BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Transource Pennsylvania, LLC filed Pursuant to 52 Pa. Code Chapter 57, Subchapter G, for Approval of the Siting and Construction of the 230 kV Transmission Line Associated with the **Independence Energy Connection-West Project** in Portions of Franklin County, Pennsylvania	Docket No. A-2017-____________

Transource Pennsylvania, LLC
Independence Energy Connection-West Project

Statement No. 3

Written Direct Testimony of
Paul F. McGlynn

Topics Addressed: **The PJM Process**
The Need for the Independence Energy Connection Project

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul F. McGlynn, and my business address is 2750 Monroe Boulevard, Audubon, Pennsylvania 19403-2497.

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

A. I am employed by PJM Interconnection, L.L.C. ("PJM"), a regional transmission organization ("RTO"), as Senior Director, System Planning.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE AND EDUCATIONAL BACKGROUND.

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

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

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

I am a licensed Professional Engineer in the Commonwealth of Pennsylvania. I hold a Bachelor of Science degree in Electrical Engineering from the Pennsylvania State University and a Master of Science degree in Electrical Engineering from Drexel University.

Q. PLEASE DESCRIBE THE PURPOSE OF YOUR TESTIMONY.

A. I have been asked by Transource Pennsylvania, LLC ("Transource PA") to describe PJM and its RTEP process. In particular, I will discuss PJM's Market Efficiency Project 9A ("Project 9A") in the context of the RTEP and why Project 9A is needed to alleviate transmission congestion in eastern PJM.[1]

[1] Transource Pennsylvania and its Maryland affiliate, Transource Maryland, LLC ("Transource MD"), are responsible for the construction, ownership, maintenance, and operation of certain components of Project 9A, as described more in detail in this testimony.

Q. PLEASE PROVIDE AN OVERVIEW OF PROJECT 9A.

A. As explained in more detail below, after extensive evaluation and review with stakeholders, PJM selected Project 9A to address significant economic congestion identified in PJM's 2014/15 Long Term Proposal Window because it provided the most benefits, including the most total congestion savings and most production cost savings, and met PJM's Benefit/Cost Ratio. Pertinent to the pending Application, the Independence Energy Connection Project ("IEC Project") is a major component of the Project 9A approved by PJM. The IEC Project involves: (i) construction of two new substations in Pennsylvania, the Rice Substation and the Furnace Run Substation; and (ii) construction of two new overhead double-circuit 230 kV interstate transmission lines, the Rice-Ringgold 230 kV Transmission Line and the Furnace Run-Conastone 230 kV Transmission Line.[2]

Upon receipt of all necessary approvals, the new Rice-Ringgold 230 kV Transmission Line will be sited to extend approximately 29 miles, connecting the existing Ringgold Substation located near Smithsburg, Washington County, Maryland, and the new Rice Substation to be located in Franklin County, Pennsylvania. Transource PA refers to this transmission line project as Independence Energy Connection-West Project ("IEC-West Project").

[2] Project 9A also includes upgrades to the existing Conastone and Ringgold Substations in Maryland and reconductoring of the Conastone-Northwest double-circuit 230 kV line and the Ringgold-Catoctin 138 kV line in Maryland. The upgrades to these existing facilities will be the responsibility of the incumbent utilities. The upgrades to existing facilities, while not part of the IEC Project, are inter-dependent components of the solution approved by PJM.

Upon receipt of all necessary approvals, the new Furnace Run-Conastone 230 kV Transmission Line will be sited to extend approximately 15.8 miles, connecting the existing Conastone Substation located near Norrisville, Harford County, Maryland, and the new Furnace Run Substation to be located in York County, Pennsylvania. Transource PA refers to this transmission line project as Independence Energy Connection-East Project ("IEC-East Project").

As further explained in the direct testimony of Mr. Kamran Ali (Transource PA Statement No. 2) Transource PA will construct, own, operate, and maintain the Pennsylvania portion of the new transmission lines associated with the IEC Project and Transource PA's affiliate, Transource MD, will construct, own, operate, and maintain the Maryland portion of the new transmission lines associated with the IEC Project.

Q. WHAT WAS YOUR ROLE IN THE DEVELOPMENT OF PROJECT 9A?

A. In my role as Senior Director System Planning I was responsible for identifying the need, soliciting proposals, evaluating the proposals and ultimately recommending a project to address the needs to the Board of Managers ("PJM Board" or "Board"). As the chair of the TEAC, I was also responsible for reviewing the needs, proposals and evaluation of the projects with stakeholders.

Q. WHAT TOPICS WILL YOU DISCUSS IN YOUR TESTIMONY?

A. In general terms, I will explain that as a Federally-approved independent RTO, PJM is responsible for ensuring the reliable and efficient operation of the electric transmission system in the PJM region. In order to ensure reliable transmission service, PJM prepares an annual RTEP and applies North American Electric Reliability Corporation ("NERC")

Reliability Standards to evaluate the reliability of the transmission system. PJM determines the required transmission enhancements and expansions that are needed to ensure that the NERC Reliability Standards are satisfied. In addition to the reliability analysis, PJM's RTEP includes a Market Efficiency analysis to identify transmission facilities that may have economic or wholesale market benefits. Pursuant to Federal Energy Regulatory Commission ("FERC") authority, PJM directs, as appropriate, the construction of new transmission projects or upgrades to ensure grid reliability and efficiency. In my direct testimony, I will show that the PJM planning process is open, transparent and collaborative. All decisions and analysis are subject to stakeholder review and participation.

I will also describe the need for Project 9A, and how it was selected as the appropriate means to address the market efficiency needs through the RTEP process, in an open, transparent forum that afforded all stakeholders the opportunity to consider alternative proposals. After extensive evaluation and review with stakeholders, PJM selected Project 9A to address needs identified in PJM's 2014/15 Long Term Proposal Window because it was the most effective solution to mitigate the congestion noted previously. PJM's study results show that Project 9A is needed, and PJM supports the Pennsylvania Public Utility Commission approval of the IEC-West Project and the IEC-East Project, which are the major components of the Project 9A approved by PJM to address the congestion concerns.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section I provides the reasons why PJM selected Project 9A to address, among other things, transmission congestion across the Maryland and Pennsylvania border.
- Section II includes an overview of PJM, including its role as an independent RTO.
- Section III describes PJM's transmission planning process.
- Section IV describes PJM's market efficiency analysis as part of the RTEP process.
- Section V explains how application of PJM's RTEP process identified the need for Project 9A, and the alternatives PJM considered before selecting Project 9A.

Q. WILL THE USE OF VARIOUS TERMS IN YOUR TESTIMONY BE CONSISTENT WITH THE DEFINITIONS ASSIGNED TO THOSE TERMS IN THE GLOSSARY ATTACHED TO THE APPLICATION AS APPENDIX A?

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

I. SUMMARY OF REASONS WHY PJM SELECTED PROJECT 9A

Q. PLEASE SUMMARIZE THE PRIMARY REASONS FOR PJM'S DETERMINATION OF NEED FOR PROJECT 9A.

A. In this direct testimony, I will devote considerable attention to the process PJM uses to perform its RTEP Market Efficiency analysis. This background information is indispensable to a firm understanding of PJM's determination that Project 9A is needed. Yet the attention devoted to this background should not obscure the main message of my testimony — the compelling reasons why Project 9A is needed and the IEC-West and IEC-East Projects should be approved in Maryland and Pennsylvania:

- In October 2014, PJM opened the 2014/15 Long Term Proposal Window to solicit proposals to address, among other things, transmission congestion across the AP-South interface (an area of the PJM transmission grid including the Pennsylvania and Maryland border, described more in detail below). This transmission congestion has existed for an extended period of time, and results in significant transmission congestion costs ultimately borne by residents, commercial businesses and industrial customers in the eastern region of PJM, with the greatest impacts in Maryland and northern Virginia.
- After extensive evaluation of alternatives and review with stakeholders, PJM selected Project 9A to address the needs identified in PJM's 2014/15 Long Term Proposal Window because it provided the highest Benefit/Cost Ratio in terms of reductions in load market payments compared to the project's cost. In addition, examination of other metrics and a range of assumptions showed the project is

expected to produce high levels of transmission congestion savings, and reductions in the variable cost of generation supply to the market.

- Specifically, during its competitive solicitation process conducted in 2014 and 2015, PJM estimated that Project 9A was expected to save customers approximately $620 million over 15 years.

II. DESCRIPTION AND OVERVIEW OF PJM

Q. PLEASE DESCRIBE PJM.

A. PJM is an independent RTO regulated by FERC that is responsible for the planning, operation, and reliability of the interstate electric transmission system under its functional control which spans all or portions of 13 states and the District of Columbia in the mid-Atlantic region.[3] The PJM system serves approximately 65 million customers, and PJM dispatches more than 176,560 megawatts ("MW") of generation capacity over more than 82,540 miles of transmission lines.

PJM presently has more than 1,000 members. These members, who in many cases are also customers of PJM, include power generators, transmission owners ("TOs"), electricity distributors, power marketers and large consumers. PJM has no financial or ownership interest in any PJM member. PJM's role as a Federally-regulated RTO means that it acts independently and impartially in operating and planning the regional transmission system and in overseeing the wholesale electricity market.

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

Q. WHAT IS THE BASIS FOR PJM'S AUTHORITY TO CARRY OUT ITS RESPONSIBILITIES?

A. PJM is one of a handful of FERC-approved and federally-regulated RTOs. PJM has specific duties and responsibilities established by federal law and FERC decisions, and by PJM's own FERC-filed tariffs, agreements, and procedures. PJM's duties include, among other things, ensuring the reliability of the transmission grid in the PJM Region and operating the regional transmission system in a manner consistent with the applicable laws, regulations, and tariffs. PJM's authority with respect to its planning process is based on its role as a FERC-approved RTO and on its authority and responsibilities under the PJM Operating Agreement, the PJM Tariff, and the PJM Consolidated Transmissions Owners Agreement, each of which has been filed with and approved by FERC.

PJM is also responsible for implementing other standards and regulations. For example, FERC has approved the NERC Reliability Standards, and PJM plans and operates the transmission system in accordance with those standards. PJM is also designated by NERC as the Planning Coordinator (formerly called Planning Authority) and the Transmission Planner with respect to compliance with the NERC standards. In so doing, PJM applies reliability requirements adopted by NERC and regional reliability organizations, as well as criteria promulgated by transmission owners. PJM's authority to carry out its responsibilities is established by FERC's approval of the PJM's governing agreements, its approval of the NERC Reliability Standards, and PJM's designated roles with respect to those standards.

Q. WHAT BENEFITS DO MEMBERS DERIVE FROM PJM MEMBERSHIP?

A. PJM continues to operate and plan the transmission system as though it were a single system. Corporate and state boundaries are not considered when taking operational action or making planning decisions. Considerable benefits accrue to the PJM members and their customers through PJM's centralized security-constrained economic dispatch, reserve requirements and coordinated planning. These activities are estimated to produce as much as $3.1 billion per year in benefits and economic value for the region PJM serves.

III. PJM'S TRANSMISSION PLANNING PROCESS

Q. WHAT IS PJM'S ROLE IN TRANSMISSION PLANNING?

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

Q. ARE THE REGIONAL PLANNING PROCESS AND THE ANNUAL RTEP FOCUSED SOLELY ON EXPANSION OF THE TRANSMISSION SYSTEM DRIVEN BY THE NEED TO INCREASE CAPACITY OR ELIMINATE RELIABILITY CONCERNS?

A. No. Our tariff, planning process, and RTEPs recognize several distinct needs for transmission expansion. Addressing reliability issues, whether through increasing capacity, or some other transmission expansion, is just one of those needs addressed through PJM's RTEP process. The full range of needs include:

1. Reliability;
2. Market Efficiency;
3. Operational Performance;
4. Meeting public policy requirements; and
5. Addressing long-term congestion hedging deficiencies.

Q. WHAT IS THE BASIS OF PJM'S TRANSMISSION PLANNING FUNCTION AND AUTHORITY?

A. PJM's authority and obligation to perform this function is established in the PJM Tariff, PJM Operating Agreement and other related agreements and PJM business manuals. The process is overseen by the PJM Board and regulated by FERC.

Q. DOES PJM HAVE A WRITTEN PROTOCOL FOR ITS PLANNING PROCESS?

A. Yes. The RTEP Protocol and PJM's planning role are set forth in Schedule 6 of the PJM Operating Agreement. The purpose and objective of Schedule 6 is stated at section 1.1 and states in pertinent part as follows:

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

Q. WHAT ARE THE PRIMARY ELEMENTS OF PJM'S PLANNING PROCESS?

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

- Forecasted load growth, demand-side-response efforts and distributed generation additions;
- Interconnection requests by developers of new generating resources and merchant transmission facilities;
- Solutions to mitigate persistent economic congestion and to ensure adequate allocation and funding of long-term financial transmission rights;
- Long-term firm transmission service requests;
- Generation retirements and other deactivations;
- Transmission Owner-initiated improvements; and
- Load-serving entity capacity plans.

This process narrows the projects that PJM staff recommends as solutions to the PJM Board to address the various transmission system needs. The PJM Board will then use its authority pursuant to PJM's Tariff to order that a project be constructed.

Q. DOES THE RTEP PROCESS INVOLVE OTHERS OUTSIDE OF THE PJM ORGANIZATION?

A. Yes. The RTEP process is open, transparent and collaborative from start to finish. Forums and processes provide opportunities for stakeholders to help PJM improve the transmission grid, ensuring reliability and access to robust, competitive markets. The activities of the TEAC and the Sub-regional RTEP Committees provide the primary forum for the ongoing exchange of ideas, discussion of issues and presentation of planning findings.

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

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

TEAC participation is open to all transmission customers, any other entity proposing to provide transmission facilities to be integrated into the PJM region, all PJM members, representatives of state commissions, the agencies and offices of state consumer advocates of states in the PJM region, and any other interested parties. This broad group of constituents fosters a wide range of opinions, comments and advice on

RTEP development and recommendations for PJM Board approval. Following the presentation of analysis assumptions or results and project recommendations to the TEAC, stakeholders are invited to provide written comments. These comments are provided to the PJM Board for their consideration and serve as the basis for on-going dialogue at subsequent TEAC meetings.

Q. AFTER THE PROCESS IS COMPLETE, HOW IS THE RTEP APPROVED?

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

Q. FOR CONTEXT, CAN YOU SUMMARIZE THE NATURE AND EXTENT OF THE RTEP PROJECTS ORDERED BY THE PJM BOARD SINCE THE INCEPTION OF THE RTEP PROCESS?

A. Since 1999, the PJM Board has approved transmission system enhancements or expansions totaling approximately $35 billion to ensure compliance with NERC, regional and local Transmission Owner planning criteria. This includes $27 billion of baseline transmission enhancements throughout the RTO region and $7.2 billion of network facilities enabling more than 79,700 MW of new generation to interconnect reliably.

Q. HOW DOES THE PJM RTEP PROCESS DETERMINE WHETHER THERE IS A NEED FOR A NEW TRANSMISSION FACILITY?

A. A proposed project must meet one or more specific criteria as set forth in the PJM Operating Agreement to be included in the RTEP. These criteria include:

1. Reliability standards. The RTEP must "conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, ReliabilityFirst Corporation ("RFC"), and SERC Reliability Corporation ("SERC"), and those of the transmission owners in accordance with the planning and operating criteria and other procedures detailed in the PJM Manuals.[4]

2. Market efficiency. If new facilities can lower costs to customer, and benefits of the project exceeds its costs by or above a certain required ratio, then PJM has the authority to require new transmission to be built. [5]

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

4. Addressing long-term congestion hedging. PJM uses a locational pricing system to manage congestion. Transmission facilities must be built as required to

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

[5] Section 1.5.7(d) of Schedule 6 to the PJM Operating Agreement. There are strict metrics governing market efficiency projects and in PJM the Benefit/Cost Ratio must be greater than or equal to 1.25.

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

maintain feasibility of Stage 1A Auction Revenue Rights, a key feature of this system.[7]

5. State Public Policy through the State Agreement Approach specified in the Operating Agreement.

Finally, the RTEP also includes enhancements or expansions required as a result of coordination with other neighboring planning regions.[8]

Q. ON WHAT BASIS DID PJM THROUGH THE RTEP PROCESS DETERMINE THAT PROJECT 9A WAS NECESSARY?

A. Project 9A was deemed necessary under the RTEP's market efficiency analysis.

IV. <u>PJM'S MARKET EFFICIENCY ANALYSIS</u>

Q. PLEASE PROVIDE AN OVERVIEW OF PJM'S MARKET EFFICIENCY PROCESS.

A. PJM's market efficiency analysis is performed as part of the overall RTEP process to accomplish the following two objectives:

1. Determine which reliability upgrades, if any, have an economic benefit if accelerated (i.e., placed in service prior to their reliability need date).
2. Identify new transmission upgrades that may result in economic benefits.

PJM performs a market efficiency analysis under a 24-month planning cycle. Following the availability of the appropriate updated RTEP power flow model resulting from the reliability analysis, PJM performs its market efficiency analyses to identify market

[7] Section 1.5.3(h) of Schedule 6 to the PJM Operating Agreement.
[8] Section 1.5.5 of Schedule 6 to the PJM Operating Agreement.

efficiency needs on the PJM system. PJM solicits proposals to address identified market efficiency issues at the end of the first year of the 24-month cycle. During the second year of the 24-month cycle, the market efficiency models are updated with the latest assumptions and the proposals are evaluated using those updated models. As a result, there is a mechanism in place for regularly identifying transmission enhancements or expansions that will relieve relevant future congestion as forecasted in the market efficiency analysis.

In the market efficiency analysis, PJM compares the costs and benefits of the economic-based transmission improvement proposals. To calculate the benefits of these potential economic-based enhancements, PJM performs and compares market simulations with and without the newly proposed economic-based enhancements for selected future years within the RTEP's 15-year planning horizon. The relative benefits and costs of the economic-based enhancement or expansion must meet the Benefit/Cost Ratio threshold test to be included in the RTEP recommended to the PJM Board for approval. This test and its implementation are described in detail, below. PJM presents all the RTEP market efficiency enhancements to the TEAC for review and comment. Subsequent to TEAC review, PJM considers stakeholder comments and presents the final recommended market efficiency projects to the PJM Board, along with the advice, comments, and recommendations of the TEAC, for Board approval.

Q. WHO MAY SUBMIT PROPOSALS FOR EVALUATION UNDER THE MARKET EFFICIENCY ANALYSIS?

A. Any qualifying entity (consistent with PJM Operating Agreement Schedule 6 provisions), may formally submit proposals in the RTEP proposal window for evaluation under the market efficiency analysis. These proposals will be posted on the PJM Website.

Q. PLEASE DESCRIBE IN DETAIL PJM'S MARKET EFFICIENCY ANALYSIS.

A. PJM's market efficiency analysis involves several phases. The process begins with the determination of the congestion drivers that may signal market inefficiencies. PJM collects and publicly posts relevant drivers. In addition, PJM performs market simulations to determine projections of future market congestion based on the anticipated RTEP upgraded system. This process facilitates concurrent PJM and stakeholder review of the same information considered by PJM in preparation for PJM's solicitation of proposals for upgrades that may economically alleviate market inefficiencies. Following the evaluation of congestion drivers and solicitation of proposals, PJM evaluates the economic costs and benefits of any identified new potential upgrades targeted specifically at economic efficiency.

Q. PLEASE DESCRIBE IN GREATER DETAIL THE COST/BENEFIT ANALYSIS THAT PJM PERFORMS AS PART OF ITS MARKET EFFICIENCY ANALYSIS.

A. PJM uses a Benefit/Cost Ratio test to determine whether an economic-based enhancement or expansion will be included in the RTEP. Specifically, to be included in the RTEP recommended to the PJM Board for approval, the relative benefits and costs of the economic-based enhancement or expansion must meet or exceed a Benefit/Cost Ratio threshold of at least 1.25:1. The Benefit/Cost Ratio is calculated by dividing the present value of the total annual benefit for each of the first 15 years of the life of the enhancement or expansion by the present value of the total annual cost for each of the first 15 years of the life of the enhancement or expansion. Assumptions for determining the present value of the benefits and costs (e.g., discount rate and annual revenue requirement) will be among the assumptions that are considered by the PJM Board each year to be used in the economic planning process. The Benefit/Cost Ratio is expressed as follows:

> Benefit/Cost Ratio = [Present value of the Total Annual Enhancement Benefit for each of the first 15 years of the life of the enhancement or expansion] ÷ [Present value of the Total Enhancement Cost for each of the first 15 years of the life of the enhancement or expansion]

The purpose of a Benefit/Cost Ratio threshold is to hedge against the uncertainty of estimating benefits in the future and to provide a degree of assurance that a project with a 15-year net benefit near zero will not be approved. At the same time the threshold is not so restrictive as to unreasonably limit the economic-based enhancements or expansions that would be eligible for inclusion in the RTEP.

Q. HOW IS THE BENEFIT COMPONENT OF THE BENEFIT/COST RATIO CALCULATED?

A. The benefit component of the Benefit/Cost Ratio (Total Annual Enhancement Benefit) is the sum of two metrics: the "Energy Market Benefit" and the "Reliability Pricing Model (RPM) Benefit." By including these two metrics, the benefits to customers from reductions in both energy prices and capacity prices as a result of an economic-based enhancement or expansion will be taken into account in the formulaic analysis. This comprehensive test captures customers' benefits in the energy markets and the capacity markets that may correspond to responsibilities related to obtaining reasonably priced energy as well adequate capacity.

Q. HOW DOES PJM CONDUCT THE ENERGY-MARKET BENEFIT ANALYSIS?

A. The energy-market benefit analysis is conducted using an energy market simulation tool that models the hourly least-cost, security-constrained commitment and dispatch of generation over a future annual period. A detailed generation, load, and transmission system model is used as input into the simulation tool in order to mimic the hourly commitment and dispatch of generation to meet load, while recognizing constraints imposed on the economic commitment and dispatch of generation by the physical limitations of the transmission system. PJM will perform and compare market simulations with and without the proposed enhancement for selected future years within the planning horizon of the RTEP in order to measure the benefits of potential economic-based enhancements. A comparison of these simulations will identify the annual economic impact of the enhancement for each of the future study years. An interpolation and extrapolation of these results provides a projection of annual benefits for each of the first 15 years of the life of the enhancement.

The Energy Market Benefit component of the Benefit/Cost Ratio for Regional Projects is expressed as:

Energy Market Benefit = [.50] * [Change in Total Energy Production Cost] + [.50] * [Change in Load Energy Payment]

The Energy Market Benefit component of the Benefit/Cost Ratio for Lower Voltage Projects is expressed as:

Energy Market Benefit = [1] * [Change in Load Energy Payment]

The Change in Total Energy Production Cost is the difference in estimated total annual fuel costs, variable operation and maintenance ("O&M") costs, and emissions costs of the dispatched resources in the PJM Region without and with the enhancement or expansion. Costs for purchases from outside of the PJM Region and sales to outside the PJM Region will be captured if appropriate. Purchases will be valued at the Load Weighted Locational Marginal Price ("Load Weighted LMP") and sales will be valued at the Generation Weighted Locational Marginal Price ("Generation Weighted LMP").

The Change in Load Energy Payment is the difference between the annual sum of the hourly estimated zonal load megawatts for each PJM transmission zone multiplied by the hourly estimated zonal Locational Marginal Price ("LMP") for each PJM transmission zone minus the value of Transmission Rights for each PJM transmission zone with and without the economic-based enhancement or expansion. In determining the Change in Load Energy Payments, only zones that show a decrease will be considered in determining the Change in Load Energy Payments.

Q. PLEASE FURTHER EXPLAIN THE RELIABILITY PRICING BENEFIT ANALYSIS.

A. Reliability pricing benefit analysis is conducted using the Reliability Pricing Model software. The Reliability Pricing Model Benefit component of the Benefit/Cost Ratio evaluates the benefits of a proposed economic-based enhancement or expansion that will be realized in the capacity market and is expressed as:

> Reliability Pricing Benefit for Regional Projects = [.50] * [Change in Total System Capacity Cost] + [.50] * [Change in Load Capacity Payment]

Reliability Pricing Benefit for Lower Voltage Projects = [1]*[Change in Load Capacity Payment]

The Change in Total System Capacity Cost is the difference between the sum of the megawatts that are estimated to be cleared in the Base Residual Auction under PJM's Reliability Pricing Model capacity construct multiplied by the prices that are estimated to be contained in the offers for each such cleared megawatt (multiplied by the number of days in the study year) with and without the economic-based enhancement or expansion.

The Change in Load Capacity Payment is the sum of the estimated zonal load megawatts in each PJM transmission zone multiplied by the estimated Final Zonal Capacity Prices (payments paid by load in each transmission zone) for capacity under the Reliability Pricing Model construct (multiplied by the number of days in the study year) minus the value of Capacity Transfer Rights for each PJM transmission zone with and without the economic-based enhancement or expansion. The Change in Load Capacity Payment will be evaluated in the same manner as the Change in Energy Load Payment. Like for the Change in Energy Load Payment, in determining the Change in Load Capacity Payment, only PJM transmission zones that show a decrease will be considered in determining the Change in Load Capacity Payment.

Q. HOW IS THE COST COMPONENT OF THE BENEFIT/COST RATIO CALCULATED?

A. The annual cost of the enhancement is the revenue requirement of the enhancement. The enhancement's annual revenue requirement is an assumption that is developed by PJM and presented to the TEAC for discussion and review. As stated earlier, the benefits and costs will be considered over the same time period (for each of the first 15 years of the life of the expansion).

Q. AFTER APPROVAL, DOES PJM CONTINUE TO EVALUATE MARKET EFFICIENCY PROJECTS?

A. Yes. To assure that projects selected by the PJM Board for market efficiency continue to be economically beneficial, both the costs and benefits of these projects will be reviewed periodically (nominally on an annual basis). Substantive changes in the costs and/or benefits of the approved RTEP projects will be reviewed with the TEAC at a subsequent meeting to determine if these projects continue to provide economic benefits relative to their costs and should remain in the RTEP.

V. <u>SELECTION OF PROPOSED PROJECT</u>

Q. PLEASE DESCRIBE HOW PROJECT 9A WAS IDENTIFIED THROUGH PJM'S MARKET ANALYSIS.

A. As part of the 24-month RTEP cycle ending December 31, 2015, PJM evaluated market efficiency proposals submitted as part of the long-term proposal window opened from October 30, 2014 through February 27, 2015. The window sought technical solution alternatives to certain reliability criteria violations as well as alleviation of certain market efficiency congestion drivers identified in PJM's long-term simulation results.

Q. PLEASE DESCRIBE CONGESTION AS USED IN THIS CONTEXT.

A. Congestion occurs when the least costly resources that are available to serve load in a given region cannot be dispatched because transmission facility limits constrain power flow on the system. This is particularly true in PJM where power often flows from lower-priced generating resources in western zones to load centers in the East. The lowest-priced energy is often constrained from flowing freely to those load centers. When this occurs, PJM's system operator must dispatch higher cost resources to serve load. This results in LMP differences and congestion on the system. The congestion generally increases system production costs, LMPs, and results in increased customer payments for electric energy.

PJM's market efficiency studies look at persistent projected congestion over a 15-year planning horizon in order to identify the potential economic benefit of proposed transmission projects. PJM conducts market simulations which show the extent to which congestion is mitigated under a set of given assumptions including fuel costs, emissions costs, load forecasts, demand resource projections, generation projections and expected future transmission topology.

Q. PLEASE DESCRIBE THE CONGESTION PROBLEM PJM SOUGHT TO ADDRESS THROUGH ITS 2014/15 LONG-TERM PROPOSAL WINDOW.

A. The 2014/15 Long Term Proposal Window solicited proposals to address, among other things, congestion on the AP South Reactive Interface. The AP South Reactive Interface is a set of four 500 kV lines which originate in West Virginia and terminate in Maryland and Virginia. The primary goal of the proposal window was to solicit proposals to reduce congestion on the AP South Reactive Interface, which is one of the most historically congested flowgates in PJM. According to State of the Market Reports by PJM's market monitoring unit, Monitoring Analytics, the congestion cost on the AP South Interface totaled approximately $800 million from 2012 through 2016.

Q. PLEASE FURTHER DESCRIBE THE CONGESTION ASSOCIATED WITH THE REACTIVE INTERFACES, INCLUDING THE AP SOUTH INTERFACE.

A. Voltage or reactive constraints can limit the amount of energy that can be transferred into an area. In operations, PJM establishes limits on the total power flow over lines or combinations of lines to ensure that voltages on the system remain within acceptable levels. These lines or combination of lines that are monitored to ensure voltages on the system remain within acceptable limits are often referred to as a reactive interface. Congestion occurs on these interfaces when more expensive generation must be turned on to control the flow across the lines that make up the reactive interface.

Specifically for the AP South reactive interface, if the sum of the flow on the four 500 kV lines that make up the interface exceeds calculated limits, it can result in low voltages and even potential voltage collapse. In operations, PJM determines the AP South Reactive Interface limits based on system conditions. If the flows across the interface are expected to exceed the established limits, PJM operators will direct higher cost generation in Maryland and Virginia to increase output, while lower cost generation output will be reduced in other parts of PJM to prevent the flows across the interface from exceeding the established limits.

Project 9A reduces congestion on the AP-South reactive interface by providing a parallel path for energy to flow to eastern load centers.

Q. HOW MANY MARKET EFFICIENCY PROJECTS WERE CONSIDERED AND APPROVED IN RESPONSE TO PJM'S 2014/2015 LONG-TERM PROPOSAL WINDOW?

A. There were 93 proposals submitted to address market efficiency needs in the 2014/15 Long-Term Proposal Window. Of those 93 proposals, 41 project proposals were submitted specifically to address congestion on AP South reactive interfaces.

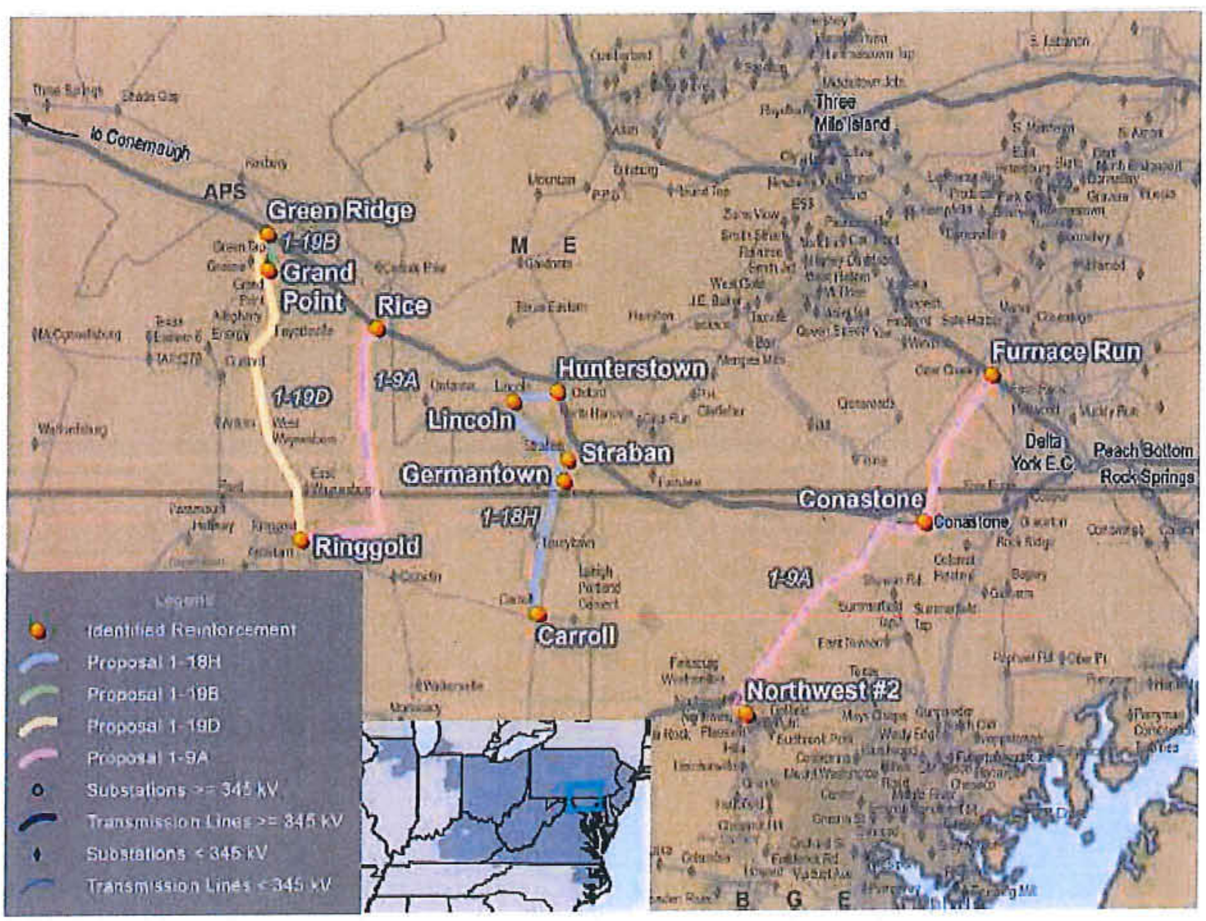
Q. PLEASE EXPLAIN PJM'S ANALYSIS OF THE 41 PROPOSALS SUBMITTED TO RELIEVE CONGESTION ON THE AP-SOUTH REACTIVE INTERFACE.

A. In order to address AP-South interface congestion, PJM assessed transmission solution proposals from among the 41 original proposals submitted to address congestion associated with PJM reactive interfaces over an 18-month period that culminated in the selection of Project 9A in the second quarter of 2016. In February 2016 following PJM staff recommendation, the Board approved several new capacitor banks at existing substations to partially address congestion on the AP South reactive interface. However, even with these upgrades, congestion was expected to persist on the AP South reactive interface. As a result PJM continued to assess the remaining proposals to address the congestion on the AP South interface. The proposals were evaluated as submitted and in combinations. Ultimately, the proposals were reduced to the following four proposal configurations based on the calculated B/C ratio and the degree of congestion relief provided by each proposal:

1. Project 9A, as proposed

2. Projects 18H+9A East
3. Projects 19B+9A East
4. Projects 19D+9A East

Those final four projects, located on the border between Pennsylvania and Maryland, are shown on **Map 1** below. PJM's analyses found Project 9A provided the greatest congestion benefits and highest benefit to B/C Ratio.



Q. DID PJM CONDUCT SENSITIVITY STUDIES PRIOR TO SELECTING THE PROJECT?

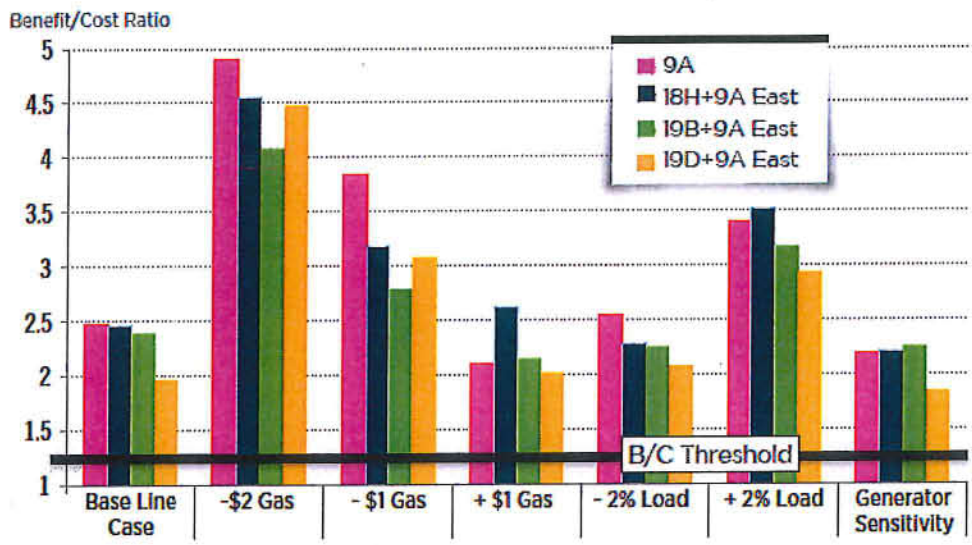
A. Yes. Although Project 9A provided the greatest congestion benefits and highest benefit to B/C Ratio, PJM conducted additional sensitivity analysis comparing Project 9A with three proposal combinations that included the eastern portion of Project 9A under sensitivity variations in load forecast, fuel prices, and generator assumptions:

1. *Baseline Case* – 2015 market efficiency baseline assumptions on gas prices, load, and generation availability
2. *-$2 Gas* – forecasted baseline natural gas price was reduced by $2/MMBtu
3. *-$1 Gas* – forecasted baseline natural gas price was reduced by $1/MMBtu
4. *+$1 Gas* – forecasted baseline natural gas price was increased by $1/MMBtu
5. *-2 Percent* Load – forecasted load was reduced by 2 percent
6. *+2 Percent Load* – forecasted load was increased by 2 percent
7. *Generator Sensitivity (Gen Sens)* – a scenario in which Dickerson and Chalk Point units do not retire.

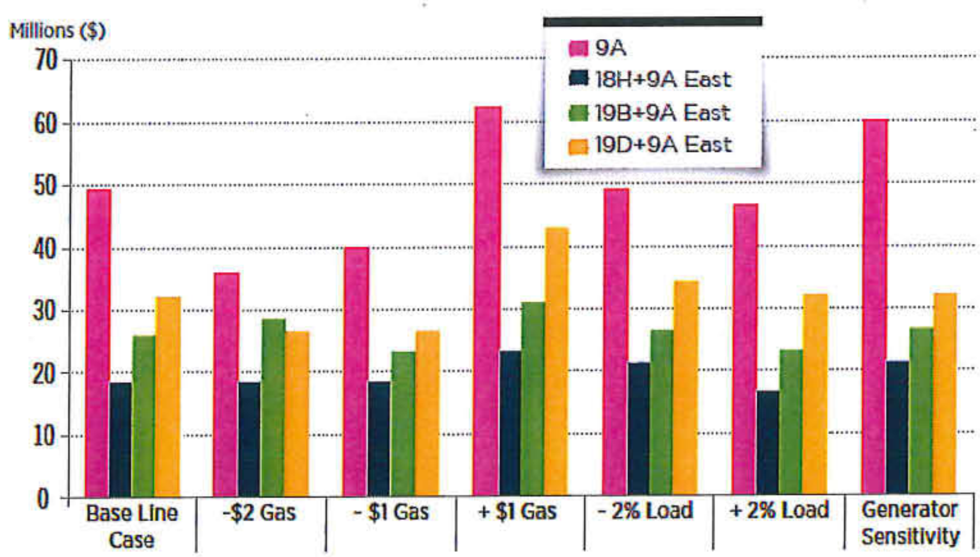
Q. WHAT WERE THE RESULTS OF THESE SCENARIO STUDIES?

A. These scenarios were evaluated in terms of the following project economic benefits, as the successive figures show:

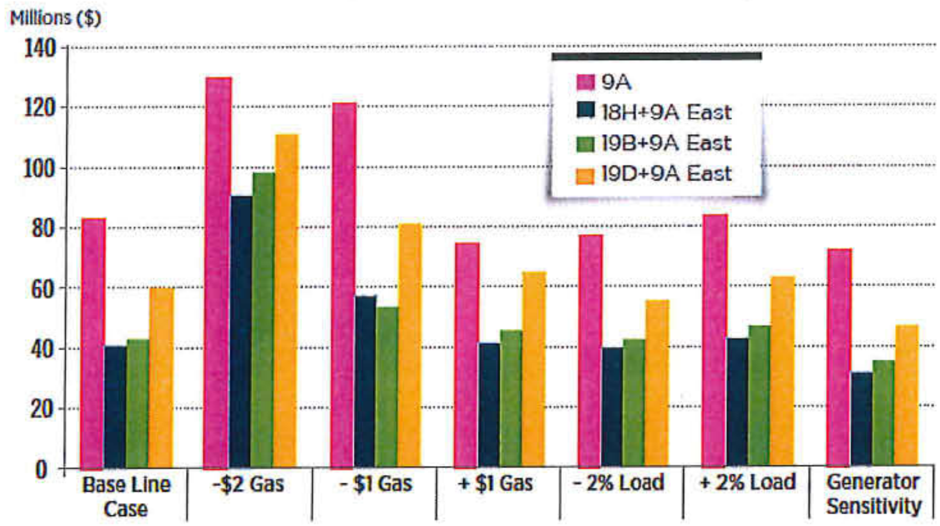
1. Project B/C Ratio under each of the scenario studies is shown in **Figure 1**



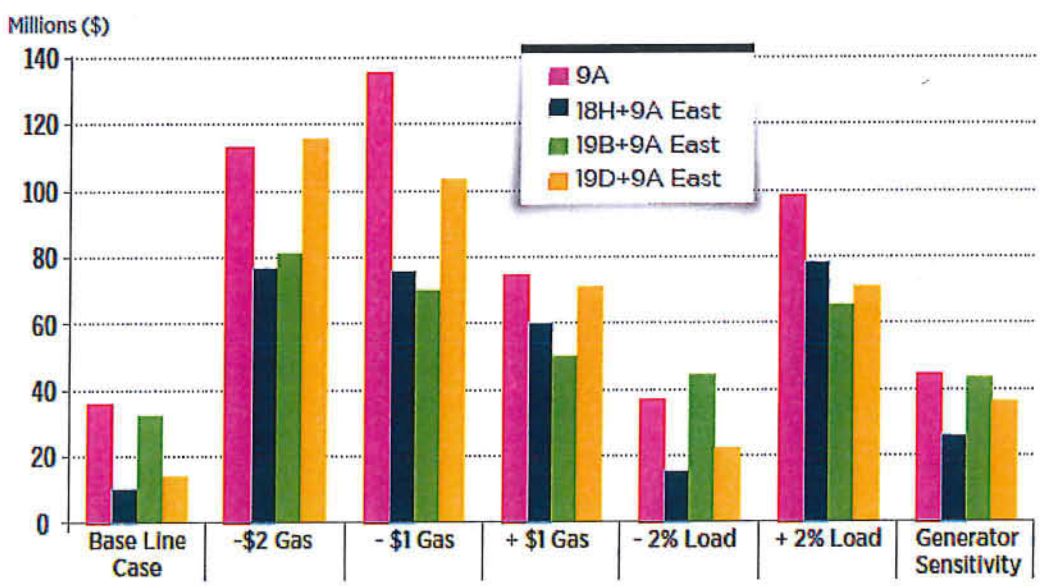
2. The AP-South Congestion Benefit for study years 2019 and 2022 under each of the scenario studies is shown in **Figure 2**



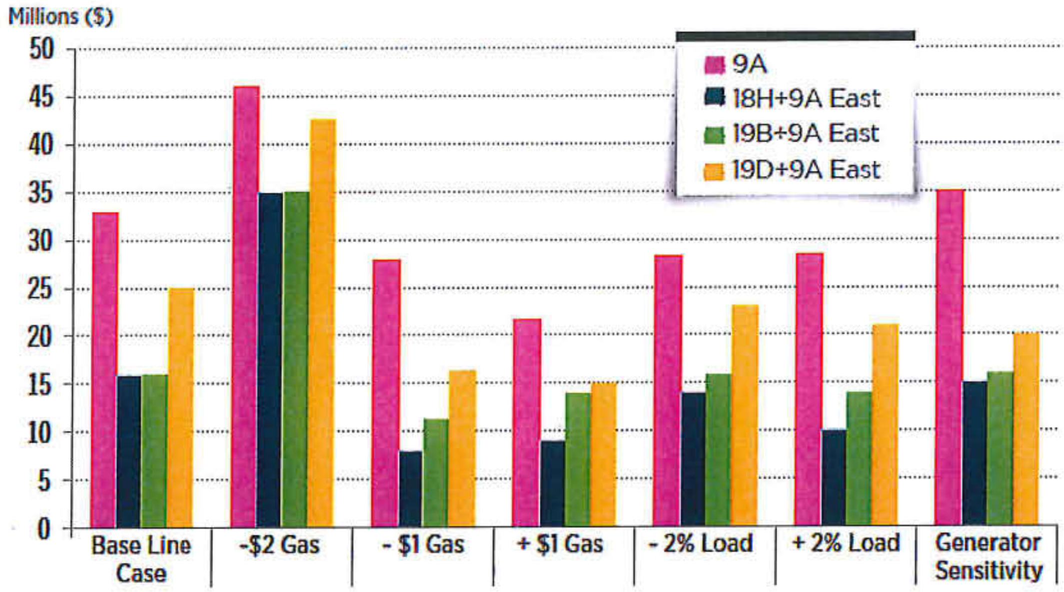
3. PJM Total Congestion Benefits for study years 2019 and 2022 under each of the scenario studies is shown in **Figure 3**



Load Payment Benefits for study years 2019 and 2022 under each of the scenario studies is shown in **Figure 4**



4. PJM Production Cost Benefits for study years 2019 and 2022 under each of the scenario studies is, shown in **Figure 5**



Q. CAN YOU PLEASE SUMMARIZE WHAT THE ABOVE FIGURES DEMONSTRATE?

A. The study results shown in the above figures demonstrate that Project 9A had the highest B/C Ratio, the most significant AP-South congestion benefit, total congestion benefit, load payment benefit and production cost benefit and consistently provided the most benefits across the scenarios studied.

Q. DID PJM CONDUCT ADDITIONAL ANALYSIS WITH PROJECT 9A INCLUDED AS A BASE ASSUMPTION?

A. PJM also conducted additional economic analysis in which Project 9A was added to the base case followed by each of the three other projects in combination with it. Those results indicated that none of the remaining three proposals subsequently passed the B/C 1.25 threshold test.

Q. DID PJM DO AN INDEPENDENT COST ANALYSIS OF PROJECT 9A?

A. Yes. The PJM Operating Agreement at Schedule 6, section 1.5.7(g), requires PJM to develop an independent cost estimate for market efficiency projects with costs in excess of $50 million. PJM engaged an independent consultant who verified the proposed costs, schedule duration, and risks for Project 9A and others, as described in the PJM 2014/2015 Long-Term Proposal Window Independent Cost Review White Paper.[9]

Q. CAN YOU PLEASE BRIEFLY DESCRIBE THE METHODOLOGY USED FOR THAT ANALYSIS?

A. The study analyzed the proposed projects for cost, schedule and constructability. Cost estimates were developed at a conceptual level. Project implementation schedules were generated by identifying the high-level milestones of all major tasks required to complete the project. Timeframes and project sequencing are based on similar projects and are consistent with general industry durations. The constructability review was completed as a high-level desktop analysis utilizing publicly available data.

Q. WHAT WERE THE RESULTS OF THE INDEPENDENT PJM COST ESTIMATE?

A. The independent evaluation verified cost and schedule to be consistent and in general agreement with the proposal as submitted.

[9] Available at: http://www.pjm.com/~/media/committees-groups/committees/teac/20160512/20160512-2014-2015-long-term-proposal-window-independent-cost-review-white-paper.ashx.

Q. WHEN DID PJM APPROVE PROJECT 9A?

A. The project was approved by the PJM Board in August 2016, with an estimated cost of $320.19 million and a required in-service date by June 1, 2020. Expected 15-year congestion and load payment savings are approximately $622 million and $269 million, respectively.

Q. WERE TRANSOURCE AND/OR OTHER PJM TRANSMISSION OWNERS DIRECTED TO CONSTRUCT PROJECT 9A BY A SPECIFIC DATE?

A. Yes. As discussed by Mr. Kamran Ali in his Direct Testimony, after the PJM Board approves a proposed market efficiency project, the successful project bidder (in this case, Transource Energy) is obligated to complete the project once PJM and the successful entity execute a Designated Entity Agreement. On November 2, 2016, PJM and Transource Energy, on behalf of Transource PA and Transource MD, executed a Designated Entity Agreement.

Q. YOU MENTIONED EARLIER THAT AFTER APPROVAL, PJM CONTINUES TO EVALUATE MARKET EFFICIENCY PROJECTS. HAS PJM DONE ANY ADDITIONAL ANALYSIS OF PROJECT 9A SINCE APPROVING IT?

A. Yes. Studies completed in 2017 using updated assumptions showed that Project 9A continued to provide congestion relief, and that Project 9A is expected to provide benefits to customers. Additionally, PJM's analysis of market efficiency projects in the subsequent 2016/2017 Long-Term Proposal Window (i.e., not the proposal window during which Project 9A was evaluated, but the immediately subsequent planning cycle), which is ongoing, takes into consideration the Project 9A facilities as a starting point in the evaluation of further opportunities to relieve transmission congestion in the PJM region.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.