REBUTTAL TESTIMONY
OF
STEVEN R. HERLING
ON BEHALF OF
VIRGINIA ELECTRIC AND POWER COMPANY
BEFORE THE
STATE CORPORATION COMMISSION
CASE NO. PUE-2007-00031

Q. Please state your name and business address.

A. My name is Steven R. Herling and my business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403-2497.

Q. Have you previously filed testimony in this proceeding?

A. Yes. I have filed written direct testimony on behalf of Dominion Virginia Power ("DVP").

Q. Please describe the purpose of your rebuttal testimony.

A. This rebuttal testimony addresses various assertions concerning PJM Interconnection, L.L.C. ("PJM") and the regional transmission planning process, presented in the direct testimony of Virginia's Commitment witness Ren Orans, Piedmont Environmental Council witness Hyde Merrill, CPV Warren witnesses Sharon K. Segner and James D. Bouford, and Commission Staff witnesses Cody Walker and Nicholas Puga and Songhoon Yang of Bates White, LLC ("Bates White").

Q. Will you be using the same terms in your rebuttal testimony as set forth in the table of nomenclature attached to the application?

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

Q. What is the purpose of this rebuttal testimony?

A. Broadly stated, I would like to explain that PJM is a Federally-approved Regional Transmission Organization ("RTO"), and as such PJM is responsible to ensure the reliability of the transmission grid in the PJM territory. PJM applies the criteria of the North American Electric Reliability Corporation ("NERC") to evaluate the reliability of the transmission system and then determines the transmission upgrades that are needed to ensure NERC reliability standards are met. Although PJM is authorized by the Federal Energy Regulatory Commission ("FERC") to direct the building of new transmission projects for grid reliability, it does not operate in a vacuum. The PJM planning process is open and dynamic, and all decisions and analysis are subject to stakeholder review and participation. The entire process is on file with FERC and detailed in the PJM Operating Agreement.

As I will discuss in more detail in this testimony, the need for the 502 Junction – Mt. Storm – Meadow Brook – Loudoun 500 kV circuit ("502 Junction – Loudoun Line" or the "Project") was determined through this process. PJM's evaluation of the transmission system and the need for the planned 502 Junction – Loudoun Line was accomplished in an open and transparent forum. Sound planning principles were applied and PJM provided every opportunity to consider alternative solutions for the Project. No alternative solution or combination thereof, including Demand Resource ("DR") programs, additional generation, and alternative technologies, has been identified to obviate the need for this line, either during the PJM planning process or, as I will discuss below, during this proceeding. Bates White concludes that DR programs or new generation is not a feasible alternative to the 502 Junction – Loudoun Line, in terms of reliably meeting the expected 2011 demand (Bates White, p. 97 ¶ 280). Further, the need for the Project is significant and urgent. PJM forecasts reliability violations as early as 2011 if the Project is not completed on schedule. My rebuttal testimony is organized in several sections:

- In Section I, I show that the need for the 502 Junction – Loudoun Line is grounded in specific transmission system reliability violations that PJM, in its role as an RTO was obligated to investigate and identify. Further, PJM is in agreement with the findings of Bates White regarding the definitive need for the 502 Junction – Loudoun Line.
- In Section II, I show that the reliability criteria applied by PJM are just and reasonable and conform to the industry standards.
- In Section III, I show that PJM considers alternatives to projects and adapts to known changes that occur within the PJM region, such as new transmission solutions and market forces.
- In Section IV, I show that PJM thoroughly considered new generation as an alternative to the 502 Junction – Loudoun Line and determined that this is not a feasible alternative.
- In Section V, I demonstrate that market-based solutions were considered by PJM and determined not to be feasible alternatives to the 502 Junction – Loudoun Line.
- In Section VI, I show that the interveners' concerns that the 502 Junction – Loudoun Line will cause adverse economic impacts are unwarranted.

Q. Why is PJM's role so specifically defined, and why is PJM empowered only to plan and direct transmission solutions?

A. Consistent with its FERC approved tariffs, PJM, as an RTO, was delegated reliability planning responsibilities for the transmission system within PJM, as well as the responsibility for the reliable interconnection of generation resources. Initially, FERC's issuance in 1996 of Order No. 888 established the *pro forma* tariff as the basis for a common set of rules for newly restructured utilities. This Order set forth the general principles of organization and operation for Independent System Operators ("ISOs") as control area operators. This was among the first steps toward the restructuring of the interstate electric transmission and wholesale power industry. FERC recognized that larger regional organizations could operate more efficiently and economically.

In Order No. 888, FERC initially determined that an ISO must have primary responsibility for the short-term reliability of grid operations, including planning and oversight of maintenance of transmission facilities under its control. The concept developed further, and FERC's Final Rule on RTOs, Order No. 2000, was issued in December 1999, representing the next step in the evolution of PJM's planning processes. Order No. 2000 created the RTO concept and established the rules and functions for them. Order No. 2000 also required public utilities to make appropriate filings with FERC to initiate the process to place their transmission facilities under the control of RTOs. FERC believed there would be widespread competitive advantages resulting from RTOs, including more efficient and effective transmission and generation planning. Order No. 2000 listed seven minimum functions that an RTO must perform. One function is to plan and coordinate necessary transmission additions and upgrades. Also, Order No. 2000 required the RTO to perform its functions consistent with the reliability standards established by NERC or its successor.

PJM and its transmission owners made a joint compliance filing for Order No. 2000 in October 2000, and FERC granted PJM provisional RTO status in July 2001. This initial filing included the PJM Regional Transmission Expansion Plan ("RTEP"), which was subsequently modified pursuant to FERC's Order No. 2001. The PJM Operating Agreement, which includes the PJM RTEP process, provides that expansion plans will emerge from a coordinated process involving the transmission owners for the region, and that these plans will be reviewed publicly through the PJM Transmission Expansion Advisory Committee ("TEAC"). Also, PJM's manuals, long-term planning, and RTEP process must all conform to NERC standards.

Finally, FERC has vested in PJM the ultimate responsibility for transmission expansion planning in the PJM control area. In order to carry out this responsibility, FERC authorized PJM to direct the construction of new transmission in order to ensure system reliability, consistent with the terms of its agreements with its transmission owners. PJM's planning and expansion process was also specifically designed to encourage market-driven operating and investment actions for preventing and relieving congestion. Hence, PJM's authority today is limited to requiring new transmission facilities in accordance with NERC standards, in order to allow for the continuation of open and competitive markets.

In 2006, PJM transitioned to a longer term RTEP process that develops a 15-year plan to ensure adequate time for siting, permitting, design and construction of larger high voltage projects. This process provides for major high voltage transmission upgrades within PJM and also provides long-term signals to the marketplace to facilitate the development of new generation. In addition, a new capacity construct called the Reliability Pricing Model ("RPM") was also implemented in 2007.

I. BATES WHITE AND THE RELIABILITY NEED FOR THE PROJECT

Q. Bates White (p. 3, ¶ 7) notes that PJM's planning process is conducted from a regional perspective and requires "that Virginia's PJM member electric utilities productively participate in establishing and supporting the regional objectives of PJM in accordance with policy decisions of FERC. . . [t]he consideration of proposed transmission infrastructure within Virginia may substantially involve regional loads and/or facilities remote to the Commonwealth." Please explain the regional aspect of the PJM planning process and the impact the Project is expected to have on the Commonwealth.

A. PJM does not perform planning based on the service territories of its transmission owners. Rather, PJM ignores the boundaries between transmission owners when evaluating the reliability of the grid and when developing solutions to reliability criteria violations. In all cases, the relevant "service territory" with respect to a violation of NERC criteria is the entire PJM system. This is implicit in the concept of deliverability, which drives much of the PJM planning process. PJM utilizes load and generation deliverability tests designed to ensure that the aggregate of PJM generation can be delivered to the aggregate of PJM customer load under a range of prescribed conditions. Through this process, PJM identifies specific transmission solutions for criteria violations, based on the documented procedures related to the evaluation of those criteria, not with respect to the service territories of individual transmission owners.

Q. Bates White (p. 3, ¶ 8) states that the revised 2007 PJM load forecast projects higher expected load for both DVP and Allegheny transmission zones and therefore "the need for the proposed Loudoun Line [is] even more critical than the results shown in the 2006 RTEP." Please explain how the 2007 PJM load forecast shows the need for the Project is more critical than in the 2006 RTEP.

A. The RTEP process is very dynamic. System conditions and, therefore, study assumptions are continually changing. After the 502 Junction – Loudoun Line was approved in June 2006, changed conditions were studied in the 2007 RTEP analysis. These changes included updated load forecasts and load models, the execution of a service agreement for a previously queued long-term firm transmission service, and revised modeling parameters for the 502 Junction – Loudoun Line, among other things. The 2007 RTEP analysis showed that the reliability criteria violations identified in the 2006 RTEP had become ***more severe*** in the 2007 RTEP. In fact, the scope of the violations identified in the 2007 RTEP indicates that both the 502 Junction – Loudoun Line and an additional Amos – Kemptown 500 kV Line (sometimes identified as "PATH") will now be required to address NERC criteria violations.

Q. Bates White (p. 3, ¶ 9) notes, "It would be highly risky to rely on market forces to resolve reliability issues." How does PJM resolve reliability issues?

A. PJM resolves reliability issues through a planning process integrated with a range of opportunities for the development of market-based solutions. The planning process evaluates the PJM grid for compliance with reliability criteria, taking into consideration the needs of transmission service customers and the impacts of potential market-driven generation, demand response, and merchant transmission proposals. However, only a finite window of time is available to resolve future specific criteria violations. The planning process identifies and requires transmission solutions to resolve reliability criteria violations that are not met with reasonable certainty by solutions provided through the market, allowing such transmission solutions to be re-evaluated if additional market solutions become certain in a timely manner.

Q. Bates White (p. 37, ¶ 103) concludes "Therefore, both the BW and DVP contingency analyses show that there is a need to improve the existing grid in order to reliably meet expected load in 2011." Do you agree with these findings and what does PJM's RTEP show?

A. The results of PJM's 2006 RTEP analysis clearly support the analyses performed by both Bates White and DVP. As discussed in the direct testimony of Mr. Gass, PJM identified a number of violations of reliability criteria that drive the need for the 502 Junction – Loudoun Line in 2011. What is most telling is that these three bodies of analysis arrive at the same conclusion through assessments across a range of critical system conditions and modeling assumptions.

Q. Do you agree with the conclusions in Bates White (p. 47, ¶ 129) that ". . . the proposed Loudoun line, is an adequate solution to resolve the expected reliability violations that may occur as early as 2011"?

A. Yes, PJM's RTEP analyses confirm that the 502 Junction – Loudoun Line resolves the reliability criteria violations identified to occur in 2011.

Q. Mr. Orans states that the RTEP process is not adequate to justify the need for the Project and not sufficiently transparent, regarding assumptions and data used in the RTEP. Mr. Orans (p. 30) asserts that the lack of transparency means ". . . the SCC is essentially left in the position of having to trust the Applicants' word on the need for the line." Can you address these concerns?

A. First, as I explain in my direct testimony, the RTEP process as codified in Schedule 6 of the PJM Operating Agreement is open, transparent and collaborative from start to finish. Forums and processes provide opportunities for stakeholders to help PJM improve the transmission grid, ensuring reliability and access to robust, competitive markets. The RTEP process allows opportunity for direct participation and exchange of information through two primary committees – the TEAC and the Planning Committee. These Committees meet regularly and are open to all PJM stakeholders. The primary function of the TEAC is to provide advice and recommendations to aid in the development of the RTEP. The primary purpose of the Planning Committee is to provide data, information and support necessary for PJM to perform studies as required and to develop the RTEP and, as part of the broader PJM committee structure, to support the development of changes to the planning process, which may include amendments to the PJM Agreements and revisions to the PJM Manuals.

As stated in Schedule 6, Sec. 1.3(b) of the PJM Operating Agreement, PJM Transmission Customers (as that term is defined in the PJM Tariff), and applicants for transmission service; any other entity proposing to provide Transmission Facilities to be integrated into the PJM Region, all PJM members; the agencies and offices of consumer advocates of the States in the PJM Region exercising regulatory authority over the rates, terms or conditions of electric service or the planning, siting, construction or operation of electric facilities and any other interested entities or persons, can participate in the development of the RTEP through the TEAC. The existence and role of the TEAC is also described in the PJM Operating Agreement. Through the TEAC, PJM invites written comments and opinions from its stakeholders, regarding the RTEP and RTEP process. These comments are shared with the PJM Board of Managers as well as posted on the PJM website. This exchange of information is designed to support the open and cooperative forum for PJM's planning processes. Notably, PJM represents a diverse group of stakeholders with diverse financial interests and as such these stakeholders also represent a wide range of opinions on how planning should be conducted and how planning decisions ultimately should be made. As in any open forum, all the input of the participants and stakeholders is afforded review and consideration.

PJM manages a dynamic and diverse planning process. The PJM RTEP process is designed to efficiently and effectively plan the transmission grid for reliability and to meet all transmission service needs for a reliable and economical system. In the course of this process, PJM shares information regarding the data and input used in the analyses as well as the processes relied upon in the course of the analyses. PJM's planning processes and methodologies are discussed in more detail in the PJM Manuals as well as in the PJM Operating Agreement.

II. PJM'S RELIABILITY CRITERIA

Q. Dr. Merrill (p. 28) states that PJM statements that NERC, PJM, and DVP planning criteria have been accepted by FERC are erroneous. Is he correct?

A. Absolutely not. PJM has clearly stated FERC has approved the NERC planning standards and the PJM planning process. In addition, PJM's planning criteria is utilized to implement assessment of compliance with NERC standards, although PJM does not specifically file the planning criteria with FERC, and FERC does not approve the PJM or DVP planning criteria.

PJM's identification of transmission system reliability issues is a federally-approved mandate, performed in accordance with the FERC-approved requirements as presented in the PJM Agreements. PJM's 2006 RTEP conclusively demonstrates the need for transmission upgrades to address the identified reliability violations. Further, these reliability violations were determined in accordance with NERC reliability criteria and testing. First, PJM is obligated to apply NERC reliability criteria in its planning process.

The FERC established this requirement in 1999 in its Order No. 2000. The U.S. Energy Policy Act of 2005 ("EPAct") called for the creation of an international "electricity reliability organization" and further strengthened NERC. In compliance with EPAct requirements, FERC certified NERC as the "electric reliability organization" for the U.S. in July 2006, and on June 18, 2007, compliance with NERC Reliability Standards became a legal requirement for bulk power system owners, operators and users.

The NERC criteria specify a wide range of reliability tests that must be applied over both the short and long-term planning horizon. Due to the nature of any planning process, PJM is required to make a number of assumptions in order to perform the analyses required to demonstrate compliance with these NERC criteria.

Pursuant to the PJM Operating Agreement, PJM documents all these assumptions, which are then thoroughly reviewed with stakeholders in the course of each cycle of the planning process. For example, PJM must apply initial assumptions regarding load forecasts, the development or retirement of generation and demand response resources, and electricity transfer levels between portions of the grid. Forecasting future events requires PJM to make assumptions about those events, but the need to make assumptions does not impair the validity of the planning process or the results it produces, as some witnesses have suggested. Stated differently, if one were to eliminate all forecasting of load growth and new generation or retirements from the transmission reliability processes, then planning for transmission system adequacy would be impossible. It is our experience that the use of projections in electric system planning is an integral, well-accepted and necessary practice for both electric utilities and the agencies that regulate them. If PJM identifies NERC criteria violations at the conclusion of the RTEP process, the NERC standards require that solutions be developed and implemented to mitigate those violations. This was the outcome of PJM's 2006 RTEP process, and is the fundamental reason for PJM's direction to Allegheny Power and DVP to undertake the transmission system reinforcements that constitute the Project. In other words, the DVP and TrAILCo applications are the result of PJM's Federally-mandated efforts as an RTO to identify and attempt to resolve transmission reliability issues within its control area.

Q. Mr. Orans (p. 14) contends that the contingency used to demonstrate the need for the Project is "extremely unlikely." Please explain the analysis that is completed to demonstrate the need for the proposed line.

A. The contingencies used to demonstrate the need for the 502 Junction – Loudoun Line are all consistent with the application of NERC criteria. What Mr. Orans and others ignore is the requirement within the NERC standards to identify the critical system conditions under which the standards are to be tested. PJM's critical system conditions associated with NERC reliability contingencies are defined through the generation and load deliverability tests. While the planning standards evaluate the loss of one or two system elements, typical operating conditions on the PJM system involve dozens of generating and transmission facilities out of service. It seems obvious that the planning standards and critical system condition used for this purpose should impose a rigorous test resulting in a transmission system robust enough to stand up to the many unrelated generation and transmission element outages that occur on a day-to-day basis.

Q. What is your response to the assertion by Dr. Merrill (p. 27) that PJM's load deliverability and generation deliverability tests are not industry standard?

A. PJM's load and generation deliverability testing methods are an established means for addressing system deliverability and certainly conform to industry standards. The concept of deliverability is twofold. The load deliverability test is designed to assure that a pocket of load experiencing a resource capacity shortage can rely on the capability of the transmission system to deliver energy from resources available from the aggregate generation within the remainder of the PJM system as well as from resources available outside of the PJM system. Generation deliverability ensures that clusters of capacity resources within PJM have sufficient transmission capability to be delivered to the aggregate of PJM load during circumstances where the capacity of that cluster of resources is needed due to higher than normal unavailability of resources elsewhere in PJM. In other words, the generation deliverability test ensures that deliverable capacity resources are not bottled up when needed. Both tests evaluate the ability of the transmission system to deliver energy from the aggregate of generation in one area to the aggregate of load in another.

Further, the load deliverability criteria are designed to provide a needed linkage between the resource adequacy planning process and the transmission planning process. Load deliverability analyses over the 15-year planning horizon send signals to the market as to where generation and demand response resources will be required, in the future, to resolve developing reliability concerns. Load deliverability also serves as the basis for price separation in RPM auctions, which provide incentives for the development of generation and demand response resources in constrained areas of the system. By providing signals to the market over the 15-year planning horizon, developers can anticipate areas where capacity prices will be higher and their resources more valuable. The transmission planning process considers the impact of such projects when evaluating the ongoing compliance of the system with reliability criteria. To the extent that sufficient resources are developed to mitigate future reliability criteria violations, further transmission system upgrades become unnecessary. To the extent that the signals provided through the RTEP and RPM auctions are ignored, and reliability criteria violations develop in the future, then the RTEP process must identify the transmission system upgrades required for the system to remain compliant with those criteria.

Q. Dr. Merrill (p. 29) suggests that DVP applies a more restrictive criterion that the system withstands the loss of two generators or of a generator and a transmission line without loss of demand. Do you agree that the DVP criteria are more restrictive than NERC's criteria, and does PJM agree with these criteria?

A. NERC criteria require that the transmission system be tested under a critical system condition, defined by the transmission planner. Clearly, some number of generating units must be turned off in order to match load and transfers with generation. No one would think to suggest that each such generator represents a discrete contingency. Dr. Merrill suggests that the generation pattern should be based on an economic dispatch. The NERC criteria make no such requirement, and an economic dispatch may be far from the critical system condition required in the standards. DVP has defined its critical system condition to include the outage of Possum Point #5 as the most critical generating unit. This outage is a part of the base system condition upon which criteria testing is performed. Thus, the outage of Possum Point #5 is not a first contingency. DVP's criteria tests for the loss of each line or generator against its critical system condition. These are NERC Category B tests, not Category C tests as Dr. Merrill suggests.

Q. Dr. Merrill (p. 30) implies that rolling blackouts are acceptable for Virginia consumers. In particular an ". . . acceptable response includes controlled interruption of electric supply to customers (load shedding), planned removal from services of certain generators, and curtailment of firm (non-recallable reserved) electric power transfers . . . ." Does PJM agree with this standard?

A. PJM does not advocate the reliance on rolling blackouts as an acceptable condition for maintaining system reliability, and Virginia consumers should not expect to be subject to rolling blackouts as a means for congestion management. While the NERC standards allow for consequential loss of load following Category C events, they do not contemplate the need to shed customer load following a Category B event, as a preventative measure, in order to prepare for the possibility of a second contingency. Notably, as discussed below, the residents of Northern Virginia and eastern West Virginia would likely be directly impacted by a loss of load scenario related to the constraints driving the need for the 502 Junction – Loudoun Line.

Q. How does consequential load loss differ from rolling blackouts or operator-initiated load shedding?

A. Consequential load loss is the loss of a controlled amount of load as a function of the configuration of the system. Load served from a substation with only two source feeds will be lost if both feeds are tripped in the evaluation of NERC Category C3 events. Consequential load loss cannot be viewed as requiring emergency action by operators in order to prevent a cascading outage. As part of it emergency procedures, PJM operators will direct customer load to be shed to control a transmission emergency when no other available options remain. In such cases, the customers that have the greatest impact on the particular transmission constraint will be shed first. In the case of the Mt. Storm – Doubs Line, customers in northern Virginia, Washington, D.C., Baltimore, and the eastern West Virginia panhandle would have the most direct effect and would be shed first. However, such actions cannot be considered acceptable as consequential load loss within the context of the NERC standards. Further, as the magnitude of consequential load loss increases, prudent utility practice would suggest the need for further transmission system upgrades.

III. ALTERNATIVE SOLUTIONS, NEW DEVELOPMENTS AND THE CONTINUING NEED FOR THE PROJECT

Q. You have indicated that PJM does not have the power to direct "alternative" solutions, as several of the interveners have suggested. Please explain what PJM is authorized to do and not to do in this regard.

A. As an RTO, PJM has a very defined role in the deregulated electric industry. Its primary transmission-related responsibility is to ensure the reliability of the bulk power transmission system. Although PJM has a number of important tools at its disposal – including the ability to direct transmission owners to construct transmission system reinforcements – its powers are not plenary. PJM is ***not able*** to direct or otherwise control the siting, capacity, or timing of new generation in high-load areas. PJM is ***not able*** to direct or otherwise control the design and implementation of DR efforts that might, if properly placed and of sufficient dimension, delay or defer the need for transmission reinforcements. PJM can ***only*** direct the reinforcement of transmission facilities to address reliability violations, either through the modification of existing transmission facilities (which PJM quite frequently directs) or the construction of new transmission facilities.

Q. Are you suggesting that other alternatives are never feasible, or that PJM does not consider them in evaluating the need for transmission reinforcements?

A. Absolutely not. PJM's planning processes recognize that many of the generation- and DR-based alternatives mentioned by the interveners could, if they were targeted, verifiable, and implemented on time and in the right areas of the PJM Region, address identified system reliability issues. As I mentioned above, PJM has a very specifically defined role in this restructured industry. Because the consequences of reliability criteria violations can be severe, PJM's mandate first is to maintain system reliability. That being said, however, PJM's planning process is expressly designed to be responsive to solutions developed ***through the marketplace,*** as well as transmission solutions.

From my review of the RTEP and the filings by Dominion and TrAILCo, it is my view that the 502 Junction – Loudoun Line offers a reasonable long-term solution to anticipated reliability shortfalls that will occur in the near future absent such a solution. Having reviewed the testimony from parties opposing the Project, I have seen nothing that offers a comparable solution. It is perhaps easy to suggest short term, band-aid approaches to cure isolated pockets of degrading reliability circumstances, but such short term projects will not cure the long-term, systemic problems giving rise to the need for the transmission capability offered by the 502 Junction – Loudoun Line and would result in an ongoing need for additional such projects on a year to year basis. In my opinion the Project offers the best solution to the transmission reliability concerns that Allegheny Power and PJM will face in the near future. Further, I agree with the conclusions in Bates White (p. 47, ¶ 129) that the Project is an adequate solution to resolve the expected reliability violations that may occur as early as 2011.

Q. Throughout his testimony Dr. Merrill notes that circumstances change and planning is dynamic. He concludes (p. 56) the PJM planning process generally cannot react adequately to changes once a project is approved. Once PJM has approved a line in the RTEP, does PJM continue to consider alternatives to the line and developments?

A. Yes. PJM certainly agrees that changing circumstances may result in the need to adjust the assumptions used in the initial planning studies. For this reason, PJM tracks and records changes to these assumptions, and the planning process provides opportunities for past planning decisions to be adjusted as required. This is the means PJM uses to ensure that the planning process reflects the most current conditions as effectively as possible. Faced with changing system conditions, if the timing and nature of future criteria violations and the progress of construction of previously identified transmission upgrades allow, such upgrades may be deferred or even eliminated, and the transmission plan will be adjusted accordingly. PJM's planning studies, however, continue to demonstrate that the 502 Junction–Loudoun Line is needed in 2011 to resolve a number of reliability criteria violations. The 2006 RTEP analysis identified these NERC criteria violations, and these reliability violations – the same ones identified in Mr. Gass' direct testimony – were the basis for the recommendation to include the 502 Junction – Loudoun Line in the RTEP, as well as the basis for the PJM Board's approval of the Project.

Q. Are these results consistent with the Bates White Supplemental Report dated January 28, 2008?

A. Yes. As reported on page 2 of the Supplemental Report, Bates White conducted NERC N-1 Category B contingency analyses using the most "up-to-date" PJM RTEP base case for the year 2012, reflecting changed system conditions beyond those modeled in either the 2006 or 2007 RTEP analyses, and found that both the original and the updated Bates White contingency analyses indicated major reliability violations in 2011 and 2012 on the

Mt. Storm-Doubs 500 kV Line in the case of a loss of the Mt. Storm-Greenland Gap, Black Oak-Bedington, Greenland Gap-Meadowbrook, or Hatfield-Black Oak 500 kV transmission lines in the absence of major transmission system expansion such as the proposed 502 Junction – Loudoun Line. According to Bates White, "the need for the proposed Loudoun Line persists even when the most "up-to-date" power plan case is used as a basis for the reliability study."

Q. Dr. Merrill (p. 21) claims in his testimony that PJM now says that the 502 Junction – Loudoun Line is merely a temporary one-year solution to the overload problems. Mr. Orans (p. 24) makes a similar statement claiming the Project will serve to mitigate this risk for only one year upon completion. Did PJM make this statement and is this true?

A. No. PJM has never indicated that the 502 Junction – Loudoun Line is a temporary solution. The Project is one component of a comprehensive long range plan to serve the region. It is not, and is not meant to be, a band aid or temporary fix. Just as the Mt. Storm – Doubs Line built in the 1960s has served the overall needs of Virginians for decades, so would the 502 Junction – Loudoun Line. The 2007 load forecast demonstrates that the need for the Project is even more critical than shown in the 2006 RTEP. A number of system changes have been integrated into the 2007 RTEP baseline analysis and subsequent analyses that indicate increased flows to the eastern portion of PJM beyond what had been projected in the 2006 RTEP.

Q. Did PJM re-evaluate the decision to order the construction of the 502 Junction – Loudoun Line in the 2007 RTEP, and are Mr. Orans (p.7) and Dr. Merrill (p. 65) correct that PJM never studied the effect of the PATH Line on the need for the 502 Junction – Loudoun Line?

A. As I have discussed, conditions have changed since the 2006 RTEP. The 2007 RTEP analysis showed that the reliability criteria violations identified in the 2006 RTEP had become ***more severe*** in the 2007 RTEP, and the scope of the violations identified in the 2007 RTEP indicate that both the 502 Junction–Loudoun Line and an additional Amos-Kemptown 500 kV Line, or PATH will now be required to address NERC criteria violations. The 502 Junction – Loudoun Line is needed in 2011 to resolve a number of reliability criteria violations. These violations were identified in the 2006 RTEP analysis and were the basis of the recommendation to include the Project in the RTEP and the basis of the PJM Board's approval of the proposed line. The Amos – Kemptown Line is required in 2012, and the 502 Junction–Loudoun Line continues to be required in 2011.

Q. Have conditions continued to change since the completion of the 2007 RTEP analysis that provided the justification for the Amos – Kemptown Line?

A. Yes. As I've mentioned, system conditions and study assumptions are continually changing. Since the approval of the Amos – Kemptown Line by the PJM Board in June 2007, PJM has integrated a number of changes into the RTEP analyses. For example, the revised route for the 502 Junction – Loudoun Line has been integrated into the RTEP. The current RTEP also reflects generation additions and the return to service of previously retired generators. Significantly, the retirements of the Benning Road and Buzzard Point generators in Washington, D.C. were announced and this event was also modeled. Lastly, a merchant transmission project delivering capacity and energy from New Jersey to New York City has proceeded to the point of executing a Facilities Study Agreement ("FSA") and must also be included in ongoing RTEP analysis. Some of these factors have a very direct impact on reliability criteria violations related to the need for the 502 Junction – Loudoun Line. Even when these changes are taken into account, the results of ongoing PJM's RTEP analyses confirm that the Amos – Kemptown Line is still required in 2012 and the 502 Junction – Loudoun Line continues to be required in 2011.

Neither line obviates the need for the other; the 2007 RTEP demonstrates that both lines are required to relieve identified reliability violations.

Q. Dr. Merrill (p. 19) states that the 2012 base case has a "fatal flaw" because it assumes no new generation is built in eastern PJM between now and 2012. Is this assertion correct, and why does the 2012 base case accurately reflect new generation?

A. As I discussed earlier there is no flaw in the 2012 base case. PJM applies standard rules for the incorporation of new generation into the RTEP base cases. To date, the 2012 base case does not show new generation sufficient to alleviate the need for the 502 Junction – Loudoun Line.

IV. NEW GENERATION AS AN ALTERNATIVE AND THE PJM QUEUE PROCESS

Q. Mr. Orans (p. 10) states that the best solution to reliability problems would be building new generation, "located either within Virginia, . . . or within the load centers primarily served by the Doubs line to directly reduce the amount of energy flowing on the line." Mr. Orans (p. 3) also states that there are substantially more interconnection requests in the mid-Atlantic region than were used by PJM and Dominion in their analysis. Do you agree with their conclusions?

A. PJM cannot rely on the projected building of new generation to ensure reliability on the grid. PJM does not have the ability to require the building of new generation, and, as such, PJM must incorporate new generation conservatively in order to ensure that grid reliability is maintained. As noted by Bates White (p. 82, ¶ 221), adding generation at the Doubs and Bedington buses in the Allegheny Power control area could have a beneficial impact. However, new generation, even if PJM could direct this solution, is not an instant cure, as Mr. Orans suggests. Bates White (p. 82, ¶ 224) concludes ". . . without the proposed Loudoun Line (or other feasible alternatives described in this report) in service by 2011, contingency overloads at various 500 kV transmission lines are expected to occur, even if 4,000 MW of capacity is added to the existing system. . . . In addition new generation resources at the 'wrong' location actually aggravates the severity of the expected reliability violations in 2011."

Q. Dr. Merrill (p. 40) states the 2012 base case study shows that generation in the eastern portion of PJM is increasing and therefore the need for the 502 Junction–Loudoun Line is being misrepresented by PJM. Do you agree with this statement?

A. No. PJM cannot include new generation in the queue without adherence to the specific rules that PJM utilizes to evaluate whether new generation can be relied upon to offset reliability problems on the system.

Q. Please explain how generation interconnection requests in the queue are incorporated into the planning process.

A. PJM utilizes specific rules concerning the inclusion of potential generation projects in the planning process. These rules are based on the need to provide as much certainty as is reasonably possible. In PJM's planning process, new generation can be relied on to resolve reliability criteria violations after the developer executes an Interconnection Service Agreement ("ISA"). Before this point, the dropout rate for generation projects is just too high – and the likelihood of timely construction too remote – to justify forestalling other, more certain solutions. In fact, PJM's generation interconnection queue has experienced approximately a 70% dropout rate based on all projects initially submitted for consideration. Ignoring interconnection projects that involve upgrades to existing generation, which have a somewhat higher completion rate, over 75% of interconnection requests involving new generation plant are eventually withdrawn.

At the time PJM studied the 502 Junction – Loudoun Line, PJM considered new generation in the queue if an executed ISA was in place. It would be imprudent to depend on generation projects, such as CPV Warren for example, at earlier stages of the interconnection process when, statistically, they have a reasonable probability of being withdrawn rather than placed into service. As ISAs are executed by generation projects, they are included in RTEP analyses, not as alternatives to other solutions, but as an integrated component of the baseline system. As these generators are added to the baseline system, previously identified transmission solutions are re-evaluated to determine whether they are still required.

Q. How are new generation solutions integrated into the RTEP?

A. All generation projects with completed System Impact Studies and executed FSA's are included in the power flow models used to perform the RTEP analyses. A Facilities Study is the point in the process where the design work is completed. The earlier studies, the Feasibility Study and the System Impact Study, identify any problems that are caused by the project. Generation projects that have executed an FSA but have not yet executed an ISA are included in all analyses where they will contribute to the possible criteria violations. This is done to ensure that any proposed transmission plans are sufficiently robust to provide for all transmission service needs. However, generators without executed ISAs are not utilized to resolve or back-off potential criteria violations. As discussed, the timely resolution of reliability criteria violations requires a high degree of certainty as to the ultimate completion of market-based generation solutions.

As new generators execute ISAs, they are included in RTEP analyses in the same manner as existing, in-service generators. With respect to load deliverability, new generators in an otherwise constrained area will reduce the amount of energy that area must be able to import under the criteria, reducing the amount of transmission transfer capability required into that area. With respect to generation deliverability, new generators in an otherwise constrained area will tend to balance and, therefore, reduce the flow of energy on critical transmission facilities from generators in other portions of the system. New generators are similarly modeled with respect to all other reliability criteria tests, such as NERC Category C3, and, when located in otherwise constrained areas, can have beneficial impacts on compliance with those criteria and reduce the transmission transfer capability required to achieve compliance with those criteria.

Q. Please respond to Dr. Merrill's (p. 16) assertion that DVP's generation is a net exporter of generation and therefore the 502 Junction – Loudoun Line is not needed.

A. DVP is not a net exporter of generation as further explained in the testimony of Mr. Ronnie Bailey. In fact, both DVP and the Commonwealth of Virginia, as a whole, are significant net importers of generation.

Q. Dr. Merrill (pp. 16-17) states that "... a new 640 MW generation project in Maryland was modeled in 2011 and 2012 studies" – but this generator, while modeled in the 2011 and 2012 load flow databases, is turned off. Can you explain this alleged flaw in the PJM studies?

A. At the time of the development of the 2006 RTEP base case for 2011, this project, holding queue designation G51_W62, had executed a FSA but had not yet executed an ISA. As a result, and as explained above, that project was included in the 2011 base case, but would not be used to resolve identified reliability criteria violations. Before the development of the 2007 RTEP base case for 2012, project G51_W62 executed and then suspended an ISA. PJM does not allow a project with a suspended ISA to resolve identified reliability criteria violations due to the uncertainty related to the project as to its eventual in-service date or even its eventual completion.

Q. Dr. Merrill (p. 19) asserts that the projection of overloads on the Pruntytown – Mt. Storm – Doubs 500 kV Lines is "not supportable." Please explain how PJM determines that these overloads are expected to occur and why the projection of overloads is correct.

A. Dr. Merrill's assertion is based on his claim that greater amounts of eastern generation will be built and should have been included in PJM's analysis. PJM's procedures for including generators in RTEP analyses are based on the high drop-out rate among queued generators and the need for as much certainty as possible when identifying reliability criteria violations. As I have said, generation (excluding upgrades) in the interconnection queues is spread widely across the PJM system and has an approximately 75% drop-out rate. PJM cannot ignore future reliability criteria violations on the unsupported hope that some number of proposed generation projects may proceed and go into service in a timely manner. The consequences of reliability criteria violations can be significant, and PJM has observed numerous instances where generation developers have touted projects as real only to later remove them from the interconnection process. As projects move forward to the point of executing ISAs, they will be considered in future RTEP analyses, including reviews of the continuing need for previously approved transmission projects. However, even the ISA is not a perfect indicator of the eventual completion of a generation project. Projects have been abandoned even after the start of construction. To consider projects earlier in the process, and even less certain of completion, would be imprudent.

Q. Mr. Bouford (p. 10) contends that the CPV projects will address the identified reliability violations and make the 502 Junction – Loudoun Line unnecessary. Will you please address that contention?

A. Mr. Gass shows in his rebuttal testimony that Mr. Bouford's position depends completely on his willingness to make assumptions that PJM, in its planning processes, determined are unsupportable. None of these assumptions, as Mr. Gass notes, was a part of PJM's 2006 RTEP, nor are any of them warranted now. The uncertainty attendant to the construction, timing, and availability of new generation – reflected in PJM's interconnection queue experience and discussed above – applies to both of the CPV projects.

Q. CPV witness Ms. Segner (p. 8) among others indicates that building generation near load areas can obviate or postpone the need to build new transmission lines. Is that correct?

A. On the surface that can seem plausible. However, interconnecting new generation reliably with the transmission system involves completing complex generation interconnection studies. It is not necessarily the case that generators located within a particular state or transmission owner service territory would be found to contribute to the resolution of specific transmission criteria violations, in this case the Mt. Storm – Doubs Line. Based on the specific configuration of the electrical connection to the grid, a given generator may increase or decrease flows on constrained transmission facilities.

Q. Has the Warren Site ever been evaluated by PJM for deliverability without the 502 Junction – Loudoun Line in service?

A. Yes. This site among others was evaluated prior to Dominion integrating its transmission system with PJM in May 2005. The CPV Warren project along with projects at Bath County, Waverly, North Anna, Surry, and Buckingham were found to be not deliverable by PJM in this analysis.

Q. What specifically caused these generation facilities to be declared not deliverable?

A. These proposed generation facilities were found to be contributing to overloads on the Mt. Storm – Doubs 500 kV Line, Bristers – Ox 500 kV Line and the Loudoun –

Morrisville 500 kV Line. Interestingly, as noted on Bates White, Table 48, the proposed Warren Site would contribute to overloads of many of these same lines if it is built and the 502 Junction – Loudoun Line is not in service.

V. MARKET BASED SOLUTIONS AS ALTERNATIVES TO THE PROJECT

Q. Please describe the opportunities available to DR programs in the PJM markets.

A. PJM implements five types of markets in which demand response programs are eligible to participate. These markets are as follows:

1. Capacity Market
2. Economic Energy Market
3. Emergency Demand Response Option
4. Spinning or Synchronous Reserves Markets
5. Regulation Market

Resources may participate in the capacity market, through the RPM auctions as either Interruptible Load for Reliability ("ILR") or as DR programs. The business rules governing the participation of ILR and DR resources are provided in the PJM Manuals. Response, under the circumstances described in the Manuals, is mandatory for the capacity market and as a result, ILR and DR resources are utilized, as described elsewhere in this testimony, to back-off load deliverability criteria violations.

Q. Bates White (p. 90, ¶ 251) concluded that "PJM DR is not a feasible alternative to the proposed 502 Junction – Loudoun Line in terms of reliably meeting the expected 2011 demand." Does PJM consider DR programs in its analyses and what conclusions did PJM reach?

A. PJM includes DR programs in RTEP analyses in two ways. Capacity-related DR resources, such as those committed through RPM auctions, are utilized when evaluating load deliverability criteria as these assessments model the circumstances when such resources would be expected to be utilized to reduce system load. Voluntary programs, including those related to energy efficiency, are integrated through future load forecasts as they impact current energy use. The anticipation or the possibility of increasing participation in either type of program does not provide the certainty required to justify consideration of such programs as solutions with respect to future criteria violations. Based on current DR commitments, PJM agrees that these programs are not a feasible alternative to the proposed 502 Junction – Loudoun Line.

Q. Are there instances in which market-based efforts, such as new generation and DR, cannot be considered as adequate solutions to identified reliability problems?

A. Yes, indeed – the circumstances presented in this case are a good example. When reliability needs are not addressed through the marketplace, PJM must act to address those needs through the planning process by providing new transmission. This is clearly recognized by Bates White (p. 3, ¶ 9) as well, which states, that the "mid-Atlantic region and the northern Virginia area face reliability issues in the near term that must be addressed with a high level of certainty. It would be highly risky to rely on market forces to resolve reliability issues."

Q. Is PJM permitted to wait for the development of market-based efforts to arise, in the hope that they will forestall or obviate the need for a transmission-based solution such as the 502 Junction – Loudoun Line?

A. No. PJM, which is mandated to ensure system reliability, must plan for a reliable system. PJM cannot opt to sit back and wait to see whether uncertain market solutions will be effective. It would be imprudent to delay or eliminate the 502 Junction – Loudoun Line based on a hope that market-based generation or demand response solutions will be effectively implemented to resolve known impending reliability criteria violations. The need for the Project is too immediate, and the violations too significant, to justify waiting for uncertain market solutions.

PJM is not able to direct the siting, timing and location of new generation or the implementation or effect of DR programs – a fact that no party in this case has contested. Consequently, although PJM fosters market-based efforts, its ability to assume their existence as a means to address identified reliability violations is severely – and appropriately – constrained.

Q. What factors associated with market-based solutions tend in some cases to make them unreliable alternatives to new transmission facilities?

A. As I mentioned above, there are distinct difficulties in relying on the availability of new generation projects, and PJM has a defined process (expressed in PJM's FERC-approved tariff) that attempts to take these uncertainties into account. Additionally, in order for DR efforts and new generation to be relevant to addressing the reliability violations PJM has identified, they must be (i) targeted to the precise location needed (in this case, directly east of the Doubs substation), not placed generally within the PJM Region, and (ii) sufficiently predictable (especially in the case of DR programs) to be relied upon.

Moreover, timing is also critical when PJM identifies transmission solutions. PJM's ability to further consider developing market solutions is dependent on the timing of the initial reliability need and the time required to implement the transmission solution. If PJM can identify reliability violations sufficiently far into the future, PJM will still plan appropriate transmission solutions, but time will remain for market-based solutions to develop to a point where these solutions could delay or even eliminate the need for a transmission solution. In this case, there are not sufficient market-based solutions in place, or in development, that will eliminate the need for the Project. Other than in the testimony of CPV Warren witness Mr. Bouford in this case (which Mr. Gass will address), no witness or party in this case has attempted to identify a market-based solution that we could count on to address the reliability violations PJM has identified, and no party has provided any assurance that these solutions will be in place by June 2011, when the reliability issues are projected to arise. Therefore, PJM will continue to proceed with the Project as the best solution to the identified reliability criteria violations.

Q. Mr. Orans suggests that PJM can rely on the success of RPM to bring increased generation into the region and thus obviate the need for the 502 Junction – Loudoun Line. (p. 10) Please explain why RPM is not an adequate substitute for building the Project.

A. The RPM establishes the locational capacity value of generation and demand response resources. RPM auctions are used to secure installed capacity resources required to satisfy the Installed Reserve Margin, the amount of generation required across PJM to ensure a resource-based loss of load expectation of no more that one day in 10 years. Recognizing that load, generation and transmission capability must be balanced in all parts of the PJM system, RPM establishes a higher price for capacity in areas where that balance is deficient. Load deliverability testing serves as the basis for price separation in RPM auctions, which provide incentives for the development of generation and demand response resources in constrained areas of the system. Through the transparent planning process, PJM shares a wide range of planning information with stakeholders, including load forecasts, the identification of future potential criteria violations, and load deliverability margins. Developers can utilize this information as well as other market signals over the 15-year planning horizon, to anticipate areas where capacity prices will be higher and their resources more valuable. If the market provides for the assured development of sufficient resources to mitigate future reliability criteria violations, further transmission system upgrades may become unnecessary. If the signals provided through the RTEP process and through the RPM auctions are ignored, and reliability criteria violations develop in the future, then the annual RTEP process must identify the transmission system upgrades required for the system to remain compliant with reliability criteria.

While PJM has seen an increase in the number of generation projects proposed in eastern PJM since the implementation of the RPM auctions, these projects are still very early in the interconnection process. Due to the high rate of withdrawal of projects from the interconnection queue, these projects cannot be assumed to contribute to the mitigation of reliability criteria violations until they have executed an ISA. As these projects continue to move forward in the queue process to the point of executing ISAs they can then, potentially, help to defer or eliminate the need for baseline transmission upgrades that were otherwise identified to resolve criteria violations. With respect to the 502 Junction-Loudoun Line, sufficient resources have not proceeded to the point of executing an ISA to obviate a need for the 502 Junction – Loudoun Line.

As discussed earlier, while there has been an increased volume of requests entered into the interconnection queue since the filing at FERC 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 the Project do not allow PJM to delay in the hope that a sufficient number of these projects will proceed to completion to defer or obviate the need for the 502 Junction – Loudoun Line.

VI. ECONOMIC IMPACTS OF THE PROJECT

Q. Mr. Walker's (p. 2) testimony references an analysis of the economic impact of the Project performed by PJM. Why did PJM perform this study?

A. PJM developed this study through its 2006 market efficiency analysis to be indicative of the general impacts that a backbone transmission project will have on the performance of the PJM market. The analysis was later used through the Regional Planning Process Working Group in order to develop and file specific market efficiency planning process procedures with FERC. It is important to remember that the Project is driven by reliability, and not economic impacts. The market efficiency analysis was not performed as justification for the Project.

Q. How were the numbers in these reports developed and intended to be used?

A. These results are based on annual market simulations made with and without the 502 Junction – Loudoun Line. Economic parameters between the two simulations were compared to determine the economic impact of the Projects. The economic impact of the Project was determined in this way under various future scenarios for numerous simulated future years. Because the Project was approved based on the need to resolve a number of reliability criteria violations, and because PJM must make uniform assumptions about participant market behavior, the Financial Transmission Rights ("FTRs") credits reflect 100% of the FTRs for the zone. Therefore this is not directly applicable to determining the cost of service in a zone. The cost of service to individual groups of customers will depend on the specific business strategy implemented by the market participant as well as the change in the configuration of the network.

Q. In his testimony, Mr. Walker (p. 1) asserts, "the project will decrease transmission congestion and provide cheaper generators greater access to loads." Do you agree with this statement?

A. Mr. Walker is correct that the Project will have the effect of reducing transmission system congestion, thereby providing load customers access to a wider range of less expensive generation resources and, similarly, providing those less expensive generators greater access to a wider range of load customers.

Q. Do you agree with Mr. Walker's (p. 3) assessment that the Project will initially increase and later decrease overall annual generating revenues?

A. The simulation results show that, as expected, the generators on the eastern side of the constraints relieved by the Project will experience lower gross generator revenues, and the generators on the western side of the constraints relieved by the Project will experience higher gross generator revenues. In the earlier simulated years, the magnitude of the increased western generator revenue is greater than the magnitude of the decreased eastern generator revenue such that the net impact across the entire system is an increase in total PJM generation revenue. The simulation shows this trend reversing, however, and a decrease in total generation revenues occurs as early as 2010.

Q. Mr. Walker (p. 5) states that the PJM analysis implies that the Project will increase power supply costs in the Dominion zone by $51.1 million, and this cost impact would be in addition to the Dominion zone's share of the annual revenue requirements of the Project. Dr. Merrill (p. 5-6) also states that ratepayer costs will go up in the 2010 test year if the 502 Junction–Loudoun Line is built. Do you agree with these conclusions?

A. Mr. Walker extrapolates the PJM zonal results to determine state impacts of the Project and this may lead to somewhat distorted results in the Dominion as well as the Allegheny Power zones. Also, Dr. Merrill bases his conclusions on a one year analysis, which is also misleading.

The PJM analysis results are reported on a zonal basis where a zone is defined geographically and the generation energy, production cost and gross revenues for all generation located within a zone's boundaries are reported as belonging to this zone whether or not there is a commercial relationship between that zone's load and any particular generator physically located within the zone. PJM does not make assumptions regarding commercial transactions between various market participants and reports the results on a zonal basis to get a more granular, geographic view of a given project's economic impact. It is important to remember that the indicative zonal output of PJM studies may vary significantly from the actual zonal impact due to business strategies employed by individual members. Finally PJM considers only the wholesale impacts of the Project in its analysis. Revenue flow to retail customers in each state will, of course vary. The calculations in no way can be considered a proxy for a retail revenue requirement and should not have been used in that fashion by Mr. Walker or Dr. Merrill.

Q. Mr. Walker (p. 6) states PJM's analysis represents an "incredibly complex set of assumptions and conditions" and results may vary greatly from the projections. Can you address the complexity of the analysis and the predictability of its projections?

A. The analysis is based on annual simulation of the hour-by-hour security-constrained commitment and dispatch of generation to meet load. Simulation inputs include assumptions on zonal peak load and energy, future new or retired generation, fuel costs, emissions costs and other generator attributes. While complex and data intensive, this type of simulation analysis is used widely in the industry to forecast the economic impact of system changes and produce reasonable estimates of the change in generation dispatch, costs and Locational Marginal Prices ("LMPs") associated with a congestion-relieving project.

That said, Mr. Walker is correct with respect to the complexity of production cost simulations. The models that PJM uses represent the bulk of the eastern United States and require a wide range of assumptions about future conditions. If the Project were being justified on its economic merits, a wide range of simulations would need to be performed to understand the sensitivity of results to each of a number of modeling assumptions. However, the Project has been identified as necessary to resolve a number of NERC reliability criteria violations. The production cost simulations referenced by Mr. Walker were performed to illustrate the development of PJM's market efficiency planning process. What is clear from those simulations is that the Project brings economic benefits in addition to its reliability value. PJM recognizes that it is difficult to predict economic conditions far into the future, but it is clear that the Project brings net economic benefits over a wide range of future system conditions.

Q. Also Dr. Merrill (p. 5 and 9) suggests that the 502 Junction – Loudoun Line will reduce congestion and subsequently increase profits to generators. Do you have any comment on this?

A. All transmission projects of any significance should be expected to reduce transmission congestion and, therefore, to increase profits to some generators and decrease profits to others. The 502 Junction – Loudoun is required to address a number of reliability criteria violations projected to occur beginning in 2011. While it results in net economic benefits to the PJM grid, it was not proposed nor justified on the basis of those benefits.

Q. Do you have any comment about Ms. Segner's (p. 9) assertion that the Project will actually worsen the problem of inadequate generation in eastern PJM by making western energy appear cheaper than it is?

A. The addition of transmission capability cannot make any generation "appear cheaper than it is." The security-constrained economic dispatch employed by PJM will continue to drive the utilization of the most cost-effective resources required to serve the aggregate load within the PJM region while respecting any transmission constraints on a day-ahead and real time basis. The 502 Junction – Loudoun Line is intended to address specific reliability violations on the PJM grid. The 502 Junction – Loudoun Line is not designed to deliver specific generation from western PJM to the eastern PJM region, nor is it specifically designed to carry inexpensive generation from the west. Our forecasts show that new generation is continuing to be developed, but not fast enough nor in sufficient amounts to obviate the need for new transmission. Continued load growth in eastern PJM will, if not coupled with the development of sufficient amounts of low-priced local baseload generation, result in high energy prices in eastern PJM over the long-term.

Additional transmission will allow resources outside of these eastern load centers to help serve the reliability needs of the eastern load, but will not obviate the need for additional eastern resources in the future. Therefore, the 502 Junction – Loudoun Line may temporarily moderate energy prices in eastern PJM, but it will not eliminate all causes of the transmission congestion faced by load customers in eastern PJM.

Q. What impact will the 502 Junction – Loudoun Line have on PJM's capacity markets?

A. As with energy prices, the 502 Junction – Loudoun Line will initially moderate the degree of price separation experienced in the capacity markets with respect to Locational Deliverability Areas in eastern PJM. However, capacity prices throughout PJM will increase if future load growth is not matched by the continued development of generation resources, and capacity prices in eastern PJM will rise above those in the west if a sufficient proportion of those resources is not developed near eastern load centers.

Q. Dr. Merrill (p. 31) states that the applicants have chosen a base-case dispatch for economic rather than reliability reasons and that the driver for the Project is really to provide a boon to owners of western coal-fired plants. Can you address this assertion?

A. Dr. Merrill is incorrect and provides no support for his claim. PJM's RTEP process is driven by eliminating reliability concerns, not to enhance any particular generation resources. The RTEP base-case models a statistically determined dispatch which, if anything, reduces the output of coal-fired generators below the levels that would result from an economic dispatch. PJM's load and generation deliverability base-cases model critical system conditions that ignore fuel type. Furthermore, it is not accurate to single out coal-fired generation as the sole beneficiary of grid improvements. I have reviewed the active queued generation projects proposed since the approval of the 502 Junction – Loudoun Line by the PJM Board. There are approximately 7,700 MW of coal projects active in the queue, approximately 19,200 MW of natural gas projects and 25,600 MW of wind projects proposed in PJM since July 2006. Deliverability of non-coal resources, such as wind generation, will clearly benefit from the enhanced transfer capability that results from the addition of the 502 Junction – Loudoun Line.

There are many factors that impact the decisions of developers as to what fuel type generation to build. Transmission is only one factor. The RTEP process cannot dictate the types of resources to be built or the location of resources. These are decided by developers in the market based on a wide range of factors. Transmission facilities identified as needed to satisfy baseline reliability criteria violations are not developed to deliver individual resources or certain types of resources. They are identified to restore the ability of the transmission system to deliver the aggregate of all resources in accordance with criteria. Finally, I would note that the operation of coal fired generation resources is the subject of extensive regulation by Federal and State environmental agencies. Those agencies will determine the permissible parameters for future operation of coal-fired generation facilities, separate and apart from any regional grid improvements.

Q. Dr. Merrill (p. 42) states that coal-fired plants take longer to build than gas-fired plants, so the queue will show more coal than gas plants at any point in time. Consequently, the planning database shows an unrealistic slant toward coal plants. Is there an imbalance in PJM's analysis as Dr. Merrill claims?

A. No, and there is no basis for this assertion. Coal-fired plants and gas-fired plants react to the same market forces. A coal-fired plant would decide to enter the market at a certain point in time and submit a queue request based on a business decision considering all of those market forces weighed against the costs to plan and build a coal-fired plant. This is the same type of business decision that a gas-fired plant developer would have to make as well. There is no basis to conclude that a coal-fired plant developer can somehow foresee market forces or need into the future any differently than the developer of a gas-fired plant. Further, the queue does not show a slant toward coal-fired plants as Dr. Merrill suggests, in fact as I have already stated, the present queue shows more gas-fired plants than coal-fired plants.

Q. Does this conclude your rebuttal testimony?

A. Yes.