve other regional demands at lower cost. Off system sales are then eligible for consideration in each company's retail ratemaking process consistent with individual state requirements;

4. *Taking Regional Planning to the Next Level: "Project Mountaineer"*-- We are today illustrating by way of example, a proposed "Project Mountaineer". Our goal is to demonstrate the possibilities that could result from a targeted cooperative effort to identify additional transmission that could be built in this region to facilitate fuel diversity and improve options for economic generation resources. At this early stage, Project Mountaineer should not be considered a proposal for any specific transmission line. Rather it reflects our commitment to utilizing our Regional Transmission Expansion Planning process involving the states, the FERC, the transmission owners in this region and affected stakeholders, to explore new transmission opportunities to improve reliability and to enhance access to markets for this region's valuable low-cost energy resources.

The balance of my testimony will explore these matters in further detail.

I. MOVING BEYOND THE PAST: REGIONAL PLANNING THAT MEETS 21st CENTURY NEEDS

The Evolution of Regional Transmission Planning

1. The Origins of Transmission Planning---From the beginning of the electric industry, transmission was always considered as a component of major generation projects. As early as Thomas Edison's development of the Pearl Street substation in New York City, transmission was developed to link local generation to local load. Rarely, if ever, was transmission constructed as a stand alone asset not linked to development of a specific planned generation project. Individual utilities each undertook their own planning processes designed to meet their individual state service obligations and their own customer needs. In short, the basis of transmission planning was not to facilitate flows between regions but rather to deliver the output of a utility's own generation to its customers.

Of course, there are some notable early examples of regional planning approaches. PJM Interconnection was formed back in 1927 as a stand alone association of transmission companies in order to manage a shared backbone system designed originally to deliver power from a hydro-electric facility along the Susquehanna River to load centers throughout Pennsylvania, New Jersey and Maryland. Later, PJM transmission owners worked collaboratively to build the 500 kV transmission system to deliver jointly owned coal and nuclear generation to customer load. By the same token, in this region, large holding companies such as AEP and Allegheny Energy sited generation in strategic locations near to the coal fields of the Ohio and Kanawha River valleys and built robust multi-state transmission systems to deliver that generation to customers as far away as Fort Wayne, Indiana and Hagerstown, Maryland. There certainly was a degree of sharing and cooperation among utilities at that time. However, for the most part, transmission was designed to serve individual utility needs.

2. Ensuring Competitive Access to the Transmission Grid---The world of transmission planning changed dramatically with Congress' passage of the Energy Policy Act of 1992. Under that law, Congress embraced wholesale competition in electricity as the law of the land, creating a whole new class of exempt wholesale generators to compete in a competitive market. EPACT as well as subsequent Orders of this Commission, including its landmark Orders 888 and 2000 opened the transmission grid to competitors allowing merchant generation to have the same rights to access the transmission grid as the utility's own generation. In short, transmission was treated like the interstate highway system, providing open non-discriminatory access to all users.

In moving to embrace competition the challenge remained to ensure that the system served the region reliably while still meeting local needs. PJM undertook to meet this challenge from its inception as an independent organization in the late 1990's. The states in the original PJM mid-Atlantic region insisted that PJM move forward with establishing a regional planning process prior to instituting competitive wholesale markets. That process has grown over time to become recognized as one which is robust and transparent. The PJM planning process takes a "big picture" look to ensure that there is sufficient transmission infrastructure to meet projected reliability needs and to relieve congestion in areas where market solutions do not arise. The states are involved in this planning process. To date, over $1 billion of transmission investment has either been constructed or is under development as a result of PJM's planning process. An outline of that process and the "next steps" associated with its further development are outlined in the testimony of my colleague Audrey Zibelman which is attached to this testimony.

II. ENHANCING INTERREGIONAL POWER FLOWS: SUCCESSES TO DATE

The Expanding PJM Footprint Has Increased West to East Power Flows

Although American Electric Power, Dayton, Dominion, Duquesne, and Commonwealth Edison have only been in PJM for less than one year (and in the case of Dominion, only since May 1 of this year), we have already seen a dramatic increase in west to east power flows. Specifically, as a result of these companies joining a Regional Transmission Organization, many of the constraints that served to adversely impact power flows have been internalized---redispatch of generation in response to locational marginal pricing has been used to manage congestion on transmission lines rather than simply curtailing transactions. Secondly, and perhaps most notably, this Commission has eliminated the "through and out" rates between AEP and Commonwealth Edison on one side and PJM on the other as well as between the Midwest ISO and PJM regions as a whole. These "through and out rates" served as a significant barrier to the economical flow of coal-based energy to eastern markets. They acted as artificial toll gates, adversely impacting the economics of coal based resources in this region compared to sources of generation which happened to be located on the other side of the "toll gate". The Commission should be applauded for taking this groundbreaking step.

Our Joint Operating Agreement with the Midwest ISO as well as our Joint Reliability Coordination Agreement among the Midwest ISO, PJM and TVA serve as a key third leg of the stool. These agreements and the development of a joint and common market between the very large PJM and MISO control areas will work to improve reliability, enhance regional

trading and allow us to plan optimal transmission solutions irrespective of whether a particular company is a member of PJM or the Midwest ISO or within the TVA footprint.

III. THE NEXT STEP: "PROJECT MOUNTAINEER"

The Commission has properly asked what are the present impediments to additional interregional trading. I would like to take a moment to outline some of those impediments and a potential solution: an intensive stakeholder effort to further strengthen the region's transmission backbone and provide support for harnessing this region's efficient low cost generation to meet our economy's growing demand for power. We have dubbed this initiative "Project Mountaineer". I wish to be very clear. The project is not to be seen as specific wires and towers at this point, but rather a targeted effort to use our regional planning tools to identify the region's need in a comprehensive manner across a very large footprint. The goal is to focus on all aspects of harnessing the existing and planned generation in this region to meet the needs of the broader PJM market. And because the process is undertaken by PJM in the context of its approved independent regional transmission planning process, we view this effort as one where facts and figures will prevail so as to limit claims that the data represents just the economic interests of a particular group of stakeholders.

A. Present Impediments to West/East Trade

Although west to east power flows have increased by approximately 35% since the integration of Allegheny, AEP, Commonwealth Edison, Dayton, and Duquesne into PJM, there remain certain physical constraints on the transmission system that have limited further flows of coal based generation to markets in the east. These constraints are depicted on Exhibit B and principally exist at three locations:

The Wylie Ridge transformers and Sammis-Wylie Ridge transmission line at the AEP/APS/FE interface;
The Bedington/ Black Oak 500 kV transmission line within the APS system; and
The PJM Eastern Interface along the Delaware River, separating Pennsylvania and New Jersey.

B. Key Features of Project Mountaineer

In order to set forth by way of example potential resolutions of these constraints on west/east power flows, PJM has undertaken a preliminary delineation of the magnitude of the transmission improvements that are needed to enhance power flows by up to 5,000 MW. As Exhibit C indicates, to meet this targeted increase in power flows, two or more new backbone 500 kv and 765 kv transmission paths of approximately 550 to 900 miles in length will need to be constructed from Kentucky and West Virginia to eastern load centers stretching from Washington, D.C. to northern New Jersey. Although there is some existing right of way associated with existing facilities which could be upgraded to handle lines of this magnitude, a great deal of new right of way will be needed. PJM estimates the cost of this new transmission to range from approximately $3.3 to $3.9 billion. Although this is clearly a costly undertaking, it is worth noting that one study recently translated $ 4 billion in new transmission investment to equate to only 1 mill/kwh on a typical residential bill if such costs were spread across the entire PJM footprint.[1]

C. Project Mountaineer's Challenges

There remain considerable challenges to construction of transmission of this magnitude. I raise these challenges not to indicate that the initiative is not worth undertaking, but rather to ensure that we all have a realistic assessment of issues we will need to overcome as a region. The challenges which construction of this magnitude will face fall into a number of categories. I have outlined them below along with potential solutions for each:

1. Siting - High voltage transmission to move power from the coal fields of Ohio, Kentucky and West Virginia to markets along the eastern seaboard will require the siting approval of anywhere from three to six states. Consistent with individual state siting laws, each state will need to address and balance the need for the facility with its attendant environmental impact. For this siting process to be successful, it is critical that states work together, to look at not just individual state impacts but the benefits for the region as a whole in strengthening the interstate electric grid. As we all know too well, any one state can slow down the siting process. In order to ensure an orderly approach, we envision the PJM Regional Transmission Expansion Planning process as providing a forum where states can come together to work through issues associated with the need for these transmission facilities and help to craft multi-state solutions. Each state's sovereignty over the siting process would be respected but the critical

[1] "PJM – The Need for Interstate Bulk Power Transmission System Expansion", George E. Owens, P.E., Downes Associates, Inc., presented on April 20, 2005 to the Maryland Public Service Commission.

information and a forum for development of regional solutions would be available for states within the PJM footprint.

2. Environmental Issues - We need to be especially proactive to address the land use challenges that may arise with construction of this magnitude. We may need to address difficult issues associated with traversing national forest land and other protected areas. We will need to collectively find routes that are the least damaging to the environment of this region. And we will need to be cognizant that any new transmission line of this magnitude will traverse difficult terrain---mountainous areas where there could be considerable construction challenges as well as more urban areas as we move closer into eastern PJM. In short, we need to go about this process wisely and with considerable planning and forethought, including consideration of advanced technology options to mitigate environmental siting impacts, where feasible and to the extent possible. For any such initiative to be successful, public acceptance and ensuring minimal environmental disruption will be critical.

3. Cost Recovery - One of the first issues that policymakers raise is "who pays?" In resolving this issue, we have the benefit of a body of existing precedent within PJM. Through our regional planning process and with FERC's oversight, we have addressed the appropriate rules for allocating costs associated both with economic and reliability upgrades to the transmission system. By way of example, as an independent entity with expertise and a proven track record, PJM can identify the portion of these transmission facilities which are attributable to enhancing overall regional reliability (and whose costs would therefore be spread among all customers in the affected areas) vs. those portions of the line which are needed for economics for which identified beneficiaries would shoulder the cost burden, or can be attributed to the interconnection requirements of specific generating facilities. Although these decisions are by definition judgmental, the existence of a proven body of precedent, PJM's independence and transparency and FERC oversight all provide appropriate checks and balances. Given the magnitude of any such line, we envision that the stakeholder process envisioned under Project Mountaineer would consider the results of applying these cost allocation principles and also work with the states in this region to explore other alternatives to lower the financing costs associated with the construction of these facilities.

4. Coordination Among Transmission Owners - At the beginning of this testimony, I noted that, prior to RTOs, planning was characterized by individual utility efforts with more limited regional coordination. The existence of an independent entity such as an RTO changes that dynamic and opens up new opportunities for cooperative approaches to ownership of transmission. PJM is presently proposing a consortium approach among transmission owners to address issues associated with aging infrastructure.

Through the consortium approach, individual entities come together to utilize their collective buying power and needs to ensure adequate infrastructure across the entire region. There is no reason a similar consortium approach could not be explored under the umbrella of Project Mountaineer. For example, public power entities have expressed interest in ownership of transmission facilities. States in the west are considering state financing of transmission. There are a variety of creative ownership mechanisms that would be explored to avoid a few entities having to take all of the risk and bear all of the cost associated with this massive construction project. The PJM planning process would provide a forum for exploring these consortium approaches.

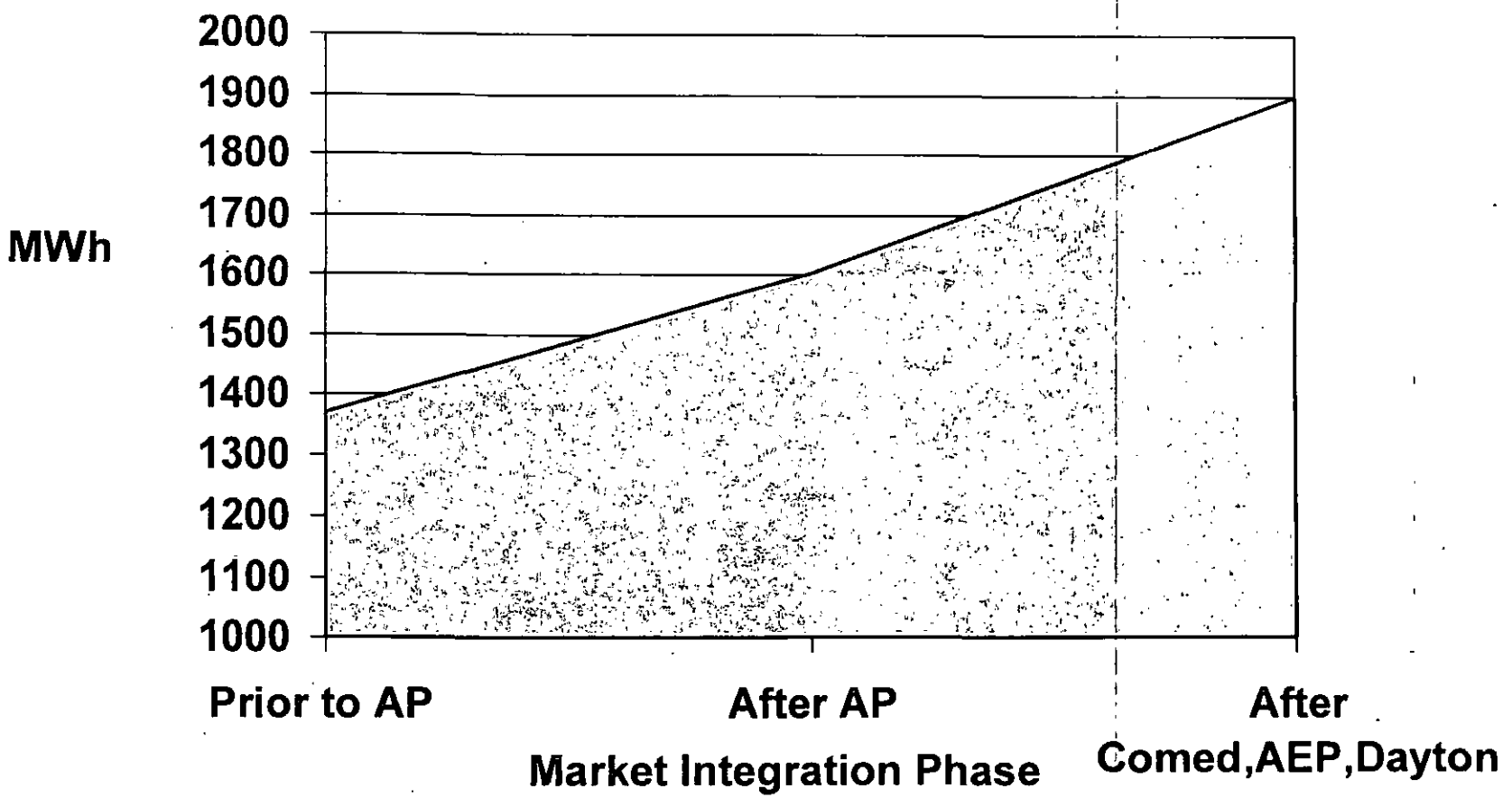
D. Project Mountaineer: Next Steps

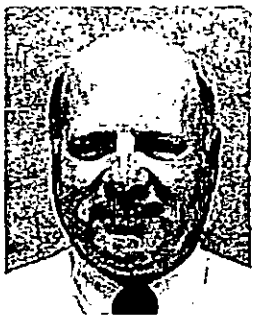
The hallmark of PJM has been its use of open stakeholder processes to address issues which defy individual solutions. Through this process, we have identified over 200 changes to PJM's Operating Agreement almost all but a handful of which have been made through a collaborative process that have resulted in endorsement by our members. We believe that the PJM stakeholder process, as well as dialogue with the newly formed Organization of PJM States, could provide excellent vehicles for further exploration and development of this project. Our collective efforts should not end there. We pledge to work with each of the state economic development entities, the coal industry as well as the utilities in this area who have committed to significant new investment in coal based generation for this region. All of these efforts would be reported to the Commission which can monitor progress.

A Regional Transmission Organization with the size and institutional history of PJM has already brought significant benefits to this region, enhancing reliability, increasing utilization of coal based resources and internalizing constraints. One measure of the success of our efforts, even in the short time since AEP, Commonwealth Edison, Dayton and Dominion have been members of PJM, can be seen in the increased power flows in this region. We stand ready to take our regional planning efforts to the next level---working with the states in the PJM region, the Midwest ISO, our stakeholders and this Commission to roll up our sleeves and focus on ensuring adequate transmission infrastructure to serve as a vital link for this region's clean coal generation to serve this country's needs well into the 21st century. We ask you to join us in our efforts.

Exhibit A

Average Import into MAAC Region From ECAR Region





Karl V. Pfirrmann, president of the PJM Western Region, has more than 32 years of experience in the electric utility industry. He develops, communicates and implements strategies that support the states and stakeholders in the western region and focuses on new members to PJM's existing service area.

His knowledge of the power system and the region to PJM's west are instrumental in identifying and meeting the needs of western regional customers.

Mr. Pfirrmann came to PJM in 2003 from Allegheny Power where he was vice president of energy supply. His other leadership positions at Allegheny have been in transmission planning, system operations and energy procurement. He managed the integration of Allegheny's transmission system into PJM in 2002 and has worked closely with PJM management to develop PJM growth in Maryland, Virginia and West Virginia and Ohio.

Regionally, he is an executive board member for the ECAR (East Central Area Reliability) section of the North American Electric Reliability Council (NERC). He has been active with the NERC Planning Committee, EPRI (Electric Power Research Institute), the Midwest Independent System Operator (MISO) Development Team and the Northeast ITC (Independent Transmission Company) Development Team.

A native of Cincinnati, Ohio, Mr. Pfirrmann has a bachelor of science degree in electrical engineering from Carnegie-Mellon University. He also has completed management training at the University of Idaho.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 25 million people in all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid; administers a competitive wholesale electricity market, the world's largest; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. The expected addition of several utilities to PJM will more than double its size and scope. Visit PJM at www.pjm.com.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Transmission Independence and Investment	Docket No. AD05-5-000
Pricing Policy for Efficient Operation and Expansion of the Transmission Grid	Docket No. PL03-1-000

EXECUTIVE SUMMARY OF TESTIMONY OF AUDREY ZIBELMAN, EXECUTIVE VICE PRESIDENT, PJM INTERCONNECTION, L.L.C.

In her remarks to the Federal Energy Regulatory Commission, Ms. Zibelman sets forth the "key ingredients" that are essential to creating a viable platform for enhanced transmission investment. She calls upon the industry and the FERC to avoid the pitfalls of yet another structure debate, but instead to use 21St century technologies and business acumen to rethink and retool how to enhance the grid.

Ms. Zibelman relays some of the key experiences from PJM's history which have worked to create an appropriate platform for transmission investment. By putting these elements in place, this Commission can obtain the benefits of consolidation of operations and the needed focus on transmission without the attendant difficulties associated with divestiture. These "building blocks" of a strong platform for investment include:

- A *regional planning process* which provides transparent information to the marketplace;
- *Settled and predictable business rules* including rules addressing participant funding;
- *Healthy competition* between transmission, demand side and generation solutions to achieve optimal results for customers; and
- *Enhanced regional coordination* both among RTOs and other entities.

On this latter point, she notes that just before the start of today's Technical Conference, PJM formally entered into an historic Joint Reliability Coordination Agreement with TVA and the Midwest ISO. This agreement provides for an *unprecedented level of reliability coordination and planning across a footprint*

that includes over 306,000 MW of generation serving more than 68 million customers/end users in all or parts of 25 states in the combined PJM/MISO/TVA region. The agreement builds on the Midwest ISO/PJM Joint Operating Agreement which has become a model for seams coordination among large transmission operators.

Ms. Zibelman also details additional action needed within the PJM footprint to enhance transmission investment. She sets forth five initiatives for the future:

Transforming the Economic Planning Process—As we examine reforms to the economic planning process, the Commission and the industry first needs to settle on the appropriate transmission model, be it a "minimal" system supporting generation sited close to load or a "strong" system designed to improve the competitiveness of the wholesale market;

Providing a long term financial transmission right product---Both transmission developers and load need greater certainty concerning the long term value of transmission upgrades and predictability of the costs of their supply arrangements. PJM is committed to developing such a product;

Transmission Pricing Reform---The Commission should move beyond rate of return adders and take a fresh look at the pricing of transmission. Ms. Zibelman outlines a number of options ranging from performance-based approaches to competitive auctions where incremental transmission is priced in comparison to substitutable generation and demand solutions;

Innovative Business Models for Transmission---The industry needs to develop new business models rather than focus on the structure debates of the past. She posits as a model, building on PJM's aging infrastructure consortium so as to manage transmission assets under a single business model while still respecting individual ownership rights;

Harnessing Advanced Technologies---In order to deploy advanced technology, the industry needs to consider utilizing a regional rather than company by company approach to model the costs and benefits of advanced technology deployment.

A complete text of Ms. Zibelman's remarks has been filed with the Commission in this docket and is also available on PJM's website *www.pjm.com*.

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REMARKS OF AUDREY ZIBELMAN, EXECUTIVE VICE PRESIDENT PJM INTERCONNECTION, L.L.C.

"*Those who cannot remember the past are condemned to repeat it.*"

George Santayana
The Life of Reason, 1905

PJM Interconnection L.L.C. ("PJM") is pleased to participate in this very timely Technical Conference addressing potential solutions to ensuring appropriate investment in electric transmission infrastructure. At PJM, we have been focusing on transmission investment since before the start of our markets in the late 1990's. I hope today to outline for you some of the essential "building blocks" we have put in place to create the platform for transmission enhancement and report on how they have worked. I also wish as well to candidly discuss with you what challenges we, as well as the rest of the industry face, detail what needs further work and provide you with our thoughts on future initiatives that need to be undertaken both by PJM as well as this Commission. Like the above quote, it is important that all of us base our decisions on facts, not emotion, on real experience not anecdotes and that we commit to an honest and open dialogue on what has worked and what needs further development as we work to help formulate policy direction for the future.

At the outset, we need to resolve a threshold issue. This Commission has appropriately placed all issues, including industry structure issues, on the table. Although one could posit, at least in theory, that consolidated ownership and operation of the grid may provide for an optimal model focused solely on transmission, we need not tie ourselves up on the many difficult issues raised by divestiture. For one, unless the Commission were to somehow order divestiture of the industry all at once so as to create a consolidated entity whose footprint parallels the existing interconnections, the benefits of consolidation and divestiture may elude us for some time. Through fully functioning RTOs, this Commission can obtain the *benefits of consolidation of operations and the needed focus on transmission* through a more expeditious and less perilous path than divestiture. That being said, RTO development of the future needs to occur not as a result of some regulatory mandate, but because RTOs provide the best *business* environment for the industry and the investment community to develop a robust transmission grid that meets customer needs. This testimony will discuss the needed "building blocks" i.e. what

has worked and what needs to happen to further enhance the development of the grid, at least in the 2/3rds of the country presently under RTOs.

WHAT HAS WORKED: ESSENTIAL BUILDING BLOCKS TO INCENT NEW TRANSMISSION INVESTMENT

Let me start by providing an overview of those key structural "building blocks" which are in place in PJM to incent needed transmission investment. I wish to start with this outline since we believe these building blocks are essential in any region of the country, whether or not it wishes to move to organized competitive wholesale markets. Without this necessary infrastructure in place, efforts to develop a robust regional transmission grid will have difficulty getting out of the starting gate.

Building Block #1---Providing information transparently to the marketplace through an independent regional transmission planning process

As with any prudent investment, potential investors in transmission need to obtain information to ensure that their investment will meet the customers' needs and provide value-added that justifies its up front cost. PJM's regional transmission planning process provides that critical information enabling investors as well as customers to obtain real time unbiased information concerning the state of the grid and the areas of congestion needing relief. The true credit here goes to the mid-Atlantic state commissions in the PJM region---each of which insisted that PJM establish a transparent independent planning process before moving to competitive wholesale markets. As a result of the process being undertaken by an independent entity through an open stakeholder process, customers and investors can obtain confidence in the accuracy of the data. Moreover, they can see how a given project fits within the larger regional grid and the degree to which it enhances the marketplace.

The planning process has worked to identify and require construction of needed facilities to enhance the reliability of the grid. Specifically, PJM has seen:

- $1.04 billion in new transmission investment identified through the PJM Regional Transmission Expansion Planning Process (RTEPP);
- $400 million of new transmission already constructed;
- $150 million of new transmission presently under construction;
- $470 million of new transmission presently under study through the RTEPP process;
- Approximately $220 million in congestion eliminated through reliability upgrades;
- Approximately $20 million in congestion eliminated through economic upgrades;

- Approximately 60% ($575 million) of these investments relate to reliability or economic upgrades while 40% ($467 million) relate to generator interconnection.

Building Block #2---Settled and Predictable Business Rules

We hear often from potential investors in both generation and transmission that certainty will drive investment---certainty around the process for interconnection, certainty around business rules and certainty around revenue. The PJM generation interconnection process is a good example---it is a mature process that provides certainty both in the process and in the business rules. Investors can point to settled rules with settled milestones and a track record of consistent outcomes. Since 1999, we have processed 533 generator interconnection requests. Moreover, we provide a settled and predictable process to identify the appropriate allocation of costs. Specifically, the PJM RTEPP resolves contentious "participant funding" issues up front rather than leaving them for separate litigation after the completion of the planning process. The PJM RTEPP utilizes a "but for" test to identify the true "cost causer" associated with a given investment. The process identifies whether the particular upgrade would have been needed *but for* the actions of a particular entity or set of entities. For example, if a generator interconnection to the grid causes a reliability problem (identified as a violation of NERC criteria), the generator is identified under the "but for" analysis and knows up front the cost of the upgrade needed to effectuate its interconnection. On the other hand, if the reliability violation results from load growth or other system conditions, the particular transmission zone is identified for such costs to be assigned.

By the same token, our process for reliability upgrades is a mature process and provides certainty. The process for identifying the baseline is transparent, the application of NERC and the appropriate Regional Reliability Council criteria is clear and the stakeholder process ensures that everyone can participate and provide needed input. The states, which have the ultimate siting authority, participate in the process up front and can rely on the public record developed for the identification of need. In short, a transparent and independent planning process can, if allowed to develop and mature, provide certainty to the investment community by resolving contentious participant funding issues and ensuring that reliability upgrades are identified through a transparent and predictable rather than "black box" process.

Building Block #3---Ensuring Proper Competition Between Transmission, Demand Side and Generation Solutions to Achieve Optimal Results for Customers

In order for regional planning to drive efficient outcomes, it is generally agreed that the process must allow for consideration of generation and demand side solutions in addition to transmission solutions. The challenge becomes how to incent healthy competition between these alternative investments while still recognizing the realities of vertical integration and the need to respect integrated

resource planning processes in bundled states. In the case of reliability solutions, the RTO directs the reliability upgrade while, at the same time, providing the information to the marketplace five years out to address the solution through these alternate means. In the case of economics i.e. building needed infrastructure to reduce congestion, the RTEPP provides a one year "market window" to allow for the marketplace to arrive at solutions before one defaults to the regulated transmission solution. And under our proposed Reliability Pricing Model, we are building in the opportunity for transmission to effectively compete against traditional capacity resources to ensure long term reliability. Although the response from the marketplace to our economic planning initiative has been less than robust for reasons I will explain later, we believe a structure which allows for generation, transmission and demand side to compete with one another to achieve optimal customer benefits is an essential structural building block.

Building Block #4—Enhanced Regional Coordination

Given the highly interconnected nature of the Eastern Interconnection, regional coordination needs to move beyond individual utility control areas and even RTO boundaries. The Joint Operating Agreement with the Midwest ISO commits both entities to exchange data and information, coordinate analysis of interconnection and transmission service requests, and develop a coordinated plan. Each of these actions is currently underway.

Moreover, today's announcement of a TVA/PJM/MISO Joint Reliability Coordination Agreement will take regional coordination to the next level---allowing for an unprecedented level of data sharing and coordination among these three very large entities which together comprise over 306,000 MW of generation serving more than 68 million customers/end users in 25 states as well as the Canadian province of Manitoba and the District of Columbia. These three transmission operators agreed today to prepare a triennial Coordinated Regional Transmission Planning study, to coordinate their analysis of long term firm transmission service requests, to coordinate their analysis of interconnection requests and to exchange critical data including load flow cases and planning models on an ongoing basis. For the first time, investors, loads and transmission owners will be part of a coordinated approach to planning of the grid across more than 2/3rds of the Eastern Interconnection. This information, available transparently, will allow investors to see how their potential investment fits within the larger picture so as to ensure that it truly will add value to the overall Eastern Interconnection.

GOING THE NEXT STEP: A ROADMAP FOR THE FUTURE

None of us should rest on our laurels. Despite these baseline accomplishments, we believe more needs to be done in PJM and elsewhere to provide the right atmosphere for the needed enhancement of the grid. As a result, I would like to outline for you issues that we have not satisfactorily resolved in PJM and provide you with our thinking to date on some action items and tasks for the future.

Challenge #1: Transforming the Economic Planning Process

Back in 2002, this Commission directed us to amend our planning process to address not just transmission enhancements needed for reliability but also those to support the development of a competitive wholesale market. The good news is that the economic planning process has been very successful from the perspective of providing useful information regarding transmission congestion. Our ability to evaluate congestion and develop solutions as a result of the process has improved dramatically. And the interrelationship between reliability upgrades and their effect on improving economics has now become a part of our RTEPP.

On the other hand, our economic planning process has not been successful to date with respect to stimulating independent development of transmission projects. Only five transmission projects have been submitted into the interconnection queue as a direct result of the economic planning process and each represents minimal facility upgrades. In short, while the economic planning process is sending out useful information to developers, the revenue streams and the related level of certainty available through the interconnection process do not appear, at least so far, to be sufficient to promote the development of independent transmission projects. No significant projects have been proposed through the process to date. Although we, along with the stakeholders and this Commission, toiled long and hard on tackling the many issues associated with an economic planning protocol, including issues such as the appropriate role of ITCs, when it is appropriate to defer to the market and at what point the RTO must step in, I am disappointed to report that our model in this area, has, to date, produced disappointing results.

To begin to resolve this issue, I believe we need to step back and ask some fundamental threshold questions. Do we want a "minimalist" transmission grid that essentially serves as an "add-on" facilitating the reliable movement of power from generation sited close to load? In other words, should the transmission system merely be a facilitator for a model based on local generation? Or are we looking for a strong transmission system that, by its design, links distant generation to load in order to address both economics and reliability and accommodate an array of generation alternatives from which load can choose? The "rules of the road" and the costs to build one system versus another are vastly different. However, we need to first define our expectation before we can develop the policy structure we need to meet that alternative.

In many ways, the Energy Policy Act of 1992 answered this question in favor of the strong superhighway to support a competitive generation industry. However, we find ourselves slipping back from time to time as we wrestle with difficult issues such as state vs. federal jurisdiction, "native load" protection and the cost to build this infrastructure. Assuming that we wish a strong transmission system to provide load with many options, we believe a new set of "building blocks" is needed.

Challenge #2: Providing a long term financial transmission right product

Load serving entities have argued that the uncertainties associated with congestion costs have discouraged needed investment. Although one can debate the fine points of whether congestion costs and LMP signals are working to provide the needed investment, it is also clear that a long term FTR product is needed to recognize the value of one's transmission investment if one is a developer of transmission and to provide more certainty to load serving entities as they weigh their purchase power options. We at PJM are committed to developing such a product and look forward to working with this Commission on the details of that product.

Challenge #3: Pricing Reform

To date, the Commission has sought to incentivize transmission investment by offering higher rates of return under the traditional cost of service model. Though the industry has generally supported this approach, it has not solved the problem of insufficient transmission investment. Perhaps it is time to move away from this incremental approach and take a new fresh look at how we price transmission. There are a range of options we can consider here. A number of countries have adopted performance based approaches where transmission owners can realize the gains associated with various improvements such as the reduction of losses or reduction in congestion. These approaches have considerable merit and can allow management to focus on meeting clearly defined public policy goals.

We can also consider going a step further and actually move away from cost based pricing altogether. We often argue that transmission solutions compete with generation and demand side solutions. However, at the end of the day we apply vastly different pricing regimes to these competing solutions which inevitably skew that competition. Perhaps in areas where there are truly substitutable resources, we should utilize a form of value of service pricing----allowing transmission to be priced at its value when compared against substitutable demand side or generation solutions. A "value of service" approach would need appropriate checks and balances and probably best works for incremental investment arising from a transparent planning process. We would need to be assured that there is a true level competitive playing field to identify and cap the asset's value so as to avoid the charging of monopoly rents. Along these lines, our Reliability Pricing Model will allow transmission to bid in as a capacity resource effectively allowing it to compete against generation and demand side. Through an organized capacity process such as RPM with a long term forward-looking approach, one can feel confident that the "price" of transmission has been set competitively and is priced in a manner which recognizes its true value to its customers. In short, we cannot, on one hand, champion the need for transmission to compete with generation and demand side alternatives but then refuse to price it in a competitive manner when those situations arise.

Challenge #4 Developing Innovative Business Models for Transmission

The Commission has spent many hours trying to create the right regulatory model for Independent Transmission Companies (ITCs). However, at the end of the day it is *not* regulatory action but a viable business model that will ensure the development of ITCs. To date, that business model has *somewhat* eluded us, partially because of the vertically integrated structure of our utilities, partially because of the mix of federal and state regulation, each which their own unique definitions of the service obligation, and partially because of the financial circumstances the industry has faced in recent times.

A few years ago, this Commission engaged in an extensive separation of functions (known as the "slicing and dicing" order). Unfortunately, we may have placed the cart before the horse. It is time to develop the viable business model and then, just as form follows function, adapt our industry structures to accommodate that business model. The potential repeal of PUHCA as well as the tax advantages passed by Congress provide some of the tools that could drive a change to industry structure.

Now is the time to reexamine the business model. While reexamination should build on the lessons learned from the TRANSLink proposal, the ITC and ATC experience in the Midwest and other attempts to form the business case for a stand alone transmission company, we should not stop at the experience of the electric industry. If our goals are as they should be, ensuring that we are building a strong regional grid and optimizing transmission investment, we should be prepared to look at alternative business models that will allow us to achieve that benefit without compelling divestiture of existing investment and/or consolidation of new transmission *investment* into a single entity.

For example, other industries, such as the aerospace industry, have successfully used consortiums to develop complex projects that have involved multiple governmental and industry players. The technology industry has also recognized that partnering rather than competing on investment is often the soundest path to success.

Presently, PJM is exploring a consortium-like model with our transmission owners to address issues associated with aging infrastructure by use of a different paradigm. We are approaching a replacement plan for aging transformers as if they were owned and operated by a single company. We are looking to apply a single set of criteria for determining which transformers need to be replaced across the whole market rather than continuing to have each transmission owner address the issue only as to their system. By applying this approach, we can prioritize transformer replacement based on their overall system impacts rather than simply by its impact within a single zone. In addition, we are looking at adopting a standard design for replacement transformers across the whole PJM market. Standardized transformers should result in cost savings due to combined buying power and economies of scale and provide for more interchangeability in the event of system

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failures. We are pursuing this consortium approach to achieve the benefits of common transmission ownership and operation without having to require current owners to divest or otherwise restructure their current asset ownership. We view this step as creating a "virtual ITC" for infrastructure issues while still respecting individual asset ownership.

This same approach can be considered for new transmission infrastructure. Asset management can take place under a single business model while still respecting individual ownership interests and providing opportunities for new investors into the grid. Under this approach, owners could standardize transmission line components and eventually achieve a level of interchangeability of supplies in the event of failures or catastrophic events. Applying this process proactively will result in components being replaced before they fail, harnessing the economies of regional scale and eliminating internal "seams" associated with asset management. We believe that our aging infrastructure initiative could provide a sound starting point for further development of this concept.

Challenge #5—Taking Advantage of Advanced Technologies

Despite valiant efforts by this Commission, the electric industry is still suffering from a lack of focus on how new technologies can enhance reliability and efficient grid operations. In addition to supplying the right incentives for new investment, we must also ensure ourselves that we are providing incentives for the right type of investment. Elsewhere in the world, companies are increasingly using advanced technologies to place better information from the field into the hands of the system operator. For example, the installation of automated substations can help reduce costs, increase reliability and system security. However, today North American investment in automated substations lags far behind the rest of the world. In addition to the investment recovery concerns addressed previously, the fractionalized ownership of the grid may be contributing to this failure since the cost/benefit analysis of these new technologies are much easier if once considers regional as opposed to local benefits.

Within the RTO, we have an opportunity to use advanced technologies to help ensure optimal operation of the grid at the lowest investment cost to the consumer. The challenge and opportunity before us is to expand on the work we are doing with aging infrastructure and fair pricing for new investment to help encourage and ensure that we are maximizing the value of advanced control and other system technologies.

In closing, as with all industries, 21st century technologies and business acumen afford us the opportunity to rethink and retool how we will evolve the grid. We have an unparalled opportunity to use price transparency, technology, information and, a new openness to rethink business, to optimize system investment and operation. I have shared with you some of our experiences and outlined our challenges going forward. We reiterate our pledge to work with everyone in this

room and in the industry to move beyond the rhetoric of the past and truly tackle these difficult issues of ensuring a 21st century approach to constructing the transmission grid of the future.

executive vice president

Audrey Zibelman, executive vice president of PJM Interconnection, oversees operations, planning, markets and internal supporting functions.

Ms. Zibelman came to PJM from TRANSLink, LLC where she was chief executive officer. TRANSLink was an independent transmission company organized to have operational control of transmission assets of 13 public and investor-owned utilities operating in 14 states.

Previous to TRANSLink, Zibelman held senior management positions at Xcel Energy Corporation. She began at Xcel as a senior attorney and then was named president of NSP Energy Marketing and Fuel Resources. She was vice president of integration management and then vice president of transmission before moving to TRANSLink. Ms. Zibelman has held the post of general counsel to the New Hampshire Public Utilities Commission and special assistant attorney general in Minnesota.

She earned her law degree from Hamline University Law School. She earned her BA from Pennsylvania State University.

Ms. Zibelman was a volunteer teacher with the Peace Corps after graduating from college. She also has served as chair of the Minnesota Urban Coalition.

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 45.3 million people in all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid; administers a competitive wholesale electricity market, the world's largest; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. Visit PJM at www.pjm.com.

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Docket Number A-110172

Name of Document ECC Cross Exam Ex 12, Ex 13

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ECC Cross Exam Ex 16

MAR 2 5 2008 ATTACHMENT ECC-I-63-A

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NEWS RELEASE

FOR IMMEDIATE RELEASE

PJM AUTHORIZES CONSTRUCTION OF $1.3 BILLION IN TRANSMISSION UPGRADES

First 15-year plan directs evaluation of a potential $10 billion in proposed projects

(Valley Forge, Pa. – June 23, 2006) – The PJM Interconnection Board today approved its first 15-year regional electric transmission plan. The plan is designed to maintain the reliability of the PJM area transmission system, which serves 51 million people in 13 states and the District of Columbia.

As part of the plan, PJM authorized construction of $1.3 billion in electric transmission upgrades, including a 240-mile, 500-kilovolt transmission line from southwestern Pennsylvania to Virginia to be constructed by Allegheny Power and Dominion. The total plan upgrades will ensure continued grid reliability through 2011 and are estimated to reduce congestion costs by $200 million to $300 million annually.

To meet long-term needs through 2021, PJM directed additional studies and evaluation of 10 significant transmission line proposals totaling $10 billion of potential new investment, including the high-voltage transmission line projects proposed by American Electric Power, Allegheny Power and Pepco Holdings Inc. Those proposals build on the solutions identified in PJM's Mountaineer concept, unveiled in May 2005, for new transmission lines and potential corridors for transmission in the eastern half of the PJM region.

"The Board of Managers' approval of the Regional Transmission Expansion Plan (RTEP) will result in additional investments in backbone transmission over the 15-year period and could resolve more than $1 billion in annual congestion costs," noted Phillip G. Harris, PJM president and chief executive officer. Transmission owners for these projects will proceed with preliminary siting evaluations, initial environmental impact assessment work and potentially right-of-way acquisition. PJM will continue to evaluate the projects.

PJM's RTEP includes upgrades and new projects to maintain system reliability and to interconnect new electric generation. PJM has expanded its planning horizon from five years to 15 years, and the current plan is the first with the longer period. The plan considers the growth and changes in the broad, multi-state region. By not being limited to considering just one utility's service territory, the PJM planning process can determine the most effective and cost-efficient transmission solution no matter where it is located in the region.

- MORE -

Contact: Paula DuPont-Kidd, toll free at 866-PJM-NEWS (756-6397)

"Regional transmission planning works," said Audrey A. Zibelman, PJM's executive vice president and chief operating officer. "It's stimulating the necessary investments in the grid to maintain reliability and to improve economic efficiency. We're excited about our first 15-year regional transmission plan and believe it's a big step not only for PJM but for the entire industry. We especially appreciate the hard work and contributions of our members over the last six months."

PJM has authorized more than $4 billion of accumulated transmission investment since its planning process began six years ago, resulting in an additional 18,717 megawatts of new generation being interconnected, with 3,777 megawatts of generation now under construction. More than a half-billion dollars in transmission projects have been completed.

"Our regional planning process has evolved to address different needs in response to changing conditions," Zibelman said. "The process has grown from one that primarily addressed reliability-driven upgrades and generation interconnection to the new, long-term planning effort that can better address economic efficiency and major transmission additions."

PJM Interconnection ensures the reliability of the high-voltage electric power system serving 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. PJM coordinates and directs the operation of the region's transmission grid, which includes 6,038 substations and 56,070 miles of transmission lines; administers the world's largest competitive wholesale electricity market; and plans regional transmission expansion improvements to maintain grid reliability and relieve congestion. Visit PJM at www.pjm.com.

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PROPRIETARY INFORMATION

Docket Number A-110172

Name of Document ECC Cross Exam Ex 17, 18, 19, 20 and 21 Maps

Date Document Received 3-25-2008

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ECC Cross Exam Ex 22

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TrAILCo Response to
ECC Interrogatory Set VIII, No. 1
Sponsor: Steven Herling
Response Date: January 7, 2008

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY
PaPUC Docket No. A-110172 et al.

ENERGY CONSERVATION COUNCIL OF PENNSYLVANIA Set VIII, No. 1:

ECC-VIII-1. Ref. Herling 3-R: p. 8, l. 1-6: Please describe all the basis [*sic*] for your conclusion that the "2007 RTEP analysis has shown the reliability criteria violations to be more severe than originally identified in the 2006 RTEP." Please identify the following *for each alleged reliability criteria violation:* (1) describe the electrical occurrence(s) and the alleged electrical result from each electrical occurrence; (2) the date when each alleged electric reliability problem is expected to arise; (3) the alleged standard used to determine that there was an alleged electric reliability problem (i.e., NERC category C3, PJM's load or generation deliverability standards, etc.); and (4) the study or studies that reached each conclusion that there was an alleged reliability problem.

RESPONSE:

The conclusion that the 2007 RTEP analysis has shown the reliability criteria violations to be more severe than originally identified in the 2006 RTEP is based on the results of the analyses performed in the two RTEPs, the increased number of criteria violations identified in the 2007 RTEP analysis, and the increased magnitude of the overloads observed associated with those criteria violations. The information requested in subpart (1) is provided in Attachment ECC-VIII-1-A. The information requested by subparts (2), (3) and (4) is found in the PJM Board of Managers presentation material for the Board Reliability Committee, which is contained in Attachment ECC-VIII-1-B and is CONFIDENTIAL, and in the PJM Transmission Expansion Advisory Committee meeting presentation material which is accessible via the following URLs:

- http://www.pjm.com/committees/teac/teac-archive.html
- http://www.pjm.com/committees/teac/downloads/20070509-reliability-analysis-update.pdf
- http://www.pjm.com/committees/teac/downloads/20070416-item-10-2007-rtep-reliability-analysis-update.pdf
- http://www.pjm.com/committees/teac/downloads/20061030-teac-presentation.PPT

- http://www.pjm.com/committees/teac/downloads/20060830-teac-presentation.pdf
- http://www.pjm.com/committees/teac/downloads/20060711-teac-presentation.PPT
- http://www.pjm.com/committees/teac/downloads/20060523-teac-presentation.pdf
- http://www.pjm.com/committees/teac/downloads/20060301-presentation.pdf

Also see responses to ECC-I-34(b); ECC-I-35, Attachment ECC-I-35- F; ECC-II-53

ECC Cross Exam Ex 23
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Attachment ECC-VIII-1-A

2007 RTEP - Amos – Kemptown Line
Electric Reliability Problems

	Electrical Occurrence	Electrical Result	Year of Violation
1	Outage of Keystone - Conemaugh 500kV Line.	Keystone - Airydale 500kV Line exceeds its emergency rating and overloads.	2012
2	Outage of Juniata - Keystone 500kV Line.	Keystone - Conemaugh 500kV Line exceeds its emergency rating and overloads.	2012
3	Outage of Hatfield - Black Oak 500kV Line + Black Oak 500/138kV transformer.	Mt. Storm - Doubs 500kV Line exceeds its emergency rating and overloads.	2012
4	Outage of Juniata - Keystone 500kV Line.	Airydale - Juniata 500kV Line #1 exceeds its emergency rating and overloads.	2013
5	Outage of Conemaugh - Juniata 500kV Line.	Airydale - Juniata 500kV Line #2 exceeds its emergency rating and overloads.	2013
6	Outage of Mt Storm - 502 Junction 500kV Line.	Pruntytown - Mt. Storm 500kV Line exceeds its emergency rating and overloads.	2015
7	Outage of Bath County - Valley 500kV Line.	Lexington - Dooms 500kV Line exceeds its emergency rating and overloads.	2017
8	Outage of Mt Storm - Doubs 500kV Line.	Loudon - Pleasant View 500kV Line exceeds its emergency rating and overloads.	2017
9	Outage of Mt Storm - Meadowbrook 500kV Line.	Greenland Gap - Meadowbrook 500kV Line exceeds its emergency rating and overloads.	2020

	Electrical Occurrence	Electrical Result	Year of Violation
10	Outage of Mt Storm - Meadowbrook 500kV Line.	Mt. Storm - Greenland Gap 500kV Line exceeds its emergency rating and overloads.	2020
11	Outage of Alburtis - Branchburg 500kV Line.	Hosensack - Elroy 500kV Line exceeds its emergency rating and overloads.	2021
12	Outage of Dooms - Lexington 500kV Line.	Bath County - Valley 500kV Line exceeds its emergency rating and overloads.	2022

Note : Most severe violation, in all cases, is based on Load Deliverability criteria. All electrical results other than 8 and 12 have secondary violations related to other Load Deliverability and/or Generator Deliverability electrical occurrences.

ECC Cross Exam Ex 24
MAR 25 2008 Pgh JK A-110172

TrAILCo Response to
ECC Interrogatory Set VIII, No. 9
Sponsors: Steven Herling, Lawrence Hozempa
Response Date: January 7, 2008

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY
PaPUC Docket No. A-110172 et al.

ENERGY CONSERVATION COUNCIL OF PENNSYLVANIA Set VIII, No. 9:

ECC-VIII-9. Were any studies done by PJM, TrAILCo, or any other entity in which the Amos—Kempton line was assumed to be in service, but the 502 Junction-Loundon [*sic*] line was assumed not to be in service? If so, please describe the studies, dates, and results of the studies, and produce the documents, data, and the reports from these studies.

RESPONSE:

During the preparation of the 2007 Regional Transmission Expansion Plan ("RTEP"), PJM identified a number of reliability criteria violations in the 2012 planning year, assuming that the 502 Junction – Loudoun line was placed in service in 2011. See response to ECC-VIII-1. In the course of evaluating the Amos – Kemptown line as a means to resolve those violations, PJM simulated the 2012 summer conditions with the Amos – Kemptown line placed in service and the 502 Junction – Loudoun line removed from service. Observing that the Amos – Kemptown line was not sufficient to resolve the identified criteria violations in the absence of the 502 Junction – Loudoun line, PJM retained the 502 Junction – Loudoun line in the RTEP. No separate documentation was developed for the simulations involving the removal from service of the 502 Junction – Loudoun line.

ECC Cross Exam Ex 25
MAR 25 2008 fgh Dk A-110172

TrAILCo Response to ECC Interrogatory Set II, No. 25
Sponsor: Lawrence A. Hozempa
Response Date: August 20, 2007

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY
PaPUC Docket No. A-110172 et al.

ENERGY CONSERVATION COUNCIL OF PENNSYLVANIA Set II, No. 25:

ECC-II-25. Referring to the load forecasting data included in Gass Exhibit SWG-2, why does the "Northern Virginia-APS Summer peak decline by 10.4% in 2008?

RESPONSE:

Reduction in projected summer peak load from 2007 to 2008 is based on an anticipated reduction in demand resulting from the removal of rate caps in Virginia in 2008.

ECC Gass Exam Ex 26
MAR 2 5 2008 Pg 1 of A-110172

TrAILCo Response to
ECC Interrogatory Set VII, No. 26
Sponsor: Scott Gass
Response Date: December 27, 2007

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY
PaPUC Docket No. A-110172 et al.

ENERGY CONSERVATION COUNCIL OF PENNSYLVANIA Set VII, No. 26:

ECC-VII-26. Ref. Hozempa 2-R: p.25, l. 17-19. Mr. Hozempa testifies that the load flow model used to determine the need for the PATH project had the TrAIL modeled in it. Was the proposed PATH line in the load flow model used to determine the alleged need for the TrAIL project? If so, *please identify and produce all of this modeling, back-up data for same, and all documents* describing or summarizing this analysis or modeling.

RESPONSE:

The proposed PATH line was not in the load flow model used to determine the need for the TrAIL project.

ECC Cross Exam Ex 27
MAR 2 5 2008 Pgh PK A-110172

TrAILCo Exhibit SWG-2

Projected Summer Peak Loads (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Cumulative
Mid-Atlantic Region	58742	59611	60965	61966	62850	63777	64648	65798	66845	67725	
% Growth		1.5%	2.3%	1.6%	1.4%	1.5%	1.4%	1.8%	1.6%	1.3%	15.3%
Northern Virginia - Dominion	5936	6037	6205	6316	6411	6532	6656	6780	6911	7035	
% Growth		1.7%	2.8%	1.8%	1.5%	1.9%	1.9%	1.9%	1.9%	1.8%	18.5%
Northern Virginia - APS	711	721	646	661	678	693	710	728	748	768	
% Growth		1.4%	-10.4%	2.3%	2.6%	2.2%	2.5%	2.5%	2.7%	2.7%	8.0%

ECC Cross Exam Ex 28
MAR 2 5 2008 Pgh JK A-110172

TrAILCo Exhibit SWG-2

Projected Summer Peak Loads (MW)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Cumulative
Mid-Atlantic Region	58742	59611	60965	61966	62850	63777	64648	65798	66845	67725	
% Growth		1.5%	2.3%	1.6%	1.4%	1.5%	1.4%	1.8%	1.6%	1.3%	15.3%
Northern Virginia - Dominion	5936	6037	6205	6316	6411	6532	6656	6780	6911	7035	
% Growth		1.7%	2.8%	1.8%	1.5%	1.9%	1.9%	1.9%	1.9%	1.8%	18.5%
Northern Virginia - APS	611	630	646	661	678	693	710	728	748	768	
% Growth		3.1%	2.5%	2.3%	2.6%	2.2%	2.5%	2.5%	2.7%	2.7%	25.7%

TrAILCo Response to OCA Interrogatory Set I, No. 32
Sponsor: Scott W. Gass
Response Date: July 16, 2007

IN RE: APPLICATION OF TRANS-ALLEGHENY INTERSTATE LINE COMPANY
PaPUC Docket No. A-110172 et al.

OFFICE OF CONSUMER ADVOCATE Set I, No. 32:

OCA-I-32. Please refer to TrAILCo Exhibit SWG-1.

a. Please list the year in which each of the electrical occurrences listed in Chart A first produces the electrical result listed in Chart A.

b. Please provide the generator operating assumptions, power import assumptions and power export assumptions for PJM that were used in the studies that are reflected in Chart A.

c. Please provide the generator operating assumptions, power import assumptions and power export assumptions for the Allegheny Power zone that were used in the studies that are reflected in Chart A.

d. For each of the electrical results listed in Chart A where line ratings are being exceeded, please provide the rating level that is being exceeded and the amount by which such ratings are being exceeded.

e. For each of the electrical results listed in Chart A where voltage levels drop below acceptable limits, please provide the voltage level limit that is required and the voltage level that results from the electrical occurrences listed for each substation bus at which voltage drops below acceptable limits.

RESPONSE:

a. See direct testimony of Scott W. Gass (TrAILCo Statement No. 4) at page 8, lines 12-15.

b. The import and export assumptions for the 2011 RTEP are contained on page 8 of the 2006 Baseline RTEP Report which is located at http://www.pjm.com/planning/rtep-baseline-reports/downloads/2006-baseline-report.pdf. These import and export values were used for all studies reflected in Chart A except for the Load Deliverability studies. For the Load Deliverability studies (which simulate a capacity emergency situation), additional imports of 2900 MW were modeled from New York to PJM.

It is assumed that the term "generator operating assumptions" refers to the generator dispatch pattern applied for the various studies. The PSS/e cases provided in response to OCA-I-27, OCA-I-30 and OCA-I-31 contain the generator dispatch patterns.

c. There were no generator operating assumptions, power import assumptions or power export assumptions specific to the Allegheny Power transmission zone that were different than the assumptions referred to in response to part b. above.

d. See Attachment OCA-I-32-A, which provides the rating level and the percent overload for each electrical result in Chart A.

e. The voltage limit for 500 kV substations is 0.97 PU and for 230 kV and 138 kV the voltage limit is 0.92 PU. See Attachment OCA-I-32-B which provides the results for the situations where voltage levels drop below acceptable limits. Attachment OCA-I-32-B is confidential and will be provided in accordance with the terms and conditions of any protective order issued in this proceeding.

Reliability Problem #	Electrical Occurance	Electrical Result	Planning Criteria Violated	Year Of Violation	Rating	% Overload
1	Outage of Mount Storm – Greenland Gap Line #572A (Operating procedure also opens North Shenandoah 138/115 kV and Strasburg - Edinburg 138 kV)	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / PJM Load Deliverability Procedure	2011	2598 MVA	106%
1	Outage of Mount Storm – Greenland Gap Line #572A (Operating procedure also opens North Shenandoah 138/115 kV and Strasburg - Edinburg 138 kV)	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / PJM Generator Deliverability Procedure	2011	2598 MVA	101%
2	Outage of Meadowbrook – Greenland Gap Line #572B (Operating procedure also opens North Shenandoah 138/115 kV and Strasburg - Edinburg 138 kV)	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / PJM Load Deliverability Procedure	2011	2598 MVA	106%
2	Outage of Meadowbrook – Greenland Gap Line #572B (Operating procedure also opens North Shenandoah 138/115 kV and Strasburg - Edinburg 138 kV)	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / PJM Generator Deliverability Procedure	2011	2598 MVA	101%
3	Outage of Hatfield – Black Oak 500 kV Line #542 (Operating procedure also opens Black Oak 500/138 kV transformer)	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / PJM Load Deliverability Procedure	2011	2598 MVA	104%
3	Outage of Hatfield – Black Oak 500 kV Line #542 (Operating procedure also opens Black Oak 500/138 kV transformer)	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / PJM Generator Deliverability Procedure	2011	2598 MVA	100%
4	Outage of Bedington - Black Oak 500 kV	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / PJM Load Deliverability Procedure	2011	2598 MVA	104%
5	Outage of Mount Storm – Greenland Gap 500 kV Line # 572A (Operating procedure also opens North Shenandoah 138/115 kV and Strasburg - Edinburg 138 kV) while Possum Point Unit #5 is unavailable.	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / Dominion Planning Criteria	2011	2598 MVA	102%
6	Outage of Meadowbrook – Greenland Gap 500 kV Line # 572A (Operating procedure also opens North Shenandoah 138/115 kV and Strasburg - Edinburg 138 kV) while Possum Point Unit #5 is unavailable.	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / Dominion Planning Criteria	2011	2598 MVA	102%
7	Outage of Hatfield – Black Oak 500 kV Line # 542 (Operating procedure also opens Black Oak 500/138 kV transformer) while Possum Point Unit #5 is unavailable	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / Dominion Planning Criteria	2011	2598 MVA	100%
8	Outage of Bedington – Black Oak 500 kV Line # 544 while Possum Point Unit #5 is unavailable	Mount Storm – Doubs 500 kV Line #512 exceeds its emergency rating and overloads	NERC TPL-002-0 / Dominion Planning Criteria	2011	2598 MVA	100%
9	Outage of Hatfield – Black Oak 500 kV Line # 542	Mount Storm – Pruntytown 500 kV Line #510 exceeds its emergency rating and overloads	NERC TPL-002-0 / PJM Generator Deliverability Procedure	2014	3502 MVA	100%