OCA Statement No. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection - East and West Projects in portions of York and Franklin Counties, Pennsylvania.	:	A-2017-2640195 A-2017-2640200
Petition of Transource Pennsylvania, LLC for a finding that a building to shelter control equipment at the Rice Substation in Franklin County, Pennsylvania is reasonably necessary for the convenience or welfare of the public.	:	P-2018-3001878
Petition of Transource Pennsylvania, LLC for a finding that a building to shelter control equipment at the Furnace Run Substation in York County, Pennsylvania is reasonably necessary for the convenience or welfare of the public.	:	P-2018-3001883
Application of Transource Pennsylvania, LLC for approval to acquire a certain portion of the lands of various landowners in York and Franklin Counties, Pennsylvania for the siting and construction of the 230 kV Transmission Line associated with the Independence Energy Connection – East and West Projects as necessary or proper for the service, accommodation, convenience or safety of the public.	:	A-2018-3001881, *et al.*

DIRECT TESTIMONY AND EXHIBITS OF

PETER LANZALOTTA

Filed on Behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

September 25, 2018

DIRECT TESTIMONY OF
PETER J. LANZALOTTA

Q. Please state your name, affiliation and business address.

A. Peter J. Lanzalotta, Lanzalotta & Associates LLC, 67 Royal Pointe Drive, Hilton Head Island SC 29926.

Q. Please describe your educational background.

A. I am a graduate of Rensselaer Polytechnic Institute, where I received a Bachelor of Science degree in Electric Power Engineering. In addition, I hold a Masters degree in Business Administration with a concentration in Finance from Loyola College in Baltimore.

Q. Please describe your professional experience.

A. I am a Principal of Lanzalotta & Associates LLC, which was formed in January 2001. Prior to that, I was a partner of Whitfield Russell Associates, with which I had been associated since March 1982. My areas of expertise include electric utility system planning and operation, electric service reliability, cost of service, and utility rate design. I am a registered professional engineer in the states of Maryland and Connecticut. My prior professional experience is described in Exhibit PJL-1, which is attached hereto.

I have been involved with the planning operation, and analysis of electric utility systems and with utility regulatory matters, including reliability-related matters, certification of new facilities, cost of service, cost allocation, and rate design, as an employee of and as a consultant to a number of privately- and publicly-owned electric utilities, regulatory agencies, developers, and electricity users over a period exceeding thirty years.

I have been involved in a number of projects focused on electric utility transmission and distribution system reliability. I have worked in recent years on behalf of various government offices and agencies in the states of Maryland, New Jersey, and Pennsylvania to help address electric service reliability concerns on behalf of various government offices and agencies in the states of Maryland, New Jersey, Virginia, and other states regarding proposed and/or abandoned electric transmission facilities.

Q. Have you given expert testimony in any judicial or quasi-judicial proceedings?

A. Yes, I have presented expert testimony before the Federal Energy Regulatory Commission and before regulatory commissions and other judicial and legislative bodies in 25 states, the District of Columbia, and the Provinces of Alberta, Ontario, and Nova Scotia. My clients have included utilities, regulatory agencies, ratepayer advocates, independent producers, industrial consumers, the federal government, and various city and state government agencies. The proceedings in which I have testified are listed in Exhibit PJL-2.

Q. What is the purpose of your testimony?

A. My testimony, on behalf of the Pennsylvania Office of Consumer Advocate, is intended to address the need for the transmission facilities proposed by Transource in the IEC Project, the value of such facilities, and technical alternatives to such facilities.

Q. On what information is your testimony based?

A. In preparing my testimony I have reviewed the Company's Application, the initial testimony of Company expert witnesses, the Company's responses to interrogatories in this proceeding, various documents in other transmission line cases in Pennsylvania and Maryland, various PJM and PJM-related documents and information, and other miscellaneous documents.

General Project Information

Q. Please describe the proposed elements of the transmission system additions being proposed by Transource Pennsylvania, LLC ("Transource PA") for approval from the Pennsylvania Public Utility Commission ("Commission").

A. The facilities proposed by Transource PA in this proceeding are part of the Independence Energy Connection Project ("lEC Project") which has been approved by PJM Interconnection, L.L.C. ("PJM") for the purposes of alleviating transmission congestion constraints in Maryland, West Virginia, and Virginia on transmission facilities referred to as the AP South Reactive Interface (“APSRI”).

The IEC Project approved by PJM 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 transmission lines, the Rice-Ringgold 230 kV transmission line (“the IEC West Project Line”) and the Furnace Run-Conastone 230 kV transmission line (“the IEC East Project Line”).

Q. Please summarize your findings.

A. Based on my review, I conclude the following:
The congestion levels on the transmission lines between West Virginia, Maryland and Virginia on the APSRI have been decreasing since the IEC Project was proposed. As addressed in the testimony of Scott Rubin in OCA Statement No.1, the benefit-cost (“B/C”) ratio for the IEC Project has been decreasing since the project was initially evaluated by PJM, and recent evaluations of the B/C ratio, reported by PJM in early 2018, have failed to reflect any complete updates to the project cost, so estimates of B/C ratios are inaccurately high because of such failure. In addition, there are alternatives to elements of the IEC East Project transmission lines as proposed that likely could avoid much or all of the proposed new transmission right-of-way (“ROW”) and new double circuit 230 kV transmission line towers; PJM did not consider these alternatives. There

was also an alternative to the IEC West transmission lines that would not require new transmission line ROW that was considered and rejected by PJM.

<u>Detailed Project Information</u>

Q. Please summarize the project elements that Transource is filing for approval of in this proceeding.

A. As summarized above, The IEC Project approved by PJM 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 transmission lines, the Rice-Ringgold 230 kV transmission line ("the IEC West Project Line") and the Furnace Run-Conastone 230 kV transmission line ("the IEC East Project Line").

The new IEC West Project Line will be sited to extend approximately 28.8 miles, connecting the existing Ringgold Substation located near Smithsburg, Washington County, MD, and the new Rice Substation to be located in Franklin County, PA.

The new IEC East Project Line will be sited to extend approximately 15.8 miles, connecting the existing Conastone Substation located near Norrisville, Harford County, MD, and the new Furnace Run Substation to be located in York County, PA.

Figure 1 below depicts the proposed new substations and the proposed new double circuit 230 kV transmission lines.

Figure 1

Q. Please describe any other facilities that are required in order for the IEC facilities addressed above to be able to function.

A. Baltimore Gas & Electric Company ("BGE") is required to i) construct a new 230 kV breaker and associated equipment, and ii) to reconductor/rebuild two 230 kV transmission lines running from Conastone substation to Northwest substation and upgrade terminal equipment at both substations.

Philadelphia Electric Company ("PECO") is required to construct a tie in to PECO-owned Peach Bottom to Three Mile Island 500 kV line for the Furnace Run substation, and ii) upgraded terminal equipment and relaying on the Peach Bottom to Three Mile Island 500 kV line.

Mid-Atlantic Interstate Transmission LLC ("MAIT") and affiliates are required to i) construct a 500 kV loop connecting the Conemaugh to Hunterstown 500 kV line to the proposed Rice substation, ii) reconfigure the Ringgold substation and replace transformers, and iii) reconductor the 138 kV Ringgold to Catoctin transmission line.

These projects are not part of the Transource applications in this proceeding. However, these ancillary parts of the IEC Project do make up the total cost that PJM is using to calculate its B/C ratio. As such, Witness Scott Rubin addresses the costs of these parts of the IEC Project in his testimony in OCA Statement No. 1.

Q. Please describe the process by which PJM solicited the proposals which led to the IEC Project.

A. PJM manages the annual development of its Regional Transmission Expansion Plan ("RTEP"). As part of this process, PJM seeks technical solution proposals from participants to resolve potential North American Electric Reliability Corporation ("NERC") reliability criteria violations, market efficiency congestion, and other constraints on facilities in accordance with reliability planning and market efficiency criteria. PJM issued its 2014/15 RTEP Long Term Proposal Window Problem Statement ("Problem Statement"), dated October 30, 2014. The Problem Statement provided:

> PJM seeks technical solution alternatives (hereinafter referred to as "Proposals") to resolve potential reliability criteria violations, market efficiency congestion, and Reliability Pricing Model (RPM) constraints on facilities identified below in accordance with planning (PJM, NERC, SERC, RFC, and Local Transmission Owner criteria) and market efficiency criteria.

Transource Energy LLC, together with Dominion High Voltage, submitted a proposal referenced by PJM as Project 9A, one of 93 market efficiency projects proposed by PJM participants and one of 41 proposals directed at congestion on the AP South transmission interface.[1] Exhibit___(PJL-3) lists these 41 proposals, with some detailed evaluation information, as taken from the Transmission Expansion Advisory Committee ("TEAC") documents dated September 10, 2015.

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[1] See TEAC Market Efficiency Update dated August 13, 2015, page 4.

PJM evaluated these proposals based in part on B/C ratios reflecting 15 years of projected loads, projected fuel prices, projected generation mix, projected transmission system capacity, and on various degrees of sensitivity to changes in these system characteristics. Based on these evaluations, PJM chose a group of six finalists from the original 41 proposals. These are shown in Exhibit___(PJL-4). The IEC is listed by the project name "201415_1-9A" by "DOM High Voltage/Transource". The IEC is frequently referred to by PJM as Project 9A.

Note in Exhibit___(PJL-4) that Project 9A is the most expensive of the six finalists. With what was then an estimated cost of $300 million, Project 9A costs more than the other five projects added together. In general, bigger projects can support more congestion relief than a smaller project, as long as they can meet the required B/C ratio hurdle of 1.25.

Q. Please discuss the factors PJM considers when it is evaluating market efficiency projects.

A. As discussed in "Guidelines For Market Efficiency Projects Selection Process"[2]:

> Schedule 6 section 1.5.8 (e) of the PJM Operating Agreement discusses Market Efficiency criteria used in considering the inclusion of Market Efficiency projects in the recommended plan. This document provides 'bright line' primary and 'other' secondary consideration criteria that could be utilized as guidelines in order to facilitate the recommendation process.
>
> 'Bright line' Primary Considerations –
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> 1) Congestion Mitigation: Consistent with the Operating Agreement (OA) Schedule 6 section 1.5.7 (b) (iii) and OA Schedule 6 section 1.5.8 (e), a Market Efficiency proposal will relieve one or more economic constraint(s). If a proposal is submitted to mitigate one congestion driver, then in order to meet this criteria the proposal shall relieve projected congestion on the driver by at least $1. Similarly, if a proposal is submitted to address multiple congestion drivers, then in the order to meet this criteria the proposal shall relieve projected congestion on all the drivers by at least $1. (Economic constraints may be either energy or capacity market congestion. Energy market uplift charges typically born due to local reactive support issues are addressed in the Operational Performance category.)

[2] https://www.pjm.com/-/media/committees-groups/committees/pc/20161103/20161103-item-12b-guidelines-for-market-efficiency-projects-selection-process.ashx

> 2) Benefit/Cost (B/C): Consistent with the OA Schedule 6 section 1.5.7 (d), a Market Efficiency proposal addressing one or more target congestion driver(s) must meet a B/C ratio threshold of at least 1.25:1, calculated over the first 15 years of the life of the proposal. The B/C ratio is calculated using the procedure described in Manual 14B, section 2.6.5. The Market Efficiency Discount Rate and Fixed Carrying Charge Rate are subject to change for any given 24-month Market Efficiency cycle. Therefore, during every cycle, these values are published along with other Market Efficiency input assumptions. Rates published during the 2016/17 cycle are documented in the appendix.
>
> 3) Cost Estimate Review: Consistent with the OA Schedule 6 section 1.5.7 (g), for a Market Efficiency proposal with costs in excess of $50 million, an independent review of such costs will be performed.

The first "bright line primary consideration" mentioned regarding the selection of market efficiency projects is the amount of congestion mitigation. Projects still have to meet the B/C ratio minimum of 1.25, but within that minimum requirement, projects that produce more congestion relief will be preferred to projects that produce less congestion relief. I note that there is nothing in this language that requires PJM to select the project with the highest B/C ratio.

Q. Please discuss the PJM evaluations of proposed projects to address congestion on the AP South transmission interface.

A. In evaluating potential projects, PJM looked at proposals by participants, at combinations of the six proposals listed in Exhibit___(PJL-4), with and without additional capacitors,[3] as well as at other proposal modifications and other proposal combinations. PJM looked at impacts on reliability, congestion, and costs relative to benefits. For the most part, PJM limited its evaluations to submitted proposals and to combinations of projects and project elements that had been proposed by participants.

Q. Does the PJM Analysis you just described match up in any way with the analysis that this Commission must perform when considering an Application for the siting of new transmission facilities?

[3] Capacitors are switchable electric devices that can be installed on transmission lines or substation busses in order to help control the voltage at which the line or bus is operating.

A. No. Commission regulations require that the Commission determine that proposed transmission line(s) will have minimum adverse environmental impact, considering the electric power needs of the public, the state of available technology, and the available alternatives.[4]

The evaluations of market efficiency projects proposed to address congestion on the AP South transmission interface fall short of this determination in several respects. First, neither Transource nor PJM considered minimizing the environmental impacts of new transmission ROW and new transmission towers proposed for the IEC. As discussed later in my testimony, there are two existing available PPL transmission lines on existing rights-of-way, recently completely rebuilt with towers that have the capability of carrying an additional 230 kV circuit in the vicinity of the IEC East Project Line. PJM did not consider trying to use these as part of the IEC, because such use was not included as part of any of the proposals submitted to PJM.[5] Such use could significantly reduce the environmental impact of this portion of the IEC.[6]

In addition, the Commission is required to take the public's need for electric power into consideration when evaluating the environmental impacts of proposed transmission lines. Based on the Company's filed testimony, there is no reliability need for the IEC, which PJM says would address congestion on the transmission system. The following section of my testimony discusses what constitutes a reliability need and why the IEC is meant to address economic concerns and not reliability needs.

No Public Need For the IEC Project

[4] 52 Pa.Code Sec.57.76 (a) (4).

[5] See Exhibit PJL-13 Attached.

[6] Please note the testimony of Witness Scott Rubin (OCA Statement No. 1) where he addresses the possible effects of the Pennsylvania Supreme Court's decision in PEDF and of Act 45 of 2018 on the Commission's determinations regarding proposed transmission lines.

Q. Please address whether the IEC Project is needed for system reliability.

A. Based on the Company's filed testimony, the IEC Project is not required to meet system reliability needs, either at present or in the foreseeable system planning horizon, which for PJM is fifteen years.

Q. Transource witness Ali testified that an additional benefit of this Project was that it would also improve reliability. How do you respond?

A. Any major new piece of transmission line infrastructure will provide additional paths for power to flow, and thus could potentially improve reliability. However, there is no stated reliability need here, based on the Company's filed testimony.

Q. Please describe how electric transmission system planners typically determine that transmission system reinforcements are needed for reliability.

A. The transmission planning criteria formulated by NERC require that the effect of projected future peak loads and the operation of existing and planned generation (less retirements) on existing and planned transmission system facilities, such as transmission lines and substation transformers, be studied to determine if such loads can be reliably served under normal conditions[7] and under prescribed contingency conditions.[8] If the loading of transmission system facilities in these studies under these conditions exceeds the capability of these facilities, or if the transmission system voltage levels fall below or increase above specified levels, this is typically referred to as a NERC violation[9] which is a reliability problem that must then be addressed by the transmission planners.

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[7] Normal conditions assume that all system facilities, such as transmission lines and substation transformers, are in service. Normal conditions can assume various levels of dispatch of existing generating units.

[8] Contingency conditions assume that one or more system facilities, such as transmission lines and substation transformers, are experiencing a forced (unplanned) outage. Contingency conditions can assume various levels of dispatch of existing generating units, including forced outages of generating units.

[9] NERC violations may be referenced as "thermal" which reflect overloaded facilities, or as "voltage" which reflect substation bus voltages that are outside acceptable planning ranges.

Transmission system reinforcement is frequently implemented to maintain required levels of system reliability when NERC transmission planning violations are found by planners. The transmission system reinforcements included in the IEC Project are not required to address any NERC violations and must, therefore, be justified on the basis of economics.

Q. Please discuss why the IEC Project is being proposed if it is not needed to address reliability concerns.

A. The IEC Project is being proposed in order to reduce congestion on PJM's transmission system. Congestion generally refers to loadings of facilities on the transmission system up to their capacities. PJM dispatches generating units in PJM such that generating units with less expensive operating costs are generally loaded up before generating units with higher operating costs are loaded up. If the transmission facilities in some areas are loaded up to their capacity, then sometimes PJM has to increase the dispatch for generating units with higher operating costs that are not dependent on congested transmission lines in order to serve loads without overloading the transmission system. The result of such congestion is typically increased generation costs and increased customer payments for electricity. In the case of the IEC, such congestion does not affect reliability to the extent that it causes a NERC violation that requires a remedy under NERC transmission planning requirements.

Q. Please discuss the congested transmission facilities that the IEC is intended to help address.

A. PJM solicited proposals to address congestion on the AP South Reactive Interface ("APSRI") as part of its 2014/15 Long Term Proposal Window. The APSRI is a set of four 500 kV transmission lines running from West Virginia into Maryland and Virginia. If the sum of the power flows over these four lines exceeds certain calculated limits, then the electric system can be susceptible to low voltages or voltage collapse under certain operating conditions. The power flow across the APSRI must be kept within these limits. Sometimes that means that less expensive-to-operate generating units outside of

Maryland and Virginia will be backed down to generate less power, while more expensive-to-operate generating units inside Maryland and Virginia will be ramped up to generate more power, thus resulting in decreased power flows across the APSRI and increased generation costs for Maryland, DC, and Virginia customers.[10] Transource witness Paul McGlynn references the PJM Independent Market Monitor, which has estimated that congestion costs on the APSRI were about $800 million from 2012 through 2016. The IEC reduces congestion costs on the APSRI by providing an alternative path to load centers in Maryland, DC, and Virginia, connecting them mainly to lower-cost generating units located outside of these areas.

Q. If the IEC helps prevent a potential system voltage collapse, why isn't it considered to be required to meet NERC reliability requirements?

A. The potential for a voltage collapse associated with power flows across the APSRI exists only when such power flows exceed stable limit loadings. If such power flow limits are maintained, such power flows will not cause a voltage collapse. Transource does not know of any such voltage collapses having occurred since 2012.[11] There is no NERC violation and no reliability-based need for more transmission capacity. PJM can limit flows over the APSRI by increasing the operation of generating units in Maryland and Virginia. It is not a NERC violation for PJM to have to operate a less economical mix of generation because of congestion.

As a general matter, the NERC transmission planning reliability regulations define a minimum level of reliability that transmission planners must meet. In doing so, these regulations help prevent excessive levels of planned reliability and the cost of achieving such levels. It is virtually always possible to increase electric system reliability, if cost is no object. But, if a proposed electric transmission reinforcement exceeds NERC required minimum levels of planning reliability, then such a project is considered to be a market

[10] There are only a limited number of generators located in DC.

[11] See the Response to OCA Set I, request no. 18 (e), which is included as Exhibit___(PJL-11).

efficiency project. As such, the cost of such reinforcement needs to be justified by lowering electric system operating costs enough to pay the costs of building and maintaining the reinforcement, according to PJM criteria.

Evaluating Project Economics

Q. Please discuss how PJM evaluated the economics of proposals it received to address congestion on the APSRI.

A. PJM evaluated these proposals based in part on the calculation of B/C ratios reflecting 15 years of projected loads, projected fuel prices, projected generation mix, projected transmission system capacity, and on various degrees of sensitivity to changes in these system characteristics.

Q. Please discuss some of the issues with PJM's evaluation of market efficiency projects.

A. This critique is in addition to the evaluation of PJM's evaluation of market efficiency projects discussed in the testimony of Scott Rubin in OCA Statement No. 1.

PJM's evaluation of market efficiency projects requires accurate forecasts of loads, in-service generation, in-service transmission facilities, fuel costs, and other factors for 15 years into the future. This task is made even more difficult by the volatile nature of relevant system parameters in recent years.

One of the major shortcomings of PJM's process of determining the B/C ratios of the IEC Project is that the costs of the project elements have not been updated since the project was initially evaluated in 2015. Additional project elements have been added as the need for them has become apparent, but the costs of the new substations and new 230 kV double circuit transmission lines have not been updated. Table 1 below, shows the change in the Handy Whitman Index for total transmission costs from January 2015 through January 2018. Exhibit___(PJL-10) contains an excerpt from the Handy Whitman Index regarding transmission construction costs. [12]

Table 1

Escalation of Typical Total Transmission Costs			
Year	Month	Index	Increase %
2015	Jan	722	
2018	Jan	778	7.76%
Based on Handy Whitman Index - North Atlantic Region			

Since 2015, the costs of new typical transmission facilities as reported in the Handy Whitman Index has increased by 7.76% through January 1, 2018. Obviously, if the costs of the proposed facilities have increased since the Projects were evaluated by PJM, then the B/C ratios produced by PJM are not representative of the economic value of the projects.

Another concern, for example, is that PJM peak summer load levels have been decreasing, and the load growth that was projected for when the IEC would go into service have been significantly reduced. While PJM uses its load forecasts in its evaluation of market efficiency projects, the fact that its load forecasts are continually declining means that PJM's market efficiency project evaluations are based on future peak load forecasts that are overstated.

Table 2 below shows actual summer peak loads for BGE, for Pepco, and For Dominion for 2014 and 2017, as well as peak load forecasts for the year 2020 from the PJM 2015 Forecast and the PJM 2018 Forecast, where 2020 is the proposed in-service date for the IEC.[13]

[12] The Handy Whitman Index is a widely-recognized index of utility construction costs over time.

[13] Summer peak loads are used here because PJM is summer peaking, because the level of loads on days other than the day of the annual peak can decrease when the load on the day of the annual peak decreases, and because the load

Table 2

	Actual and Forecast Peak Loads (MW)			
	Actual Summer Peak		Forecast 2020 Peak	
	2014	2017	2015 Forecast	2018 Forecast
BGE	6,666	6,449	7,457	6,753
Pepco	6,346	6,098	6,853	6,405
DOM	18,761	18,903	22,068	19,858
Total	31,773	31,450	36,378	33,016

When the proposal for the IEC was submitted in 2015, the most recent summer peaks for BGE, Pepco, and Dominion were from 2014 and totaled 31,773 MW, as shown in Table 2. By 2017, these peak loads had decreased to 31,450 MW. These three companies represent the bulk of the loads in Maryland, DC and Virginia.[14] The 2015 forecast of the projected summer peak loads for 2020 was 36,378 MW for these three companies. This was the peak load expected for the year in which the IEC would go into service. The 2018 forecast of the 2020 peak load for the three companies, at 33,016 MW, has dropped by more than 3,300 MW in the past three years. Such a continuing decrease in forecasted loads is likely to affect the level of congestion on transmission facilities and is likely to lower the value of reducing such congestion.

Summer peak loads and peak load forecasts have been declining across PJM's Mid-Atlantic area for at least the past five years or more. This area includes loads in New Jersey, Maryland, Delaware, DC, and Pennsylvania, some of which are loads that contribute to the projected loads on the IEC Project transmission lines.

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carrying capacity of transmission lines is frequently lower in summer than in winter when cooler ambient temperatures frequently allow increased loading.

[14] As described in McGlynn's Direct Testimony, the AP South Interface is a set of four 500 kV transmission lines which run from West Virginia to Maryland and Virginia. See pp.24, lines 19-21. As such, the loading on the lines of the APSRI can be affected by the level of loads in Maryland, Virginia, and the District of Columbia.

Exhibit___(PJL-6) shows actual summer peak loads from 2012 through 2017 on line 12, and PJM forecast summer peak loads on lines 4 through 10 for PJM's Mid-Atlantic area. Note that actual peak loads for the Mid-Atlantic have decreased from 60,037 MW in 2012 down to 55,220 in 2017. During this time, the forecast peak load for 2020 (IEP's projected in-service date) has decreased from 66,408 MW in the 2012 PJM Forecast down to 56,283 MW in the 2018 PJM Forecast. Note also that the 2018 PJM Forecast is projecting further declines in summer peak load for the Mid-Atlantic area for the years 2019, 2020, and 2021 (see line 10 on Exhibit___(PJL-6)).

Q. Please discuss any other areas of volatility that are of concern.

A. Another area of volatility is congestion costs. Witness McGlynn reports $800 million of congestion costs on the AP South Interface from 2012 through 2016 in his direct testimony.

Table 3 below summarizes PJM's annual congestion costs due to congestion on the AP South Interface, the percentage of total PJM congestion represented by such costs, and the annual total of congestion costs on the PJM system from 2014 through the first half of 2018.

Table 3

PJM Annual Congestion Costs ($M)			
Year	AP South Interface	% of PJM	Total PJM
2014	$486.8	25.20%	$1,932
2015	$56.2	4.10%	$1,371
2016	$16.8	1.60%	$1,050
2017	$21.6	3.10%	$697
2018 1st 6 mo	$17.6	2.00%	$880

As Table 3 shows, the annual congestion costs due to the AP South Interface have been sharply declining since 2014 both in absolute terms and as a percentage of PJM total congestion costs. The 2017 annual congestion cost due to the AP South Interface has decreased by more than 95% from 2014. Table 3 also shows the total decline in PJM congestion costs since 2014. For 2014, total PJM congestion is $1.98 billion. For 2017, total PJM congestion has decreased to $697 million. This means that total congestion on PJM's transmission system has decreased by more than 60% over the past three years.

Q. What do you conclude from this current data on the need to address congestion on the APSRI?

A. I conclude that the original need for this Project was based on economic conditions that simply no longer exist. With these economic conditions changing so rapidly, it is difficult for PJM to keep its forward looking models accurately reflecting projected future conditions.

Q. Please discuss any national studies regarding transmission system congestion.

A. The U. S. Department of Energy has conducted an ongoing study of electric transmission congestion. The most recent report addressing this study was in September 2015 ("2015 Study"). The summary section of this report stated:

> Recent Nation-Wide Trends Affecting Transmission Constraints and Congestion since the 2009 Congestion Study
>
> Transmission constraints and congestion are influenced by both broad, economy-wide trends or conditions, and unique regional and sometimes local circumstances. The Department found that several broad, nation-wide trends have affected transmission usage patterns since the publication of the 2009 Congestion Study. In most areas, the net effect of these trends has been a reduction in the incidence of congestion and its economic costs.[15]

Among the trends referenced in the 2015 Study are i) reduced electric demand from the 2008-2009 economic recession, ii) government policies supporting improvements in electric efficiency, iii) sustained investments in transmission facilities, and iv) state renewable portfolio standards.

[15] National Electric Transmission Congestion Study, September 2015, pp. xv.

An excerpt from the 2015 Study is included as Exhibit___(PJL-7).

Q. Please address changes to electric markets that are currently being considered and how they might affect transmission congestion costs 15 years into the future.

A. The U. S. DOE has been ordered to consider changes to electric power markets that have the goal of increasing the financial attractiveness to owners of base-load coal and nuclear generating units of keeping such units in service. Exhibit___(PJL-8) is an article from the New York Times that describes presidential orders to DOE to prepare steps to stop the closing of coal and nuclear plants around the country. Such an initiative could change i) the number of coal plants expected to be in service in the future, ii) how those units are dispatched and iii) what the generation from those plants will cost over the next 15 years. Such changes could significantly affect the results of the studies being run by PJM to estimate the effects of Project 9A on power costs and system congestion for 15 years into the future.

Q. The generation mix in PJM in is a state of flux, with announcements of plans to increase the amount of renewable generation to be installed and plans to accelerate generator unit retirements. Please address how such changes can affect estimates of transmission system congestion or congestion costs 15 years into the future.

A. In recent months, there have been proposals of new renewable resource generating units proposed to be located in Maryland and Virginia on the load-side of the APSRI. On July 24, 2018, Dominion Energy announced new plans to add 3,000 MW of new solar and wind generation during the 2020s. The Dominion announcement also referenced plans to add 240 MW of solar generation to be located in Virginia. Included as Exhibit___(PJL-9) is the Transource Response to OCA Set XXIII request no. 2 which included the full text of the Dominion press release. There is no indication that the effects of any of these recent proposals, which could reduce the amount of load in Maryland and Virginia potentially being served over the APSRI,[16] have been reflected in PJM evaluations of the IEC Project.

Transmission Alternatives

Q. The proposed IEC includes new transmission right-of-way (“ROW”) for both of its proposed double circuit 230 kV transmission lines. Please discuss any existing transmission alternatives to these new ROWs.

A. If we assume that there is a need for the IEC, there are viable alternatives to both of the proposed new ROWs. These are important because transmission planners typically try to avoid greenfield construction of overhead transmission lines because of their significant effects on communities and landowners. Based on my own observations on site visits in Franklin and York counties and on public input hearing testimony, that is certainly the case for these proposed new transmission lines, much of which will located in new ROW which will be crossing preserved farmland.

Regarding the IEC – East Project which proposes a double circuit 230 kV transmission line to run from Furnace Run substation in York County to the Conastone substation in Maryland, there are two recently-rebuilt PPL 230 kV transmission lines, each of which carries one 230 kV circuit and each of which has the capacity to carry another new 230 kV circuit, that are both in the vicinity of the route of the proposed Furnace Run to Conastone transmission line.[17] One of the newly rebuilt 230 kV lines runs from Otter Creek substation in Pennsylvania to Conastone substation, while the other newly rebuilt 230 kV line runs from Manor substation in Pennsylvania to the Graceton substation in Maryland, which is located to the east of Conastone and is interconnected by a 230 kV transmission line. Both of these newly rebuilt 230 kV transmission lines are designed to carry two circuits, but since each carries only one circuit, each can accommodate the

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[16] See Exhibit___(PJL- 9) Response to OCA Set XXIII, request no. 2.

[17] See PPL responses to OCA Set XII, nos. 1, 2, 3, 6, 8, 9, 10, and 13, all of which are attached in Exhibit___(PJL-12)

addition of a new circuit. Adding a new 230 kV circuit to each of these PPL tower lines would duplicate to a great extent the two proposed new 230 kV circuits of the IEC – East Project without the need for about 16 miles of new ROW. There may be some additional facilities needed in addition to these two new circuits, one from Otter Creek to Conastone and one from Manor to Graceton, in order to provide the capabilities of the proposed Furnace Run to Conastone double circuit. One such instance is the need to address a 1.1 mile section of the PPL Manor to Graceton tower line where it crosses the Susquehanna River that has capacity only for its existing circuit. However, using these existing PPL transmission line towers to each carry an additional 230 kV circuit would eliminate the need, if any at all, for the expense, and the detrimental environmental impacts of about 16 miles of new ROW and new transmission towers.

Q. Please discuss why PJM chose a proposal which requires new transmission towers and a new transmission ROW over one that makes use of existing towers and existing ROW.

A. PJM did not evaluate the use of the existing PPL transmission towers and existing ROWs because such use was not part of a proposal submitted to PJM as part of their solicitation process.[18] PJM does not maintain an inventory of transmission lines that have been built or rebuilt as double circuit lines yet which currently have only one set of conductors.[19]

Q. Please discuss any transmission alternatives considered to the new transmission ROW from the Rice substation in PA to the Ringgold substation in MD and the new double circuit 230 kV towers proposed by Transource for the IEC-West Project

A. PJM evaluated a modified version of Proposal 18H submitted by MAIT, which was a proposal to upgrade existing facilities, together with 9A East.[20] PJM's evaluation of 18H plus 9A East shows that it has either the 1st or second highest B/C ratio of all four

[18] See response to OCA Set XI, request no 7 which is included as Exhibit___(PJL-13)

[19] See response to OCA Set XVII, request no 1 (c) which is included as Exhibit___(PJL-14)

[20] See response to OCA Set XVII, request no. 1 and McGlynn's Direct Testimony, pp. 26 – 31.

alternatives it is evaluating among the seven different sensitivity scenarios shown in Mr. McGlynn's testimony. While it shows that the 18H plus 9A has lower congestion benefits and load payment benefits than the other three alternatives, this reflects a relatively low implementation cost and limited scope for the project that is implicit with the high B/C ratio for 18H plus 9A East.

While 18H plus 9A East may produce smaller benefits, it is an alternative to 9A West reflecting an upgrade of existing facilities, eliminating the need for 29 miles of new ROW and new transmission towers. PJM assigns no value to the environmental benefits of avoiding the impacts of 29 miles of new ROW and new overhead transmission lines. PJM focuses on the size of the B/C ratio and on the size of the benefits. But, in consideration of the greatly reduced impacts of available alternatives to elements of the IEC, such as 18H plus 9A, I recommend that the Commission deny approval for the IEC Project as proposed.

Q. What do you recommend?

A. It is clear from the Company's filed testimony that this portion of the project is not needed to maintain reliability. It is not clear that, given the reduced congestion and reduced peak loads in PJM and given the failure to consider up-to-date costs that the proposed facilities are an optimal way of addressing congestion, if it should be addressed at all. Commission regulations require that the Commission determine that proposed transmission line(s) will have minimum adverse environmental impact, considering the electric power needs of the public, the state of available technology and the available alternatives.[21] This is an instance where there are what could be viable alternatives to the Company's proposals that were not considered by PJM. It is difficult to perceive how the Commission could determine that the proposed transmission line for the IEC East Project would have minimum environmental impacts.

Q. Does this conclude your testimony?

[21] 52 Pa.Code Sec. 57.76 (a) (4).

A.	Yes, at this time.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Application of Transource Pennsylvania, LLC for approval of the Siting and Construction of the 230 kV Transmission Line Associated with the Independence Energy Connection - East and West Projects in portions of York and Franklin Counties, Pennsylvania.	:	A-2017-2640195 A-2017-2640200
Petition of Transource Pennsylvania, LLC for a finding that a building to shelter control equipment at the Rice Substation in Franklin County, Pennsylvania is reasonably necessary for the convenience or welfare of the public.	:	P-2018-3001878
Petition of Transource Pennsylvania, LLC for a finding that a building to shelter control equipment at the Furnace Run Substation in York County, Pennsylvania is reasonably necessary for the convenience or welfare of the public.	:	P-2018-3001883
Application of Transource Pennsylvania, LLC for approval to acquire a certain portion of the lands of various landowners in York and Franklin Counties, Pennsylvania for the siting and construction of the 230 kV Transmission Line associated with the Independence Energy Connection – East and West Projects as necessary or proper for the service, accommodation, convenience or safety of the public.	:	A-2018-3001881, *et al.*

VERIFICATION

I, Peter Lanzalotta, hereby state that the facts above set forth in my Direct Testimony OCA Statement No. 2 are true and correct and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

Signature: ______________________

Peter J. Lanzalotta
Lanzalotta & Associates LLC
67 Royal Pointe Drive
Moss Creek Plantation
Hilton Head Island, SC. 29926
petelanz@lanzalotta.com

DATED: September 25, 2018
*259204

Exhibit___(PJL-1)
OCA Statement No. 2

Prior Experience Of Peter J. Lanzalotta

Mr. Lanzalotta has more than thirty-five years experience in electric utility system planning, power pool operations, distribution operations, electric service reliability, load and price forecasting, and market analysis and development. Mr. Lanzalotta has appeared as an expert witness on utility reliability, planning, operation, and rate matters in more than 130 proceedings in 25 states, the District of Columbia, the Provinces of Alberta, Nova Scotia, and Ontario, before the Federal Energy Regulatory Commission, and before U. S. District Court. He has developed evaluations of electric utility system cost, system value, reliability planning, transmission and distribution maintenance practices, and reliability of service.

Prior to his forming Lanzalotta & Associates LLC in 2001, he was a Partner at Whitfield Russell Associates in Washington DC for fifteen years and a Senior Associate for approximately four years before that. He holds a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute and a Master of Business Administration with a concentration in Finance from Loyola College of Baltimore.

Prior to joining Whitfield Russell Associates in 1982, Mr. Lanzalotta was employed by the Connecticut Municipal Electric Energy Cooperative ("CMEEC") as a System Engineer. He was responsible for providing operational, financial, and rate expertise to Coop's budgeting, ratemaking and system planning processes. He participated on behalf of CMEEC in the Hydro-Quebec/New England Power Pool Interconnection project and initiated the development of a database to support CMEEC's pool billing and financial data needs.

Prior to his CMEEC employment, he served as Chief Engineer at the South Norwalk (Connecticut) Electric Works, with responsibility for planning, data processing, engineering, rates and tariffs, generation and bulk power sales, and distribution operations. While at South Norwalk, he conceived and implemented, through Northeast Utilities and NEPOOL, a peak-shaving plan for South Norwalk and a neighboring municipal electric utility, which resulted in substantial power supply savings. He programmed and implemented a computer system to perform customer billing and maintain accounts receivable accounting. He also helped manage a generating station overhaul and the undergrounding of the distribution system in South Norwalk's downtown.

From 1977 to 1979, Mr. Lanzalotta worked as a public utility consultant for Van Scoyoc & Wiskup and separately for Whitman Requart & Associates in a variety of positions. During this time, he developed cost of service, rate base evaluation, and rate design impact data to support direct testimony and exhibits in a variety of utility proceedings, including utility price squeeze cases, gas pipeline rates, and wholesale electric rate cases.

Prior to that, He worked for approximately 2 years as a Service Tariffs Analyst for the Finance Division of the Baltimore Gas & Electric Company where he developed cost and revenue studies, evaluated alternative rate structures, and studied the rate structures of other utilities for a variety of applications. He was also employed by BG&E in Electric System Operations for approximately 3 years, where his duties included operations analysis, outage reporting, and participation in the development of BG&E's first computerized customer information and service order system.

Mr. Lanzalotta is a member of the Institute of Electrical & Electronic Engineers, the Association of Energy Engineers, the National Fire Protection Association, and the American Solar Energy Society. He is also registered Professional Engineer in the states of Maryland and Connecticut.

Exhibit___(PJL-2)
OCA Statement No. 2

Proceedings In Which
Peter J. Lanzalotta
Has Testified

1. **In re: Public Service Company of New Mexico**, Docket Nos. ER78-337 and ER78-338 before the Federal Energy Regulatory Commission, concerning the need for access to calculation methodology underlying filing.

2. **In re: Baltimore Gas and Electric Company**, Case No. 7238-V before the Maryland Public Service Commission, concerning outage replacement power costs.

3. **In re: Houston Lighting & Power Company**, Texas Public Utilities Commission Docket No. 4712, concerning modeling methods to determine rates to be paid to cogenerators and small power producers.

4. **In re: Nevada Power Company**, Nevada Public Service Commission, Docket No. 83-707 concerning rate case fuel inventories, rate base items, and O&M expense.

5. **In re: Virginia Electric & Power Company**, Virginia State Corporation Commission, Case No. PUE820091, concerning the operating and reliability-based need for additional transmission facilities.

6. **In re: Public Service Electric & Gas Company**, New Jersey Board of Public Utilities, Docket No. 831-25, concerning outage replacement power costs.

7. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. P-830453, concerning outage replacement power costs.

8. **In re: Cincinnati Gas & Electric Company**, Public Utilities Commission of Ohio, Case No. 83-33-EL-EFC, concerning the results of an operations/fuel-use audit conducted by Mr. Lanzalotta.

9. **In re: Kansas City Power and Light Company**, before the State Corporation Commission of the state of Kansas, Docket Nos. 142,099-U and 120,924-U, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

10. **In re: Philadelphia Electric Company**, Pennsylvania Public Utilities Commission, Docket No. R-850152, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

11. **In re: ABC Method Proposed for Application to Public Service Company of Colorado**, before the Public Utilities Commission of the State of Colorado, on behalf of the Federal Executive Agencies ("FEA"), concerning a production cost allocation methodology proposed for use in Colorado.

12. **In re: Duquesne Light Company**, Docket No. R-870651, before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning the system reserve margin needed for reliable service.

13. **In re: Pennsylvania Power Company**, Docket No. I-7970318 before the Pennsylvania Public Utilities Commission, on behalf of the Office of Consumer Advocate, concerning outage replacement power costs.

14. **In re: Commonwealth Edison Company**, Docket No. 87-0427 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from new base-load generating facilities, needed for reliable system operation.

15. **In re: Central Illinois Public Service Company**, Docket No. 88-0031 before the Illinois Commerce Commission, on behalf of the Citizen's Utility Board of Illinois, concerning the degree to which existing generating capacity is needed for reliable and/or economic system operation.

16. **In re: Illinois Power Company**, Docket No. 87-0695 before the State of Illinois Commerce Commission, on behalf of Citizens Utility Board of Illinois, Governors Office of Consumer Services, Office of Public Counsel and Small Business Utility Advocate, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation, and the capacity available from existing generating units.

Proceedings In Which
Peter J. Lanzalotta
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17. **In re: Florida Power Corporation**, Docket No. 860001-EI-G (Phase II), before the Florida Public Service Commission, on behalf of the Federal Executive Agencies of the United States, concerning an investigation into fuel supply relationships of Florida Power Corporation.

18. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Docket No. 877, on behalf of the Public Service Commission Staff, concerning the need for and availability of new generating facilities.

19. **In re: South Carolina Electric & Gas Company**, before the South Carolina Public Service Commission, Docket No. 88-681-E, On Behalf of the State of Carolina Department of Consumer Affairs, concerning the capacity needed for reliable system operation, the capacity available from existing generating units, relative jurisdictional rate of return, reconnection charges, and the provision of supplementary, backup, and maintenance services for QFs.

20. **In re: Commonwealth Edison Company**, Illinois Commerce Commission, Docket Nos. 87-0169, 87-0427, 88-0189, 88-0219, and 88-0253, on behalf of the Citizen's Utility Board of Illinois, concerning the determination of the capacity, from a new base-load generating facility, needed for reliable system operation.

21. **In re: Illinois Power Company**, Illinois Commerce Commission, Docket No. 89-0276, on behalf of the Citizen's Utility Board Of Illinois, concerning the determination of capacity available from existing generating units.

22. **In re: Jersey Central Power & Light Company**, New Jersey Board of Public Utilities, Docket No. EE88-121293, on behalf of the State of New Jersey Department of the Public Advocate, concerning evaluation of transmission planning.

23. **In re: Canal Electric Company**, before the Federal Energy Regulatory Commission, Docket No. ER90-245-000, on behalf of the Municipal Light Department of the Town of Belmont, Massachusetts, concerning the reasonableness of Seabrook Unit No. 1 Operating and Maintenance expense.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

24. **In re: New Hampshire Electric Cooperative Rate Plan Proposal**, before the New Hampshire Public Utilities Commission, Docket No. DR90-078, on behalf of the New Hampshire Electric Cooperative, concerning contract valuation.

25. **In re: Connecticut Light & Power Company**, before the Connecticut Department of Public Utility Control, Docket No. 90-04-14, on behalf of a group of Qualifying Facilities concerning O&M expenses payable by the QFs.

26. **In re: Duke Power Company**, before the South Carolina Public Service Commission, Docket No. 91-216-E, on behalf of the State of South Carolina Department of Consumer Advocate, concerning System Planning, Rate Design and Nuclear Decommissioning Fund issues.

27. **In re: Jersey Central Power & Light Company**, before the Federal Energy Regulatory Commission, Docket No. ER91-480-000, on behalf of the Boroughs of Butler, Madison, Lavallette, Pemberton and Seaside Heights, concerning the appropriateness of a separate rate class for a large wholesale customer.

28. **In re: Potomac Electric Power Company**, before the Public Service Commission of the District of Columbia, Formal Case No. 912, on behalf of the Staff of the Public Service Commission of the District of Columbia, concerning the Application of PEPCO for an increase in retail rates for the sale of electric energy.

29. **Commonwealth of Pennsylvania, House of Representatives**, General Assembly House Bill No. 2273. Oral testimony before the Committee on Conservation, concerning proposed Electromagnetic Field Exposure Avoidance Act.

30. **In re: Hearings on the 1990 Ontario Hydro Demand\Supply Plan**, before the Ontario Environmental Assessment Board, concerning Ontario Hydro's System Reliability Planning and Transmission Planning.

Proceedings In Which
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Has Testified

31. **In re: Maui Electric Company**, Docket No. 7000, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning MECO's generation system, fuel and purchased power expense, depreciation, plant additions and retirements, contributions and advances.

32. **In re: Hawaiian Electric Company, Inc.**, Docket No. 7256, before the Public Utilities Commission of the State of Hawaii, on behalf of the Division of Consumer Advocacy, concerning need for, design of, and routing of proposed transmission facilities.

33. **In re: Commonwealth Edison Company**, Docket No. 94-0065 before the Illinois Commerce Commission on behalf of the City of Chicago, concerning the capacity needed for system reliability.

34. **In re: Commonwealth Edison Company**, Docket No. 93-0216 before the Illinois Commerce Commission on behalf of the Citizens for Responsible Electric Power, concerning the need for proposed 138 kV transmission and substation facilities.

35. **In re: Commonwealth Edison Company**, Docket No. 92-0221 before the Illinois Commerce Commission on behalf of the Friends of Illinois Prairie Path, concerning the need for proposed 138 kV transmission and substation facilities.

36. **In re: Commonwealth Edison Company**, Docket No. 94-0179 before the Illinois Commerce Commission on behalf of the Friends of Sugar Ridge, concerning the need for proposed 138 kV transmission and substation facilities.

37. **In re: Public Service Company of Colorado**, Docket Nos. 95A-531EG and 95I-464E before the Colorado Public Utilities Commission on behalf of the Office of Consumer Counsel, concerning a proposed merger with Southwestern Public Service Company and a proposed performance-based rate-making plan.

Proceedings In Which
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Has Testified

38. **In re: South Carolina Electric & Gas Company, Duke Power Company, and Carolina Power & Light Company**, Docket No. 95-1192-E, before the South Carolina Public Service Commission on behalf of the South Carolina Department of Consumer Advocate, concerning avoided cost rates payable to qualifying facilities.

39. **In re: Lawrence A. Baker v. Truckee Donner Public Utility District**, Case No. 55899, before the Superior Court of the State of California on behalf of Truckee Donner Public Utility District, concerning the reasonableness of electric rates.

40. **In re: Black Hills Power & Light Company**, Docket No. OA96-75-000, before the Federal Energy Regulatory Commission on behalf of the City of Gillette, Wyoming, concerning the Black Hills' proposed open access transmission tariff.

41. **In re: Metropolitan Edison Company and Pennsylvania Electric Company** for Approvals of the Restructuring Plan Under Section 2806, Docket Nos. R-00974008 and R-00974009 before the Pennsylvania PUC on behalf of Operating NUG Group, concerning miscellaneous restructuring issues.

42. **In re: New Jersey State Restructuring Proceeding** for consideration of proposals for retail competition under BPU Docket Nos. EX94120585U; E097070457; E097070460; E097070463; E097070466 before the New Jersey BPU on behalf of the New Jersey Division of Ratepayer Advocate, concerning load balancing, third party settlements, and market power.

43. **In re: Arbitration Proceeding In City of Chicago v. Commonwealth Edison** for consideration of claims that franchise agreement has been breached, Proceeding No. 51Y-114-350-96 before an arbitration panel board on behalf of the City of Chicago concerning electric system reliability.

44. **In re: Transalta Utilities Corporation**, Application No. RE 95081 on behalf of the ACD companies, before the Alberta Energy And Utilities Board in reference to the use and value of interruptible capacity.

Proceedings In Which
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Has Testified

45. **In re: Consolidated Edison Company,** Docket No. EL99-58-000 on behalf of The Village of Freeport, New York, before FERC in reference to remedies for a breach of contract to provide firm transmission service on a non-discriminatory basis.

46. **In re: ESBI Alberta Ltd.,** Application No. 990005 on behalf of the FIRM Customers, before the Alberta Energy And Utilities Board concerning the reasonableness of the cost of service plus management fee proposed for 1999 and 2000 by the transmission administrator.

47. **In re: South Carolina Electric & Gas Company,** Docket No. 2000-0170-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new and repowered generating units at the Urquhart generating station.

48. **In re: BGE,** Case No. 8837 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

49. **In re: PEPCO,** Case No. 8844 on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning proposed electric line extension charges.

50. **In re: GenPower Anderson LLC,** Docket No. 2001-78-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the GenPower Anderson LLC generating station.

51. **In re: Pike County Light & Power Company,** Docket No. P-00011872, on behalf of Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Pike County request for a retail rate cap exception.

Proceedings In Which
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Has Testified

52. **In re: Potomac Electric Power Company and Conectiv,** Case No. 8890, on behalf of the Maryland Office of People's Counsel before the Maryland Public Service Commission concerning the proposed merger of Potomac Electric Power Company and Conectiv.

53. **In re: South Carolina Electric & Gas Company,** Docket No. 2001-420-E on behalf of the South Carolina Department of Consumer Affairs before the Public Service Commission of South Carolina concerning an application for a Certificate of Environmental Compatibility and Public Convenience and Necessity for new generating units at the Jasper County generating station.

54. **In re: Connecticut Light & Power Company,** Docket No. 217 on behalf of the Towns of Bethel, Redding, Weston, and Wilton, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between Plumtree Substation, Bethel and Norwalk Substation, Norwalk.

55. **In re: The City of Vernon, California,** Docket No. EL02-103 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting calendar year 2001 transactions.

56. **In re: San Diego Gas & Electric Company et. al.,** Docket No. EL00-95-045 on behalf of the City of Vernon, California before the Federal Energy Regulatory Commission concerning refunds and other monies payable in the California wholesale energy markets.

57. **In re: The City of Vernon, California,** Docket No. EL03-31 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2002 transactions.

58. **In re: Jersey Central Power & Light Company,** Docket Nos. ER02080506, ER02080507, ER02030173, and EO02070417 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in

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Has Testified

base tariff rates.

59. **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability rules, standards and indices.

60. **In re: Central Maine Power Company,** Docket No. 2002-665, on behalf of the Maine Public Advocate and the Town of York before the Maine Public Utilities Commission concerning a Request for Commission Investigation into the New CMP Transmission Line Proposal for Eliot, Kittery, and York.

61. **In re: Metropolitan Edison Company,** Docket No. C-20028394, on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission concerning the reliability service complaint of Robert Lawrence.

62. **In re: The California Independent System Operator Corporation,** Docket No. ER00-2019 *et al.* on behalf of the City of Vernon, California, before the Federal Energy Regulatory Commission concerning wholesale transmission tariffs, rates and rate structures proposed by the California ISO.

63. **In re: The Narragansett Electric Company,** Docket No. 3564 on behalf of the Rhode Island Department of Attorney General, before the Rhode Island Public Utilities Commission concerning the proposed relocation of the E-183 transmission line.

64. **In re: The City of Vernon, California,** Docket No. EL04-34 on behalf of the City of Vernon before the Federal Energy Regulatory Commission concerning Vernon's transmission revenue balancing account adjustment reflecting 2003 transactions.

65. **In re: Atlantic City Electric Company,** Docket No. ER03020110 on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

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66. **In re: Connecticut Light & Power Company and the United Illuminating Company,** Docket No. 272 on behalf of the Towns of Bethany, Cheshire, Durham, Easton, Fairfield, Hamden, Middlefield, Milford, North Haven, Norwalk, Orange, Wallingford, Weston, Westport, Wilton, and Woodbridge, Connecticut before the Connecticut Siting Council concerning an application for a Certificate of Environmental Compatibility and Public Need for a new transmission line facility between the Scoville Rock Switching Station in Middletown and the Norwalk Substation in Norwalk, Connecticut.

67. **In re: Metropolitan Edison Company, Pennsylvania Electric Company, and Pennsylvania Power Company,** Docket No. I-00040102, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning electric service reliability performance.

68. **In re: Entergy Louisiana, Inc.,** Docket No. U-20925 RRF-2004 on behalf of Bayou Steel before the Louisiana Public Service Commission concerning a proposed increase in base rates.

69. **In re: Jersey Central Power & Light Company,** Docket No. ER02080506, Phase II, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey Board of Public Utilities concerning reliability issues involved in the approval of an increase in base tariff rates.

70. **In re: Maine Public Service Company,** Docket No. 2004-538, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 138 kV transmission line from Limestone, Maine to the Canadian border near Hamlin, Maine.

71. **In re: Pike County Light and Power Company,** Docket No. M-00991220F0002, on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utility Commission concerning the Company's Petition to amend benchmarks for distribution reliability.

72. **In re: Atlantic City Electric Company,** Docket No. EE04111374, on behalf of the New Jersey Division of Ratepayer Advocate before the New Jersey

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Board of Public Utilities concerning the need for transmission system reinforcement, and related issues.

73. **In re: Bangor Hydro-Electric Company,** Docket No. 2004-771, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a request to construct a 345 kV transmission line from Orrington, Maine to the Canadian border near Baileyville, Maine.

74. **In re: Eastern Maine Electric Cooperatve,** Docket No. 2005-17, on behalf of the Main Public Advocate before the Maine Public Utilities Commission concerning a petition to approve a purchase of transmission capacity on a 345 kV transmission line from Maine to the Canadian province of New Brunswick.

75. **In re: Virginia Electric and Power Company,** Case No. PUE-2005-00018, on behalf of the Town of Leesburg VA and Loudoun County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for transmission and substation facilities in Loudoun County.

76. **In re: Proposed Electric Service Reliability Rules, Standards, and Indices To Ensure Reliable Service by Electric Distribution Companies,** PSC Regulation Docket No. 50, on behalf of the Delaware Public Service Commission Staff before the Delaware Public Service Commission concerning proposed electric service reliability reporting, standards, and indices.

77. **In re: Proposed Merger Involving Constellation Energy Group Inc. and the FPL Group, Inc.**, Case No. 9054, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the proposed merger involving Baltimore Gas & Electric Company and Florida Light & Power Company.

78. **In re: Proposed Sale and Transfer of Electric Franchise of the Town of St. Michaels to Choptank Electric Cooperative, Inc.,** Case No. 9071, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the sale by St. Michaels of their electric franchise and service area to Choptank.

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Peter J. Lanzalotta
Has Testified

79. **In re: Petition of Rockland Electric Company for the Approval of Changes in Electric Rates, and Other Relief,** BPU Docket No. ER06060483, on behalf of the Department of the Public Advocate, Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning electric service reliability and reliability-related spending.

80. **In re: The Complaint of the County of Pike v. Pike County Light & Power Company, Inc.,** Docket No. C-20065942, et al., on behalf of the Pennsylvania Office of Consumer Advocate before the Pennsylvania Public Utilities Commission, concerning electric service reliability and interconnecting with the PJM ISO.

81. **In re: Application of American Transmission Company to Construct a New Transmission Line,** Docket No. 137-CE-139, on behalf of The Sierra Club of Wisconsin, before the Public Service Commission of Wisconsin, concerning the request to build a new 138 kV transmission line.

82. **In re: The Matter of the Self-Complaint of Columbus Southern Power Company and Ohio Power Company Regarding the Implementation of Programs to Enhance Distribution Service Reliability,** Case No. 06-222-EL-SLF, on behalf of The Office of The Ohio Consumers' Counsel, before the Public Utilities Commission of Ohio, concerning distribution system reliability and related topics.

83. **In re: Central Maine Power Company,** Docket No. 2006-487, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning CMP's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line between Saco and Old Orchard Beach.

84. **In re: Bangor Hydro Electric Company,** Docket No. 2006-686, on behalf of the Maine Public Advocate before the Maine Public Utilities Commission concerning BHE's Petition for Finding of Public Convenience & Necessity to build a 115 kV transmission line and substation in Hancock County.

85. **In re: Commission Staff's Petition For Designation of Competitive Renewable Energy Zones,** Docket No. 33672, on behalf of the Texas Office

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Peter J. Lanzalotta
Has Testified

of Public Utility Counsel, concerning the Staff's Petition and the determination of what areas should be designated as CREZs by the Commission.

86. **In re: Virginia Electric and Power Company,** Case No. PUE-2006-00091, on behalf of the Towering Concerns and Stafford County VA before the Virginia State Corporation Commission concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Stafford County.

87. **In re: Trans-Allegheny Interstate Line Company,** Docket Nos. A-110172 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning a request for a certificate of public convenience and necessity for electric transmission and substation facilities in Pennsylvania.

88. **In re: Commonwealth Edison Company,** Docket No. 07-0566, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning electric transmission and distribution projects promoted as smart grid projects, and the rider proposed to pay for them.

89. **In re: Commonwealth Edison Company,** Docket No. 07-0491, on behalf of the Illinois Attorney General, before the Illinois Commerce Commission, concerning the applicability of electric service interruption provisions.

90. **In re: Hydro One Networks ,** Case No. EB-2007-0050, on behalf of Pollution Probe, before the Ontario Energy Board, concerning a request for leave to construct electric transmission facilities in the Province of Ontario.

91. **In re: PEPCO Holdings, Inc.,** Docket No. ER-08-686-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

92. **In re: PPL Electric Utilities Corporation and Public Service Electric and Gas Company,** Docket No. ER-08-23-000, on behalf of the Joint Consumer Advocates, including the state consumer advocacy offices for the States of

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Peter J. Lanzalotta
Has Testified

Maryland, West Virginia, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

93. **In re: PPL Electric Utilities Corporation,** Docket Nos. A-2008-2022941 and P-2008-2038262, on behalf of Springfield Township, Bucks County, PA, before the Pennsylvania Public Utility Commission, concerning the need for and alternatives to proposed electric transmission lines and a proposed electric substation.

94. **In re: PEPCO Holdings, Inc.,** Docket No. ER08-1423-000, on behalf of the Maryland Office of Peoples' Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

95. **In re: Public Service Electric and Gas Company, Inc.,** Docket No. ER09-249-000, on behalf of the New Jersey Division of Rate Counsel, before the Federal Energy Regulatory Commission, concerning a request for incentive rates of return on transmission projects.

96. **In re: New York Regional Interconnect Inc.,** Case No. 06-T-0650, on behalf of the Citizens Against Regional Interconnect, before the New York Public Service Commission, concerning the economics of and alternatives to proposed transmission facilities.

97. **In re: Central Maine Power Company and Public Service of New Hampshire,** Docket No. 2008-255, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning CMP's and PSNH's Petition for Finding of Public Convenience & Necessity to build the Maine Power Reliability Project, a series of new and rebuilt electric transmission facilities to operate at 345 kV and 115 kV in Maine and New Hampshire.

98. **In re: PPL Electric Utilities Corporation, Docket No. A-2009-2082652 et al,** on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning the Company's application for approval to site and construct electric transmission facilities in Pennsylvania.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

99. **In re: Bangor Hydro-Electric,** Docket No. 2009-26, on behalf of the Maine Public Advocate, before the Maine Public Utilities Commission, concerning BHE's Petition for Certificate of Public Convenience & Necessity to build a 115 kV transmission line in Washington and Hancock Counties.

100. **In re: United States, et al. v. Cinergy Corp., et al.** Civil Action No. IP99-1693 C-M/S, on behalf of Plaintiff United States and Plaintiff-Intervenors State of New York, State of New Jersey, State of Connecticut, Hoosier Environmental Council, and Ohio Environmental Council, before the United States District Court for the Southern District of Indiana, concerning the system reliability impacts of the potential retirement of Gallagher Power Station Unit 1 and Unit 3.

101. **In re: Application of Potomac Electric Power Company, et al.** Case No. 9179, on behalf of the Maryland Office of Peoples' Counsel before the Maryland Public Service Commission concerning the application for a determination of need under a certificate of public convenience and necessity for the Maryland portion of the MAPP transmission line, and related facilities.

102. **In re: Potomac Electric Power Company v. Perini/Tompkins Joint Venture,** Case No. 9210, on behalf of Perini Tompkins before the Maryland Public Service Commission concerning a review of PEPCO's estimates of electric consumption by Perini Tompkins Joint Venture's temporary electric service at National Harbor during a 29 month period for which no metered consumption data is available.

103. **In re: Duke Energy Ohio, Inc.,** Case No. 10-503-EL-FOR, on behalf of the Natural Resources Defense Council and Sierra Club before the Public Utilities Commission Of Ohio, concerning a review of the reliability impacts that would result from closure of selected generating units as part of a review of Duke's 2010 Electric Long-Term Forecast Report and Resources Plan.

104. **In re: Detroit Edison Company,** Case Nos. U-16472 and 16489, on behalf of the Michigan Environmental Council and the Natural Resources Defense Council, before the Michigan Public Service Commission, concerning a review looking for studies of the reliability impacts that would result from closure of selected generating units as part of an electric rate increase case.

Proceedings In Which
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Has Testified

105. **In re: Potomac Electric Power Company,** Case No. 9240, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability performance.

106. **In re: ISO New England, Inc.,** Docket No. ER12-991-000, on behalf of the Conservation Law Foundation, before the Federal Energy Regulatory Commission, concerning proposals for procedures for obtaining temporary regulations addressing emissions from electric generating facilities.

107. **In re: Western Massachusetts Electric Company, Docket No. D.P.U. 11-119-C** on behalf of the Attorney General of the Commonwealth of Massachusetts, before the Massachusetts Department of Public Utilities, concerning storm preparation, performance, and restoration of electric service.

108. **In re: Delmarva Power & Light Company,** Case No. 9285, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning storm restoration expenses and tree trimming expenses as part of a base rate increase case.

109. **In re: Potomac Electric Power Company,** Case No. 9286, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning storm restoration expenses and tree trimming expenses as part of a base rate increase case.

110. **In re: Fitchburg Gas And Electric Company,** Civil Action No. 09-00023, on behalf of Marcia D. Bellerman, et al., before the Commonwealth of Massachusetts Superior Court, concerning company and electric system preparedness and execution in dealing with a major winter storm.

111. **In re: Duke Energy Indiana, Inc.,** Cause No. 44217, on behalf of Citizens Action Coalition of Indiana, Sierra Club, Save The Valley, and Valley Watch, before the Indiana Utility Regulatory Commission, concerning the role of transmission planning studies as part of the process of deciding whether to retire coal-fired generation or equip such generation with environmental retrofits.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

112. **In re: Indianapolis Power & Light Company,** Cause No. 44242, on behalf of Citizens Action Coalition of Indiana and the Sierra Club, before the Indiana Utility Regulatory Commission, concerning the role of transmission planning studies as part of the process of deciding whether to retire coal-fired generation or equip such generation with environmental retrofits.

113. **In re: Consumers Energy Company,** Case No. U-17087, on behalf of Michigan Environmental Council and Natural Resources Defense Council, before the Michigan Public Service Commission, concerning the role of transmission planning studies as part of the process of deciding whether to retire coal-fired generation or equip such generation with environmental retrofits.

114. **In re: Potomac Electric Power Company,** Case No. 9311, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters and tree trimming expenses as part of a base rate increase case.

115. **In re: Jersey Central Power & Light Company,** BPU Docket No. ER12111052, on behalf of the New Jersey Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning reliability issues and storm performance involved in the approval of an increase in base tariff rates.

116. **In re: Delmarva Power & Light Company,** Case No. 9317, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters as part of a base rate increase case.

117. **In re: PPL Electric Utilities Corporation,** Docket Nos. A-2012-2340872 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning the need for and alternatives to proposed electric transmission lines and proposed electric substations as part of the Northeast Pocono Reliability Project.

118. **In re: Baltimore Gas & Electric Co.,** Case No. 9326, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service

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Commission, concerning electric service reliability matters as part of a base rate increase case.

119. **In re: Jersey Central Power & Light Company,** BPU Docket Nos. EO13050391 and AX13030196, on behalf of the New Jersey Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning the prudency of costs incurred in response to major storms.

120. **In re: Potomac Electric Power Company,** Case No. 9336, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters as part of a base rate increase case.

121. **In re: Baltimore Gas & Electric Co.,** Case No. 9355, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability matters as part of a base rate increase case.

122. **In re: American Transmission Company LLC and Northern States Power Company – Wisconsin,** Docket No. 5-CE-142, on behalf of Citizens Energy Task Force, Inc. and Save Our Unique Lands of Wisconsin, Inc., before the Public Service Commission of Wisconsin, concerning the need for and the benefits expected from proposed transmission facilities.

123. **In re: Potomac-Appalachian Transmission Highline, LLC and PJM Interconnection, LLC,** Docket Nos. ER09-1256-002 and ER12-2708-003, on behalf of Intervenors' State Agencies, including the Virginia Office Of The Attorney General's Division Of Consumer Counsel, the Delaware Division Of The Public Advocate, the Maryland Office Of People's Counsel, the Maryland Public Service Commission, the Delaware Public Service Commission, and the Pennsylvania Office Of Consumer Advocate, before the Federal Energy Regulatory Commission, concerning transmission line abandonment costs.

124. **In re: The Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.,** Case No. 9361, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a proposed merger case.

Proceedings In Which
Peter J. Lanzalotta
Has Testified

125. **In re: the Matter of the Application of the Ohio Edison Company, the Cleveland Electric Illuminating Company and the Toledo Edison Company for Authority to Provide for an Electric Security Plan,** Case No. 14-1297-EL-SSO, on behalf of the Sierra Club, before the Public Utilities Commission Of Ohio, concerning electric system reliability and transmission matters.

126. **In re: Delmarva Power & Light Company,** Case No. 9393, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning an application for a CPCN for a new 138 kV electric transmission line.

127. **In re: The Baltimore Gas & Electric Company,** Case No. 9406, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

128. **In re: The Potomac Electric Power Company,** Case No. 9418, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

129. **In re: The Matter Of Nova Scotia Power Performance Standards ,** Case No. M07387, on behalf of the Nova Scotia Consumer Advocate, before the Nova Scotia Utility and Review Board, concerning electric service reliability-related performance standards.

130. **In re: the Matter of the Application of the Ohio Power Company,** Case No. 13-1939-EL-RDR, on behalf of the Ohio Consumers' Counsel, before the Public Utilities Commission Of Ohio, concerning Phase 2 of its gridSMART Project and its gridSMART Phase 2 Rider.

131. **In re: PECO Energy Company,** Docket No. P-2016-2546452 et al., on behalf of the Pennsylvania Office of Consumer Advocate, before the Pennsylvania Public Utility Commission, concerning a proposed microgrid pilot plan and recovery of its costs.

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Has Testified

132. **In re: The Delmarva Power & Light Company,** Case No. 9424, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

133. **In re: Jersey Central Power & Light Company,** BPU Docket No. EO16080750, on behalf of the New Jersey Division of Rate Counsel, before the New Jersey Board of Public Utilities, concerning a determination that a proposed transmission line in Monmouth County NJ is necessary for the service, convenience, and welfare of the public.

134. **In re: Virginia Electric and Power Company,** SCC Case No. PUE-2016-00021, on behalf of Lancaster County, Virginia, before the Virginia State Corporation Commission, concerning the need for rebuilding an existing electric transmission line across the Rappahannock River and the desirability of placing such rebuilt transmission line underground.

135. **In re: Virginia Electric and Power Company,** SCC Case No. PUR-2017-00002, on behalf of Fairfax County, Virginia, before the Virginia State Corporation Commission, concerning the need for rebuilding an existing electric substation and the desirability of transmission lines in the vicinity being placed underground.

136. **In re: The Potomac Electric Power Company,** Case No. 9443, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

137. **In re: The Delmarva Power & Light Company,** Case No. 9455, on behalf of the Maryland Office of Peoples' Counsel, before the Maryland Public Service Commission, concerning electric service reliability-related matters as part of a base rate increase case.

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Has Testified

138. **In re: Entergy New Orleans, Inc.,** Docket No. UD-16-02, on behalf of the Sierra Club, the Deep South Center For Environmental Justice, and the Alliance For Affordable Energy, before the Council of the City of New Orleans, concerning electric service reliability-related matters.

139. **In re: Delmarva Power & Light Company,** Docket No. 17-0977, on behalf of the Delaware Division of the Public Advocate, before the Delaware Public Service Commission, concerning electric service reliability-related matters.

140. **In re: Virginia Electric and Power Company,** SCC Case No. PUR-2017-00143, on behalf of Fairfax County, Virginia, before the Virginia State Corporation Commission, concerning the need for building a new 230 kV transmission line and related facilities and the desirability of this new transmission line being placed underground.

141. **In re: the Matter of the Application of the Duke Energy Ohio, Inc.,** Case No. 17-0032-EL-AIR et al, on behalf of the Ohio Consumers' Counsel, before the Public Utilities Commission Of Ohio, concerning the establishment of Minimum Reliability Performance Standards for electric service.

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Exhibit___(PJL-3)

OCA Statement No. 2

Updated Group 1 Detailed Results

Project Name	Company	Cost	In-service Date	B/C 2015 Sensitivity	B/C with Recommended Groups 2-19 projects included	B/C Gas price increase sensitivty	B/C Gas price decrease sensitivty	B/C Load increase sensitivty	B/C Load decrease sensitivty	ApSouth Congestion Delta ($ millions) (2019+2022)	AEP-DOM Congestion Delta ($ millions) (2019+2022)
201415_1-6B	Dominion	25.00	2019	2.37	1.94	1.48	1.82	2.02	1.97	-$10.9	$2.9
201415_1-6C	Dominion	39.1	2019	4.07	4.64	4.05	3.46	5.05	4.60	-$91.7	$2.3
201415_1-6D	Dominion	42.70	2019	2.93	2.42	2.93	2.67	3.06	2.64	-$52.6	$2.5
201415_1-9A	DOM High Voltage/Transource	300.7	2020	5.07	2.64	2.09	3.39	3.02	2.56	-$134.0	-$10.9
201415_1-14A	DATC	51.53	2019	3.73	1.76	1.35	2.13	2.19	1.72	-$37.4	-$0.2
201415_1-19G	LSPower	48.60	2020	2.09	2.76	1.82	4.17	4.13	2.81	-$7.9	$8.0
201415_1-17A	Nextera	16.5	2019	3.96	3.64	1.89	3.84	5.34	4.83	-$45.2	$28.2
201415_1-17C	Nextera	15.7	2019	4.83	2.45	1.35	2.97	5.79	3.14	-$42.5	$20.8
201415_1-18E	FirstEnergy	66.0	2019	2.63	1.71	1.92	1.60	1.93	2.08	-$65.8	$13.0
201415_1-19B	LSPower	38.9	2020	11.34	4.07	2.68	2.82	4.08	3.47	-$19.0	$28.7
201415_1-19C	LSPower	41.90	2020	13.45	5.66	5.49	3.67	6.17	4.02	$56.4	-$6.0
201415_1-6A	Dominion	25.00	2019	3.48	3.22	3.86	0.86	3.90	4.26	N/A	N/A
201415_1-7A	Transource	155.36	2020	1.44	1.46	1.64	1.88	1.81	1.15	N/A	N/A
201415_1-7B	Transource	270.8	2021	1.37	1.11	0.71	1.10	1.08	1.08	N/A	N/A
201415_1-7C	Transource	240.0	2021	1.40	1.36	1.28	1.24	1.41	1.41	N/A	N/A
201415_1-17B	Nextera	41.00	2019	1.55	1.43	0.85	2.00	2.69	1.52	N/A	N/A
201415_1-17D	Nextera	36.4	2019	2.47	1.29	0.59	1.11	2.21	1.52	N/A	N/A
201415_1-17E	Nextera	297.0	2020	2.77	1.48	1.12	1.87	1.84	1.59	N/A	N/A
201415_1-18F	FirstEnergy	68.00	2019	2.62	1.13	1.60	1.34	1.55	0.92	N/A	N/A
201415_1-19D	LSPower	104.5	2020	8.19	1.50	1.09	1.84	2.23	1.71	N/A	N/A
201415_1-19F	LSPower	432.50	2023	1.29	1.19	1.16	2.71	1.16	1.26	N/A	N/A
201415_1-2C	PPL	33.95	2018	0.65	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-8A	Dominion/Transource	384.00	2020	0.56	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-8B	Dominion/Transource	293.00	2020	0.99	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-8C	Dominion/Transource	317.00	2020	0.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-8D	Dominion/Transource	222.00	2020	0.78	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-8E	Dominion/Transource	181.00	2019	0.88	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-8F	Dominion/Transource	193.00	2021	1.21	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-17F	Nextera	76.20	2019	0.90	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-17G	Nextera	86.30	2019	1.11	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-19E	LSPower	53.70	2020	0.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-20A	ITC	209.56	2020	0.25	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-20G	ITC	174.36	2020	0.21	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-20J	ITC	212.58	2020	0.32	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-20K	ITC	177.38	2020	0.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-20L	ITC	226.33	2020	0.17	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-20M	ITC	229.35	2020	0.45	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-20N	ITC	191.12	2020	0.71	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-20O	ITC	194.14	2020	0.66	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-22A	Ameren	46.6	2019	0.75	N/A	N/A	N/A	N/A	N/A	N/A	N/A
201415_1-22B	Ameren	46.6	2019	0.75	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Tier 1 finalists criteria: Projects with B/C>1.25 (all scenarios), ApSouth Congestion Delta<$10 million, AEP-DOM Congestion Delta <$10 million

*Negative represents a reduction as a result of the project

Exhibit___(PJL-4)

OCA Statement No. 2

Updated Group 1 Tier 1 Project Finalists

Project Name	Company	Cost	In-service Date	B/C 2015 Sensitivity	B/C with Recommended Groups 2-19 projects included	B/C Gas price increase sensitivty	B/C Gas price decrease sensitivty	B/C Load increase sensitivty	B/C Load decrease sensitivty	ApSouth Congestion Delta ($ millions) (2019+2022)	AEP-DOM Congestion Delta ($ millions) (2019+2022)
201415_1-6B	Dominion	25.00	2019	2.37	1.94	1.48	1.82	2.02	1.97	-$10.9	$2.9
201415_1-6C	Dominion	39.1	2019	4.07	4.64	4.05	3.46	5.05	4.60	-$91.7	$2.3
201415_1-6D	Dominion	42.70	2019	2.93	2.42	2.93	2.67	3.06	2.64	-$52.6	$2.5
201415_1-9A	DOM High Voltage/Transource	300.7	2020	5.07	2.64	2.09	3.39	3.02	2.56	-$134.0	-$10.9
201415_1-14A	DATC	51.53	2019	3.73	1.76	1.35	2.13	2.19	1.72	-$37.4	-$0.2
201415_1-19G	LSPower	48.60	2020	2.09	2.76	1.82	4.17	4.13	2.81	-$7.9	$8.0

(Reference Only) Production Cost Delta ($ millions) (2019+2022)	(Reference Only) Gross Load Payment Delta ($ millions) (2019+2022)
-$15.6	$16.7
-$25.9	-$86.6
-$33.7	$4.2
-$67.1	-$48.3
-$18.4	$153.5
-$18.9	-$2.2

Tier 1 finalists criteria: Projects with B/C>1.25 (all scenarios), ApSouth Congestion Delta<$10 million, AEP-DOM Congestion Delta <$10 million

*Negative represents a reduction as a result of the project

Exhibit___(PJL-5)

OCA Statement No. 2

Reevaluation Results (updated 02/2018)

PJM Window Project ID	Baseline#	Type	Area	Constraint	Cost ($mill)	In-Service Date	B/C 2014/15 Window	BC Reevaluation 2017
201415_1-2A	b2690	Upgrade	PPL/BGE	Safe Harbor to Graceton 230 kV	$ 1.10	2019	14.4	1.72
201415_1-2B	b2691	Upgrade	ME/PPL	Brunner Island to Yorkana 230 kV	$ 3.10	2019	22.2	2.84
201415_1-4I	b2697.1-2	Upgrade	AEP	Fieldale to Thornton 138 kV	$ 0.75	2019	101.2	9.47
201415_1-4J	b2698	Upgrade	AEP	Jacksons Ferry to Cloverdale 765 KV	$ 0.50	2019	62	46.18
201415_1-9A	b2743.1-8, b2752.1-7	Greenfield	APS/BGE	AP-South	$340.60	2020	2.48	1.32*
201415_1-10B	b2693	Upgrade	COMED	Wayne to South Elgin 138 kV	$ 0.10	2019	6.4	25.03
201415_1-10J	b2692.1-2	Upgrade	COMED	Cordova to Nelson 345 kV	$ 24.60	2019	1.9	1.59
201415_1-10D	b2728	Upgrade	COMED	Loretto-Wilton 345 kV (RPM)	$ 11.50	2017	64.5	In-service
201415_1-11H	b2694	Upgrade	PECO	Peach Bottom 500 kV	$ 9.70	2019	3	5.70
201415_1-12A	b2689.1-2	Upgrade	DUQ	Dravosburg to West Mifflin 138 kV	$ 11.18	2018	2	2.63
201415_1-13E	b2695	Upgrade	DPL	Worcester to Ocean Pines (I) 69 kV	$ 2.40	2019	65.3	10.14
201415_1-18G	b2688.1-3	Upgrade	APS	Taneytown to Carroll 138 kV	$ 5.20	2019	90.1	8.50
201415_1-18I	b2696	Upgrade	APS/ATSI	Krendale to Shanor Manor 138 kV	$ 0.60	2019	123.4	78.88
Optimal Caps	b2729	Upgrade	DOM	AP-South	$ 8.98	2019	15.4	2.16

Note: * B/C ratio calculated based on the Market Efficiency Base Case posted on 1/9/2018

Exhibit___(PJL-6)

OCA Statement No. 2

	A	B	C	D	E	F	G	H	I	J	K	L
1												
2		**Annual Projections of Load for PJM Mid-Atlantic (MW)**										
3	**Year of Forecast**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
4	**2012**	59,457	60,569	61,883	63,083	63,948	64,471	64,954	65,733	66,408	67,032	67,648
5	**2013**		59,736	60,778	62,025	63,051	63,767	64,184	64,786	65,585	66,189	66,788
6	**2014**			60,331	61,364	62,095	62,636	62,985	63,657	64,157	64,620	65,070
7	**2015**				58,901	59,711	60,315	60,737	61,205	61,639	62,058	62,527
8	**2016**					57,174	57,736	58,194	58,464	58,523	58,310	58,438
9	**2017**						57,164	57,332	57,330	57,217	56,789	56,730
10	**2018**							56,601	56,441	56,283	55,999	56,070
11												
12	**Unrestricted Peak**	60,067	59,580	54,964	54,890	56,666	55,220					
13												

Exhibit___(PJL-7)

OCA Statement No. 2

U.S. DEPARTMENT OF ENERGY

National Electric Transmission Congestion Study

September 2015

United States Department of Energy
Washington, DC 20585

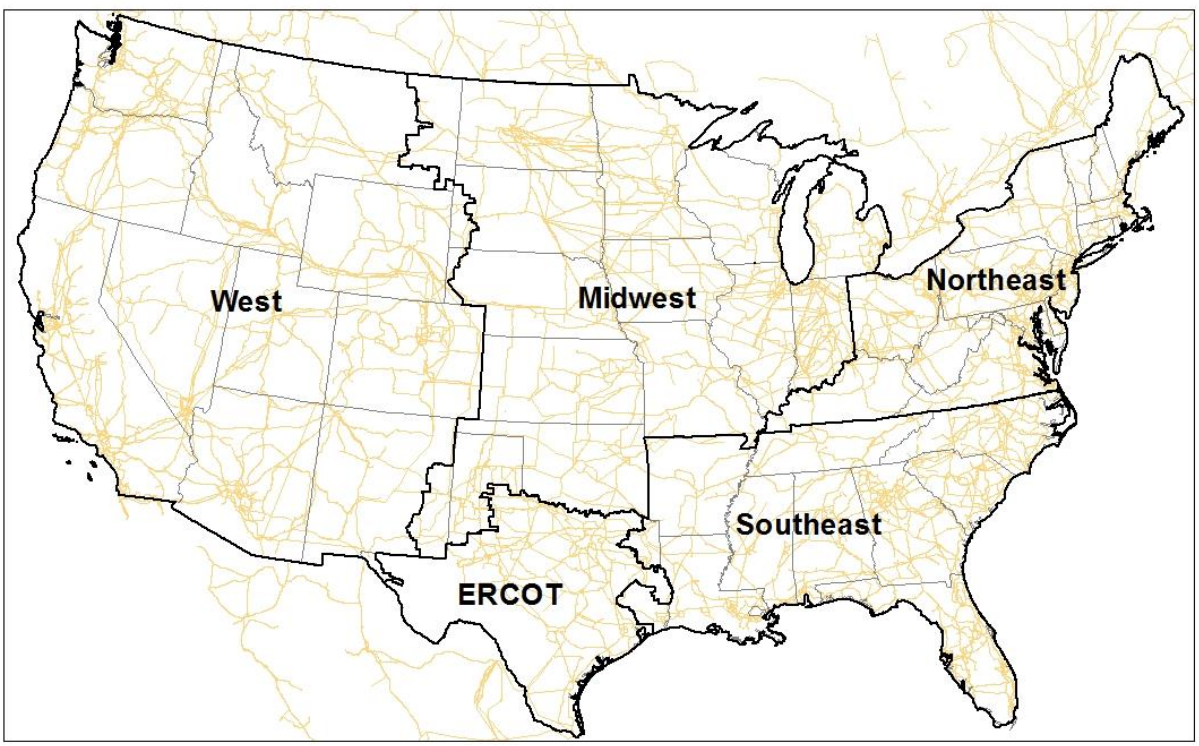
Executive Summary

The Energy Policy Act of 2005 amended the Federal Power Act (FPA) to require the U.S. Department of Energy (DOE, the Department) to conduct a transmission congestion study every three years, in consultation with the states and appropriate regional reliability entities. DOE published its first study in 2006, and a second for 2009, which was released in early 2010. This is the Department's third congestion study. It is based on publicly available data through 2012, with limited updates in December 2013.

Differences between this Study and Previous Congestion Studies

In this study the Department seeks to provide information about congestion by focusing on specific indications of transmission constraints and congestion—and their consequences. It focuses primarily on a specific time frame: historical trends over the few years prior to 2012 (with limited updates in 2013), and looking into the future to the extent available studies permit. It does not apply congestion labels to broad geographic areas such as the "critical congestion areas," "congestion areas of concern," and "conditional congestion areas" identified in earlier studies. For analytic convenience, the study's results are presented and discussed in relation to four large regions of the United States: the West, Midwest, Northeast, and Southeast (see Figure ES - 1).[1] The area covered by the Electric Reliability Council of Texas (ERCOT) is excluded by law from this study.

Figure ES - 1. Regional boundaries used for this study



[1] *Map regions are drawn to show geographic boundaries and not necessarily electrical ones. Transmission facilities shown in stated regions are not necessarily owned or operated by entities within that region. Note: the area covered by ERCOT is excluded by law from DOE congestion studies.*

This study identifies (to the extent supported by publicly available data as of 2012, with limited updates in December 2013) where transmission constraints and congestion occur across the eastern and western portions of the United States' electric power system. All of the conclusions presented in this study are based on (and limited to) the data reviewed, all of which are publicly available data series, studies, analyses, and reports. DOE reviewed more than 450 sources in preparing this report, all of which are listed in Appendix E. In addition, the data used to develop the analysis and conclusions in this document is compiled in a companion report released by the Department in early 2014.[2] DOE did not conduct independent modeling for this study. The Department does not endorse and has not independently validated the data and analyses referred to in this study.

The transmission constraints and congestion identified in this study represent a snapshot in time that is dependent on available information. Recognizing the changeability of circumstances and information, Congress directed the Department to conduct a congestion study every three years. The Department plans to initiate a fresh study of transmission constraints and congestion impacts in 2015. In addition to the triennial congestion studies, the Department will work with the Energy Information Administration (EIA) and the Federal Energy Regulatory Commission (FERC) to prepare an annual *Transmission Data Review* summarizing publicly available data and information on transmission matters, including congestion.

Transmission Constraints and Congestion

Transmission constraints and congestion are related but distinctly different concepts. The term "transmission constraint" may refer to:

(1) An element of the transmission system (either an individual piece of equipment, such as a transformer, or a group of closely related pieces, such as the conductors that link one substation to another) that limits power flows;

(2) An operational limit imposed on an element (or group of elements) to protect reliability; or

(3) The lack of adequate transmission system capacity to deliver electricity from potential sources of generation (either from new sources or re-routed flows from existing sources when other plants are retired) without violating reliability rules.

Transmission constraints, as defined above in (1), are a result of many factors including load level, generation dispatch, and facility outages. Jointly, these conditions establish a specific level or limit—as in (2)—to the permissible flow over the affected element(s) in order to comply with reliability rules and standards established to ensure that the grid is operated in a safe and secure manner. Reliability standards, developed by the North American Electric Reliability Corporation

[2] United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.

(NERC) and approved by FERC, specify how equipment or facility ratings should be calculated to avoid exceeding thermal, voltage, and stability limits following credible contingencies.

Transmission operating limits, which constrain throughput on affected transmission elements, are identified to comply with these rules and practices. Thus, although it is commonly thought that transmission constraints indicate reliability problems, in fact, constraints result from compliance with reliability rules. However, when constraints frequently limit desired flows, or when these limits are violated to avoid shedding firm load, they may indicate reliability problems that warrant mitigation.

The term “congestion” refers to situations where transmission constraints reduce transmission flows or throughput[3] below levels desired by market participants or government policy (e.g., to comply with reliability rules). A high degree or level of transmission system utilization alone does not necessarily mean congestion is occurring. Congestion can only arise when there is a desire to increase throughput across a transmission path, but such higher utilization is thwarted by one or more constraints. Transmission congestion has costs—they may induce higher costs for consumers on the downstream side of the transmission constraint if the consumers’ electricity supplier(s) must rely on higher-cost generation sources, and they may make it more difficult to achieve policy goals such as increased reliance on renewable generation resources. Transmission congestion may also cause reliability problems where such constraints impact operations by limiting access to reserves.

The Department has defined these terms narrowly for the purpose of this study, to ensure that they are used consistently here; these terms sometimes have different meanings in industry usage.

This Study Does Not Make Recommendations to Address Transmission Constraints and Congestion

This study’s assessment of transmission constraints and congestion does not address whether or how to fix constraints or the congestion they may cause. The presence of transmission congestion reflects only a desire or demand for increased transmission system utilization.

Whether it is appropriate to mitigate transmission congestion requires information and judgment about the purposes or objectives that would be served which goes beyond this study’s snapshot of physical constraints and congestion in the transmission system. For example, increased flow of electricity from lower-cost generation sources could reduce the overall cost of supplying electricity to consumers, while increased flow of electricity from remote renewable generation could help meet state energy policy goals. The point is that determining whether to address congestion requires determining first what objectives would be met by doing so. These objectives may conflict. For example, new generation could create new transmission congestion and raise electricity supply costs if it is located upstream of a constraint, at the same time that it helps to

[3] Throughout this study, the terms “transmission flows” and “transmission throughput” are used interchangeably to refer to the transport of electricity over transmission lines.

satisfy an energy policy goal. The differing objectives relative to transmission congestion should be recognized in determining whether and how to relieve transmission constraints. This study seeks to inform these discussions but does not seek to resolve the questions that underlie them.

Further, the transmission system is dynamic. Transmission flows change continuously as load, generation, fuel prices, reliability rules and other factors change. The magnitude, duration and impact of constraints and congestion change by time of day, day of the week, season, and year. Both past experience and expectations for the continued persistence of transmission constraints and congestion should be considered when evaluating solutions.

This study's snapshot of current conditions does not capture the full value that may be provided by mitigating the congestion identified, because congestion solutions typically bring multiple benefits over a long time horizon—such as improved reliability, more efficient generation dispatch, increased usage of variable renewable resources, or lower customer bills (from energy efficiency or other factors) on the load-side of a congested path. For example, one of the most strategically significant aspects of major new transmission projects that is seldom taken into account explicitly in the planning phase is that transmission may serve multiple purposes over a long life – typically 40 years or more. That is, a well-designed transmission system enhancement will not only enable the reliable transfer of electricity from Point A to Point B—it will also strengthen and increase the flexibility of the overall transmission network. Stronger and more flexible networks, in turn, create real options to use the transmission system in ways that were not originally envisioned. In the past, these unexpected uses have often proven to be highly valuable and in some cases have outweighed the original purposes the transmission enhancement was intended to serve. Past examples have included enabling grid operators to adjust smoothly and efficiently to unexpected yet ongoing changes in the relative prices of generation fuels, diverse renewable resource profiles, economic volatility, new environmental requirements, unanticipated outages of major generation and transmission facilities, and natural disasters. The options created by a strong and flexible transmission network are real. These benefits are important and should be recognized in a full assessment of potential solutions.

Moreover, it will not be appropriate to mitigate every transmission constraint or the congestion it causes. One must evaluate whether the benefits of mitigation—in monetary, policy, consumer impact, or other terms—outweigh or otherwise justify the costs involved. Such an evaluation should consider the ever-changing flows over the transmission grid, the length of time needed to design, site and build transmission solutions, transmission's long asset lifetime, and its many benefits over a lengthy time horizon. When the monetary, policy, or adverse consumer consequences of constraints and congestion rise to levels that warrant action, decision- and policy-makers will look at a variety of options to moderate or mitigate these costs, including creation of financial hedging mechanisms for congestion, deployment of energy efficiency or demand response to lower demand, construction of new generation, changes in other market mechanisms or operational rules, and the construction of new transmission facilities. This study does not evaluate or recommend particular solutions.

Indicators of Transmission Constraints and Congestion

Transmission constraints and congestion vary over time and location as a function of many factors, including changes in the patterns of electricity consumption, changes in the relative prices of the fuels and thus generating units used to generate electricity, and changes in the real-time availability of specific grid-related assets (such as power plants or transmission lines). There is also significant variation between and within regions in practices to manage congestion. This means that different kinds of indicators of congestion are relevant.

Some empirical indicators of congestion are:

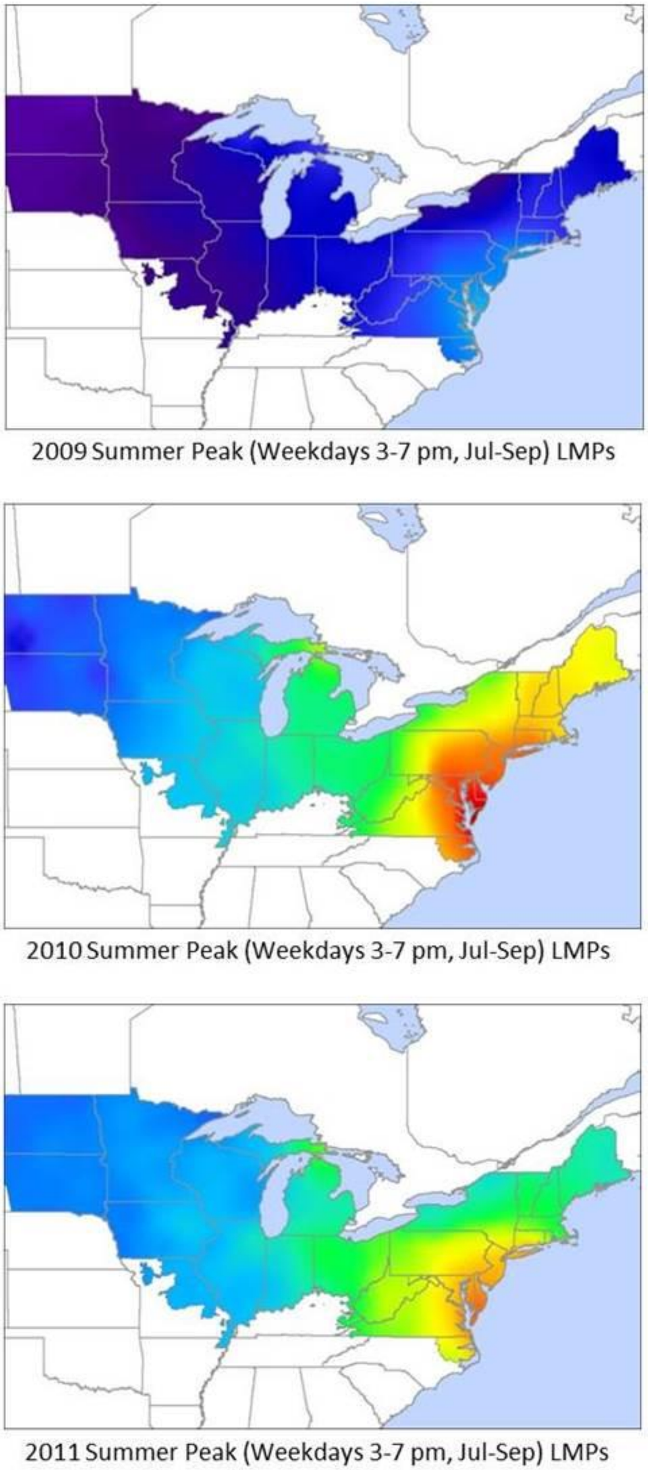
- Frequent usage by grid operators of transmission loading relief (TLR) or equivalent procedures to mitigate congestion. These procedures typically involve shifting to a different combination of generation and transmission facilities so as to mitigate potential or actual operating security-limit violations while respecting transmission service reservation priorities.
- Frequent or recurrent disparities in wholesale electricity prices across regional markets, as seen in congestion costs reported by Regional Transmission Operators (RTOs) and Independent System Operators (ISOs), differentials in locational marginal prices (LMPs), differentials in forward prices for generation capacity, and differences in prices at wholesale electricity trading "hubs." For example, in a market operated by an RTO, when low-cost power is fully subscribed, higher cost sources are tapped, and LMP goes up. In such markets, persistent price separation between sub-regions is an indicator of delivery problems from the low-cost to the high-cost sub-regions. RTO markets reflect the economic cost effect of the congestion in the locational marginal prices for the different sub-regions. See Figure ES - 2 for an example of such price disparities across the Midwestern and Northeastern states.[4] It is possible to identify the consistent impacts of a few specific constraint points and congestion hot spots from pricing maps—in particular the Upper Michigan Peninsula, the Delmarva Peninsula, and New Jersey and New York City, and the constraints that follow the Appalachian Mountains from Pennsylvania and western Maryland into Virginia.
- "Queues" of proposed generation projects seeking interconnection studies by relevant regional or sub-regional grid planning authorities are indicators of potential transmission demand. Figure ES - 3 and Figure ES - 4 are maps of interconnection queues.[5] Large queues are not in and of themselves indications that transmission is or will become constrained. In particular, new generation interconnecting on the load-side of a traditionally constrained region may help to relieve congestion. Some proposed projects may never reach commercial viability or finalize interconnection.

[4] While the four organized markets pictured in these Figures dispatch their regions separately, there is some expectation that trades between systems are made on an economic basis, which makes price patterns spanning these markets relevant to examining potential congestion across seams.
[5] These maps show queues as of 2012, and were developed for the stand-alone companion report, *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, released in January 2014.

However, when the aggregate capacity in the queue is larger than available or projected transmission capacity connecting it to load regions, it is an indication that transmission may be or will become constrained depending on how many of these projects materialize and how capacity interconnection and energy delivery is pursued.[6]

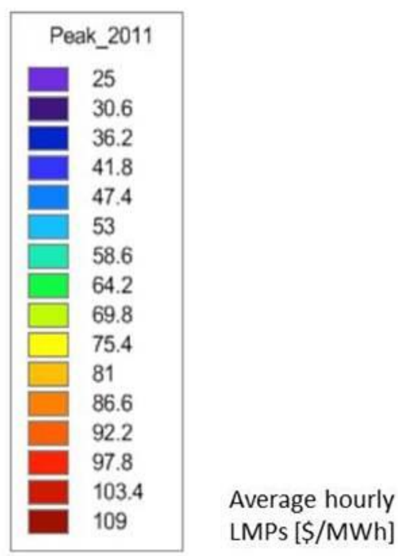
[6] Generators seeking interconnection are responsible for certain transmission system upgrades, depending on the type of interconnection service they request. (FERC (2003). *Standardization of Generator Interconnection Agreements and Procedures*. Docket No. RM02-1-000; Order No. 2003, July 24, 2003, at http://www.ferc.gov/legal/maj-ord-reg/land-docs/order2003.asp, p. 23)

Figure ES - 2. Summer peak LMPs for 2009, 2010, and 2011 ($/MWh)



This figure maps average hourly day-ahead LMPs across the MISO, PJM, New York and New England markets for the peak hours of 2009, 2010, and 2011. Peak hours are defined here as non-holiday weekday afternoons (3-7 pm, eastern standard time) July through September. This comparison reveals several points:

- Energy prices are lowest in the western part of the region, where there is extensive low-cost wind and coal generation, and increase to the eastern region, where most of the load is concentrated.
- The highest prices are concentrated in the heavily populated stretch from upper North Carolina through coastal Virginia, Maryland, Pennsylvania, Delaware, New Jersey, New York City, and southwest Connecticut – all areas that have limited supplies of low-cost generation and long-standing transmission constraints to the west across the Appalachian Mountains, although in some cases congestion may be due to planned transmission outages.
- LMPs were highest in 2010 (when natural gas prices were slightly higher and consistently higher temperatures pushed loads very high) and lowest in 2009.



Source: Ventyx (2012). "Ventyx Velocity Suite."

Figure ES - 3. Midwest interconnection queue map (created June 2012)

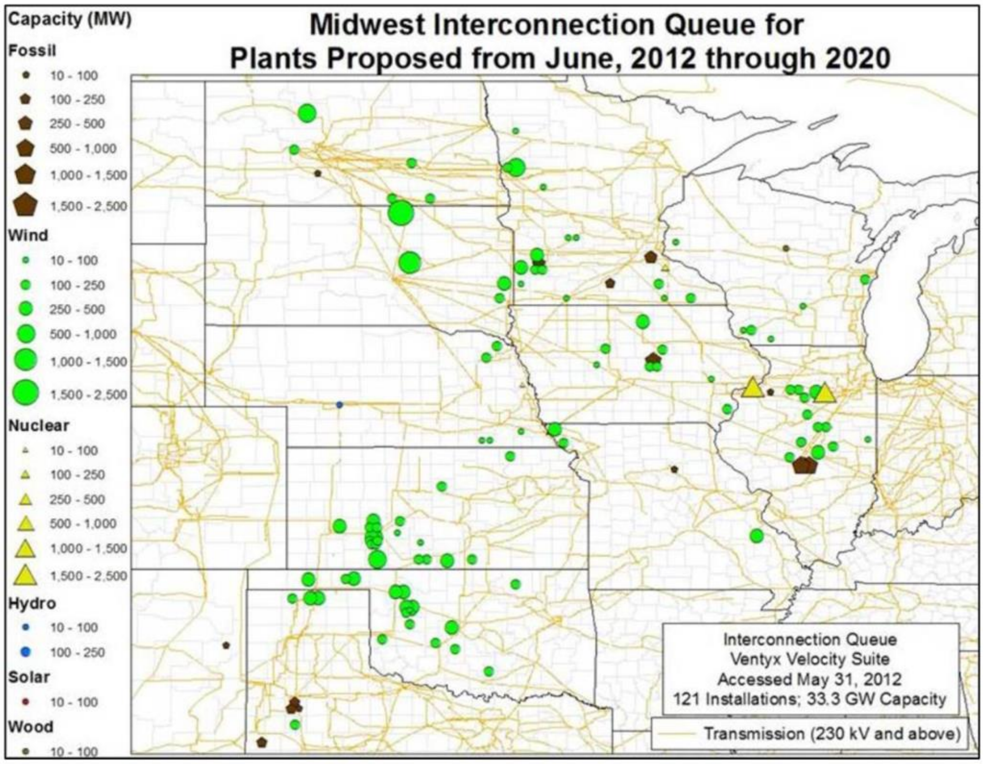
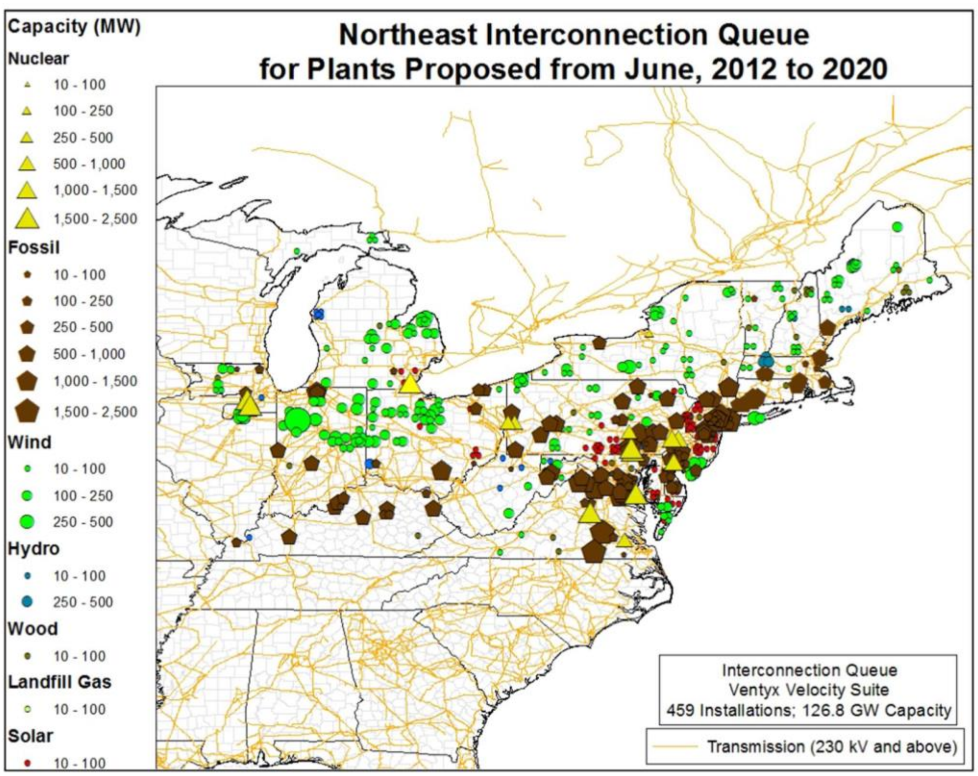


Figure ES - 4. Northeast interconnection queue map (created June 2012)



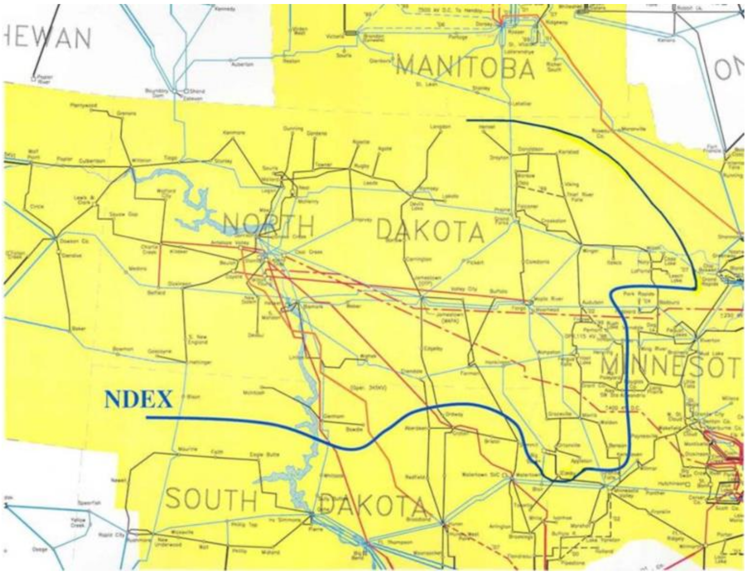
Recent Nation-Wide Trends Affecting Transmission Constraints and Congestion since the 2009 Congestion Study

Transmission constraints and congestion are influenced by both broad, economy-wide trends or conditions, and unique regional and sometimes local circumstances. The Department found that several broad, nation-wide trends have affected transmission usage patterns since the publication of the 2009 Congestion Study. In most areas, the net effect of these trends has been a reduction in the incidence of congestion and its economic costs. These trends are:

- The economic recession of 2008–2009 reduced electricity demand significantly. In the ensuing economic recovery, electricity demand growth has still been lower than its long-term historical trend, relative to the rate of economic growth. All else equal, lower electricity demand frequently means lower transmission usage and lower congestion.
- State and federal governments and many utilities are implementing policies to improve energy efficiency. These improvements in efficiency put downward pressure on electricity demand across the country. Many utilities, ISOs and RTOs have implemented robust demand response programs to pay loads and reduce consumption during periods of peak demand, which has tended to lower system peak demands and energy consumption, and therefore, to lower congestion.
- Sustained investment in transmission and construction of major new transmission projects in many areas has also helped to reduce congestion.
- Compliance with state renewable portfolio standards (RPSs) and goals has been significant. In response to the RPSs, renewable output has risen sharply. Responsibility for who pays for the transmission to interconnect this new generation has not been definitively settled in all areas. Increased generation from renewables in remote locations, though generally beneficial, is increasing congestion in some areas (between prime resources and load centers). For example, Figure ES - 5 shows the North Dakota Export Limit (NDEX), a long constraint that crosses parts of North Dakota, Minnesota, and South Dakota limiting the flow of major new wind resources out of the constrained area. In other regions, congestion on the high voltage transmission system is less of a concern for interconnection and operation of renewable resources.[7]

[7] RPSs do not directly require investment in infrastructure. In some regions, like ISO-NE, the owners of the new capacity or Renewable Energy Certificate (REC) marketers are required to ensure adequate transmission capacity to deliver the resources or the load serving entity may make Alternative Compliance Payments, which also serve as a cap on the price of RECs. In other regions, sufficient transmission capacity already exists or is being added based on approved plans. For instance, a NYISO wind study indicates no major high voltage transmission additions would be necessary to accommodate additional wind resources, although certain contingencies and local transmission facilities cause some "bottling" of wind production.
NYISO (2010b). *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study.* Rensselaer, NY: NYISO. September 2010, available at http://www.uwig.org/growing_wind_-_final_report_of_the_nyiso_2010_wind_generation_study.pdf

Figure ES - 5. The North Dakota Export Limit (NDEX)



Source: Lein, J. (North Dakota Public Service Commission) (2011). "U.S. Department of Energy National Electric Transmission Congestion Study Workshop." Presented at the United States Department of Energy (2011a). "Material Submitted: Pre-Congestion Study Regional Workshops" at http://energy.gov/sites/prod/files/Presentation%20by%20Jerry%20Lein%2C%20ND%20PSC.pdf, p. 8.

- Abundant supplies of natural gas at low prices. This trend has had two effects:
    1. Some gas-fired generators are being used more intensively, and some coal-fired generators are being used less intensively. Because gas plants are often sited closer to load centers than the capacity being displaced, transmission usage and congestion patterns shift.
    2. Lower natural gas costs mean somewhat lower overall fuel costs for generation, and lower overall wholesale electricity prices. This means that even if a transmission constraint forces a buyer in a congested area to purchase from an alternate generator, the economic cost premium to the buyer may be lower than previously.
- Recent trends in retirement of both nuclear and coal-fired power plants have been changing transmission flows in many areas of the country.
- New environmental regulations—some still under development—affect the composition and usage of regional generation fleets. As coal-fired and other plants are retired or retrofitted, grid operators will modify dispatch patterns according to the economics of available generation and transmission capacity in relation to fluctuating electricity demand. Appropriate actions will be taken to maintain grid reliability, but congestion may increase or decrease in specific locations.

Regional Findings: Western Interconnection

The Western region contains one organized wholesale electricity market, which is operated by the California Independent System Operator (CAISO); the rest of the Western region consists of vertically integrated utilities, public power entities, and independent generators that trade bilaterally and cooperate for regional planning purposes.[8] There are many common issues across the West, but there is more extensive data availability within the CAISO than elsewhere, so that region is discussed separately in portions of this report. The CAISO serves an estimated 35% of electric load in the western interconnection.[9]

The Department's findings regarding congestion in the West are:

- Although a number of paths in the Western Interconnection are heavily utilized, most of these do not appear to be operating at such consistently high levels that they act as persistent, reliability-threatening transmission constraints. In 2009 (the only year for which data is publicly available), unscheduled flow mitigation procedures were used less than 0.5% of the hours of the year.
- With respect to the economic consequences of congestion, there is only information available about the area covered by CAISO. That information indicates that individual transmission constraints limit system operations in at most 8% of the year, and that these constraints do not increase electric prices and congestion costs by a significant amount.
- There has been a marked increase in transmission construction and project completions across the West over the past three years, and equal progress in planning and coordination of new transmission project proposals. These completions have already improved western transmission throughput, reducing usage on many key interfaces and reducing congestion and associated costs.
- In addition, the permanent closure of the San Onofre Nuclear Generating Station has created some local reliability challenges for Southern California. A preliminary inter-agency plan has proposed several near- and longer-term transmission, resource and regulatory solutions to ensure reliability in this area, and to address existing congestion that was exacerbated by the plant closure.
- Although current congestion in the West is relatively low, in the next few years more congestion is expected due to transmission constraints related to new development of renewable resources and upcoming generator retirements. This is evidenced by WECC's list of Common Case Transmission Projects, which are not yet built or operational, but are assumed to become so within ten years for the purposes of WECC's interconnection-wide planning studies. Congestion resulting from these constraints could be exacerbated by higher demand growth induced by extreme weather or economic activity.

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[8] The western provinces of Canada and the northern portion of Mexico are also part of this electrically interconnected system, but they are not included in this analysis.
[9] California ISO (CAISO) (2012e), "The ISO grid," at http://www.caiso.com/about/Pages/OurBusiness/UnderstandingtheISO/The-ISO-grid.aspx.

- Many factors make future congestion patterns hard to predict—these complications include the impacts of environmental regulations (both federal and state level), state RPS compliance requirements, the pace of general economic recovery, relative fuel prices for electricity generation, new natural gas, nuclear, and other generation construction, and the feasibility of building long high-voltage transmission lines across federal lands.

Regional Findings: Midwest

The Midwest area contains the Midcontinent ISO (MISO),[10] Southwest Power Pool (SPP),[11] the far western portion of PJM, and some areas that are not part of an RTO or organized wholesale power market. Although the ISOs and RTOs in the Midwest collect data about transmission constraints, congestion costs, and LMPs, these terms are defined and calculated differently in each ISO and RTO. For this reason, transmission constraints and congestion matters are considered on an RTO- or ISO-specific basis.[12]

The Department's findings regarding congestion in the Midwest are:

- Congestion results from high and growing levels of wind generation that cannot be delivered from the western side to more distant, eastern loads, and the lack of additional transmission to enable further development in renewable-rich areas. These factors resulted in higher real-time congestion costs in central MISO.
- Congestion is also due to generation and capacity reserves that are higher in the western and central side of MISO than they are in the eastern part of the Midwest region, increasing west-to-east flows.[13] These factors resulted in higher real-time congestion costs at some locations on the interface between MISO and PJM.
- Congestion is also due to administrative and institutional differences that create "seams" between and among the western RTO/ISOs (MISO, PJM, and SPP) and the eastern RTO/ISOs (PJM and New York ISO via the "Lake Erie Loop"), which lead to loop flows, and pricing and scheduling inconsistencies. These RTOs/ISOs are aware of these issues and in many cases are actively working to address them.
- Real-time congestion costs increased to $1.24 billion for MISO in 2011, up 20% from 2010. In PJM, total congestion costs decreased to $1 billion in 2011, down 30% from 2010.

[10] In April 2013, Midwest ISO changed its name to Midcontinent ISO to reflect its broadening geographic scope.
[11] In 2015, Western Area Power Authority/Basin Integrated System will be joining the SPP.
[12] In this study, the western portions of PJM that are interspersed with MISO are presented as part of the Midwest, while the eastern portions of PJM are presented with the Northeast. Below in Section 6.2, the infrastructure update for PJM is fully presented in the Northeast section. In the data document accompanying this congestion study, economic congestion and other data are presented for the whole of PJM. (United States Department of Energy (2014). *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.)
[13] Potomac Economics (2012b). *2011 State of the Market Report for the MISO Electricity Markets*. Prepared by Potomac Economics for the Independent Market Monitor for MISO. June 2012, at http://www.potomaceconomics.com/uploads/midwest_reports/2011_SOM_Report.pdf, p.13.

- Interconnection queues for the Midwest, as of 2012, were dominated by siting requests for wind generation, generally in locations distant from population centers.

Regional Findings: Northeast

The Northeast region includes the footprints of the New York and New England ISOs and the eastern portion of PJM.[14]
The Department's findings regarding congestion in the Northeast are:

- Transmission constraints have limited flows across the Northeast for fewer hours per year (comparing 2009–2011 to 2008 and before).
- Generation and transmission additions across the Northeast in recent years have contributed to lower overall congestion, particularly within New England and PJM.
- Congestion is also down due to lower demand reflecting the economic recession of 2008–2009, aggressive energy efficiency and demand response, lower natural gas prices, and the resulting smaller price differentials between natural gas and competing generation fuels (e.g., coal). This reduces the economic incentive to use transmission to displace electricity from one source with electricity from another source using less costly fuel.
- Congestion costs for NYISO in 2012 were 50% below the $2.6 billion reported in DOE's previous congestion study (2009). Congestion costs for ISO-NE in 2012 were less than 10% of the ~$0.5 billion reported in 2009 by DOE.
- However, some congestion still exists. Much of the congestion that remains in the Northeast reflects three factors:
    - Transmission constraints continue to restrict delivery of power into load centers in central New York and the New York City and Long Island areas.
    - Increased quantities of low-cost onshore wind generation in concentrated locations remote from major load centers are shipped during off-peak hours as "as available capacity," because they exceed the throughput capability of existing transmission facilities. These facilities were designed to meet the on-peak demands of load centers rather than deliver off-peak generation from the remote wind locations.[15]
    - Administrative and institutional issues arising from different market rules, scheduling practices, and transmission reservations hinder more effective use of facilities between neighboring RTOs and ISOs and result in congestion at locations

[14] As mentioned above, the western portions of PJM that are interspersed with MISO are presented as part of the Midwest, while the eastern portions of PJM are presented with the Northeast. Below in Section 6.2, the infrastructure update for PJM is fully presented in the Northeast section. In the data document accompanying this congestion study, economic congestion and other data are presented for the whole of PJM. (United States Department of Energy (2014) *Transmission Constraints and Congestion in the Western and Eastern Interconnections, 2009-2012*, January 2014, at http://energy.gov/sites/prod/files/2014/02/f7/TransConstraintsCongestion-01-23-2014%20.pdf.)
[15] As noted above, increases in remotely-located renewables is not a concern in all regions, e.g. NYISO (2010b). *Growing Wind: Final Report of the NYISO 2010 Wind Generation Study.* Rensselaer, NY: NYISO. September 2010, available from http://www.uwig.org/growing_wind_-_final_report_of_the_nyiso_2010_wind_generation_study.pdf.

along the seams between markets. RTOs and ISOs in the Northeast are aware of these issues and in many cases are actively working to address them.[16]

Regional Findings: Southeast

The Southeast region covers North and South Carolina, Tennessee, Arkansas, Georgia, Alabama, Mississippi, Louisiana, Florida, and parts of (non-ERCOT) Texas. It includes some or all of the NERC regions of SERC (Southeast Reliability Corporation), SPP, and FRCC (Florida Reliability Coordinating Council).

The Department's findings regarding congestion in the Southeast are:

- There are no clear trends in the application of administrative congestion management procedures over the period 2006–2011, with the exception of an increase in level 5 TLRs (the most severe TLR level because it involves curtailment of firm transactions), called by ICTE (Entergy's Independent Coordinator of Transmission).
- There is one report of a persistent transmission constraint within the region.[17]
- As with the portions of the Western Interconnection outside of CAISO, there are no reports on the economic cost of congestion because no organized wholesale electricity markets operate in the Southeast which produce locational marginal prices that reflect differences in production costs due to congestion. Transmission is being built in coordination with generation additions following long-standing planning practices overseen by state and regional protocols.
- Interconnection queues indicate that future generation will consist largely of fossil-fuel and nuclear generation in Georgia, Alabama, and Florida, wind generation in the western part of the interconnection and in Tennessee, and solar in Florida.

The Need for Better Transmission Data

Table ES - 1 summarizes the main sources of information relied on to develop the transmission constraints and congestion data and to develop the findings presented in this report. Despite widespread agreement on the strategic importance of electric transmission infrastructure—to our economy, our quality of life, and our national security—there is little comprehensive, consistent information available on transmission usage, congestion and its economic consequences, or transmission investment. Transmission Open Access and the formation of ISOs and RTOs over the past two decades have dramatically increased the transparency of planning and operations information in various areas of the country. However, certain challenges remain. In particular:

[16] For instance, the development of Coordinated Transaction Scheduling between ISO-NE and NYISO, which will be described in more detail below. While FERC permits regional differences in strategies for system operations and market rules, FERC generally encourages coordination between different regions to support economically efficient trade. See, e,g., The Energy Daily (2013b). "FERC steps into 'seams' fight between MISO, PJM." December 23, 2013; The Energy Daily (2014). "FERC moves to defuse mushrooming SPP-MISO fight." April 1, 2014.

[17] Florida Municipal Power Agency (FMPA) submitted comments on the draft study that the Florida-Georgia interface is constrained. FMPA also provided information on OASIS service queues and available transmission capacity.

- Data are not available uniformly across the country. The most evident differences reflect the fact that portions of the country use organized and transparent markets to manage transmission system use, while others use administrative, non-public means. While there is a great deal of publicly available data on constraints and congestion within the regions with organized markets (i.e., CAISO, ISO-NE, MISO, NYISO, PJM, and SPP), the non-RTO/ISO regions have different methods for managing congestion and thus different kinds of data are available.
- Due to organizational or market-specific practices, each RTO and ISO has its own definitions, conventions, and practices for how LMPs and annual congestion costs are calculated and presented to the public. Similarly, differences in regional practices affect whether and how administrative congestion management procedures, such as unscheduled flow mitigations (UFMs) and TLRs, are used to manage transmission scheduling conflicts in operations.
- Data and practices can change over time, limiting trend assessment. The California ISO, for example, changed its market design in 2009, so pre-2009 market information is not directly comparable to later information. The PJM Interconnection's footprint expanded dramatically in 2004, creating another data discontinuity. Data comparisons and trend analysis must recognize and account for fundamental changes in a region's market organization and operation.

These issues make it difficult to compare transmission infrastructure availability, usage, investment, constraints, and congestion on a nation-wide basis. The discrepancies in data are of particular concern when the data cannot be compared among neighboring regions within the same interconnection; the impact of changes in one region on its connected neighbors cannot be correctly identified if the data are not comparable. Moreover, the data shared among regions within the same interconnection do not always follow the same database definitions. This makes it difficult to ensure that studies conducted by different parties are using the same nomenclature, models, connectivity, control settings, etc. for the same equipment, and makes it more likely that neighboring regions will produce conflicting analytical results.

Public Comment on the Draft Congestion Study

In the fall of 2014, the Department invited public comment on the draft Congestion Study with reference to several specific questions.[18] The questions on which the Department requested input, the other topics on which comments were provided, and the conclusions reached by the Department are summarized below.

In the draft study, the Department said that it

[18] The Department received a total of 97 public comments on the draft study, from 13 organizations and 82 individuals. The entities and individuals submitting these comments are listed in the appendices to this report and their comments are on posted on the Department's website http://www.energy.gov/oe/public-comments-received-draft-congestion-study. In addition, in its consultation with states and regional reliability entities, the Department received 13 comments addressed to its three questions.

… is particularly interested in comments on the reliance on publicly available data to assess congestion and transmission constraints. In Chapter 3 this study discusses the limitations of available data and indicates actions the Department intends to take to improve data quality and availability in the future. The Department invites comments on these plans, insight into whether such data would have value for other parties, and comment on possible issues relating to the collection and public availability of the targeted data.

After reviewing and considering the public comments, the Department's findings and conclusions regarding data are:

(1) The Department concludes that relying on publicly available data is appropriate and necessary for the preparation of its Congestion Studies. Doing so ensures transparency in the Department's analysis and would help to address questions that would likely arise in the event the Department seeks to designate National Corridors based on the findings of such analyses. Accordingly, the Department will continue to rely on publicly available data to assess transmission congestion and constraints in future congestion studies. It will, however, also consider incorporating previously non-public data in future studies, if the source agrees to make the data public via their inclusion in the study.

(2) The Department agrees that some additional public information was available on topics relevant to the study, and that the information was not included in the initial draft study. As noted below, additional data or information provided to the Department through the comment process has either been incorporated into the final study or will be considered by future congestion studies.

(3) The Department will continue to work with stakeholders to refine existing or new sources of publicly available data, in part through the vehicle of DOE's new annual *Transmission Data Review*.

In the draft study, the Department also invited comments on two questions related to the usefulness of the Congestion Studies and National Corridors:

Do the Congestion Studies continue to serve a useful purpose in informing the national discussion of transmission infrastructure needs? Should the scope and process for conducting such studies be modified to better serve this objective?
Does the possible designation of National Corridors, under the statutory language as presently written and interpreted by the courts, help to ensure that adequate and appropriate transmission infrastructure is built in a timely manner? Should the concept of such corridors, or the process for their designation be modified to better serve this objective?

After reviewing and considering the public comments, the Department's conclusions concerning the usefulness of triennial Congestion Studies are:

(1) Publication by DOE of an annual *Transmission Data Review* should be continued, as a means of making transmission data and information available to the public on a timely basis.

(2) Triennial Congestion Studies can serve a useful purpose other than providing a basis for designation of National Corridors, by focusing national attention on aspects of transmission infrastructure that may warrant other forms of federal attention and action.

(3) The Department recognizes that future Congestion Studies should be coordinated with regional transmission planning efforts, including those mandated by FERC Order No. 1000, and that some of these efforts are still being developed.

The Department's responses to comments concerning the designation of National Corridors will be presented in a separate document, *Report by the U.S. Department of Energy Concerning Designation of National Interest Electric Transmission Corridors* (forthcoming).

The Department also received and considered comments on a number of other topics related to the draft study. The Department's responses to these comments are:

(1) The suggestions for edits, corrections, and clarifications in the draft study have been considered and in most cases incorporated into the final study.

(2) The suggestions for improving future congestion studies are generally reasonable and will be taken into consideration when the Department prepares its next Congestion Study.

Finally, the Department received a number of comments on topics related to transmission development and construction. After considering these comments, the Department's responses to these comments are:

(1) Some of these comments refer to ways to improve the content of future Congestion Studies and the Department will take them into account in preparing future studies.

(2) Some of these comments, such as those pertaining to the use of eminent domain, burdens associated with easements, federal or state laws, regulations or policies concerning energy resource development are outside the scope of this Congestion Study.

Exhibit___(PJL-8)

OCA Statement No. 2

Trump Orders a Lifeline for Struggling Coal and Nuclear Plants

By Brad Plumer

June 1, 2018

WASHINGTON — President Trump has ordered Energy Secretary Rick Perry to "prepare immediate steps" to stop the closing of unprofitable coal and nuclear plants around the country, Sarah Huckabee Sanders, the White House press secretary, said on Friday.

It remains to be seen what actions Mr. Perry will recommend, but many of the proposals being floated within the Trump administration, according to a leaked internal memo, would involve drastic government intervention in America's energy markets.

Under one proposal outlined in the memo, which was reported by Bloomberg, the Department of Energy would order grid operators to buy electricity from struggling coal and nuclear plants for two years, using emergency authority that is normally reserved for exceptional crises like natural disasters.

That idea triggered immediate blowback from a broad alliance of energy companies, consumer groups and environmentalists. On Friday, oil and gas trade groups joined with wind and solar organizations in a joint statement condemning the plan, saying that it was "legally indefensible" and would force consumers to pay more for electricity.

In her statement, Ms. Sanders said that the ongoing retirement of coal and nuclear plants, which are being pushed out of competitive electricity markets by a glut of natural gas and renewable power, were "leading to a rapid depletion of a critical part of our nation's energy mix, and impacting the resilience of our power grid."

Grid operators disputed that. PJM Interconnection, which runs the Mid-Atlantic electric grid serving more than 65 million people, said in a statement that its grid was "more reliable than ever," and that any federal intervention "would be damaging to the markets and therefore costly to consumers" by raising electricity prices.

Mr. Trump, who campaigned on a pledge to revive the coal industry, has so far struggled to fulfill his promise. According to data from the Sierra Club, at least 25 coal plants have shut down since he took office, largely squeezed out by competition from natural gas, wind and solar power.

In September, in an attempt to stave off those powerful market trends, Mr. Perry asked the Federal Energy Regulatory Commission, which oversees regional electricity markets, to consider guaranteeing financial returns for any power plant that could stockpile 90 days' worth of fuel on-site, which could include many coal and nuclear plants. He argued that the loss of such plants would threaten "reliability and resiliency of our nation's grid."

But in January, the commission unanimously rejected Mr. Perry's request, saying that the nation's grids currently had plenty of spare electric capacity on hand, even with the loss of coal and nuclear units in recent years, and that grid operators had sufficient tools to keep the lights on.

That hasn't stopped the Trump administration from exploring other options. In April, FirstEnergy Solutions, an Ohio-based utility, announced that it would file for bankruptcy, threatening the future of three nuclear plants and two coal plants in Ohio and Pennsylvania.

The company had earlier sent a letter to Mr. Perry asking him to save the country's coal and nuclear plants by invoking Section 202(c) of the Federal Power Act, under which the Energy Department can order certain power facilities to stay open in a crisis, such as a hurricane.

A few days later, Mr. Trump mentioned the idea in public, telling coal miners at a rally in West Virginia: "Nine of your people just came up to me outside. 'Could you talk about 202?' We'll be looking at that 202. You know what a 202 is? We're trying."

The administration has also discussed invoking the Defense Production Act of 1950, which allows the federal government to intervene in private industry in the name of national security. (Harry S. Truman used the law to impose price controls on the steel industry during the Korean War.)

But legal experts say that neither law was designed to provide unprofitable industries with extended financial support.

"The idea of superseding the market for a full two years and directing that purchases be made from specific plants is well beyond any existing use of these statutory powers," said Joel B. Eisen, a professor of law at the University of Richmond in Virginia.

If the Trump administration were to invoke these two statutes, the move would almost certainly be challenged in federal court by natural gas and renewable energy companies, which could stand to lose market share.

Depending on what the Trump administration decides, an intervention to prop up unprofitable coal and nuclear plants could cost consumers between $311 million to $11.8 billion per year, according to a preliminary estimate by Robbie Orvis, director of energy policy design at Energy Innovation.

Some analysts have asserted that there is an environmental case for keeping the nation's ailing nuclear plants open, since, if they closed, their carbon-free electricity would most likely be replaced by natural gas and emissions would rise. A few states, including New York and New

Jersey, have offered subsidies to their struggling nuclear plants in the name of fighting climate change.

There is no environmental argument for keeping open coal plants, which are the most carbon-intensive form of power.

The leaked memo circulating within the White House does not mention climate change. Instead, it says that the loss of both coal and nuclear plants could threaten national security, given that Department of Defense installations are 99 percent dependent on the grid.

Among other things, the report asserts that natural gas pipelines are vulnerable to cyberattacks and that coal and nuclear plants are essential during extreme weather because they can keep large amounts of fuel on-hand.

Brad Plumer is a reporter covering climate change, energy policy and other environmental issues for The Times's climate team. @bradplumer

A version of this article appears in print on June 2, 2018, on Page A17 of the New York edition with the headline: Trump Orders Moves To Keep Waning Coal And Nuclear Sites Open.

https://www.nytimes.com/2018/06/01/climate/trump-coal-nuclear-power.html

accessed 09 11 18

Exhibit___(PJL-9)

OCA Statement No. 2

Application of Transource Pennsylvania LLC
Independence Energy Connection-East & West Projects
Docket Nos. A-2017-2640195 and A-2017-2640200

Interrogatories of the Office of Consumer Advocate
Set XXIII
(Responses dated 8/22/2018)

Data Request 02:
On July 24, 2018, Dominion Energy announced new plans to add 3,000 MW of new solar and wind generation during the 2020's. The Company's announcement also referenced a related filing the same day announcing that it was seeking to add 240 MW of solar energy in Virginia. (See attached Company press release.) Please discuss i) the extent to which these planned resources are currently reflected in the most recent evaluation of project 9A, ii) the date on which the results of the most recent evaluation of project 9A were published by PJM, and iii) if not yet reflected in any completed evaluation of project 9A, the time frame for including these planned resources in an evaluation of project 9A.

Dominion Energy Launches Grid Transformation Program, Paving Way for Virginia's Energy Future With 3,000 Megawatts of New Solar and Wind Planned by 2022 - *New law saves Dominion Energy Virginia customers hundreds of millions of dollars - Calls for unprecedented expansion of solar and wind energy to be in public interest - Provides significant boost to energy efficiency and EnergyShare programs - Reduces outages, speeds restoration and improves service through new technology*

Company Release - 07/24/2018 15:08

RICHMOND, Va., July 24, 2018 /PRNewswire/ -- Dominion Energy Virginia customers stand to benefit from a smarter, stronger and greener energy grid in the first set of plans filed today under the Grid Transformation & Security Act (GTSA). The landmark legislation, signed by Gov. Ralph Northam, became effective July 1 and provides a roadmap for Virginia's energy future. Dominion Energy is committing to having 3,000 megawatts of new solar and wind -- enough to power 750,000 homes -- under development or in operation by the beginning of 2022.

"Thanks to the Grid Transformation & Security Act, Dominion Energy plans to develop a system that meets the increasingly complex demands and expectations of our customers," said Ed Baine, Senior Vice President – Power Delivery. "And we are doing it with more renewable energy."

The law paves the way for expanded investments in renewable energy, smart grid technology, a stronger, more secure grid and energy efficiency programs, all while keeping rates affordable. It provides hundreds of millions of dollars in bill credits and rate reductions for customers, and expands the EnergyShare program to help Virginia's most vulnerable citizens.

The Grid Transformation & Security Act includes provisions for:

- $200 million in bill credits to customers, and $125 million in annual rate cuts due to tax relief
- Modernizing the energy grid to improve reliability, resiliency and the ability to integrate more renewable energy and emerging technology

- Significantly expanding the company's renewable energy fleet in Virginia
- Future testing of wind turbines off the coast of Virginia Beach

In today's regulatory filing, the company asked the State Corporation Commission (SCC) to approve the programs, investments and costs included in the first three years of the 10-year grid transformation program. The company will update the plan and request approval of additional programs and spending in later filings with the SCC.

Keeping Energy Affordable

Customers will continue to see affordable energy prices even as the company makes critical investments in grid transformation. Through the provisions of the new law, Dominion Energy customers will see significant savings, starting with the $133 million bill credit this month, another $67 million credit in January, and $125 million annually in rate cuts due to recent federal tax reform.

Additionally, customers who need assistance will benefit from the significant expansion of EnergyShare. The law directs Dominion Energy to commit at least $13 million in shareholder funds each year through 2028 for bill assistance and weatherization services for seniors, veterans, low-income customers and people with disabilities.

Expanding Virginia's Renewable Resources

The Grid Transformation & Security Act set Virginia's energy policy on a course for a massive expansion in new wind and solar energy -- 3,000 megawatts of which Dominion Energy is committed to having in operation or under development by the beginning of 2022. The projects will be a combination of assets developed and procured by the company.

In a related filing with the SCC today, Dominion Energy will seek to specifically add 240 megawatts of solar energy in Virginia. The proposed projects will continue to grow the company's solar fleet, which is already the sixth largest in the nation. Dominion Energy is also working this summer to gather input from stakeholders before announcing the next phase in its solar strategy later this year.

Later this summer, the company will seek SCC approval for its proposed Coastal Virginia Offshore Wind (CVOW) project. The 12-megawatt facility would be the first of its kind in the Mid-Atlantic, located in a federal lease area about 27 miles off the coast of Virginia Beach. The two-turbine test project is being developed through a partnership with Ørsted Energy of Denmark, a global leader in wind generation. It will provide valuable information that could lead to more extensive wind development.

Smart Grid Technology and Grid Security

Customers can expect better service under the grid transformation initiative, which includes the installation of approximately 2.1 million smart meters in homes and businesses. If approved by the SCC, these smart meters in conjunction with a new customer information platform will give customers more information and tools to better manage their energy use and bills. The approximately $450 million investment in smart meters and the customer information platform during the first three years of the initiative will be funded without any rate increase by using the reinvestment model enabled by the GTSA.

Smart meters and other grid transformation investments will help integrate new technologies like private solar and electric vehicle charging stations into the grid. Investments in intelligent grid devices, smart meters, and automated control systems will enable a "self-healing" grid which will speed the restoration process by quickly identifying and isolating outages.

New construction and material standards will improve grid resiliency and reduce outages caused by weather and other events. Additional measures will be taken to protect the grid against the growing threat of both physical and cyber-attacks. These measures include hardening substations serving critical facilities and the deployment of new intelligent devices and control systems which help energy companies detect and recover from events more quickly.

Other provisions of the GTSA reinforce efforts by Dominion Energy to place more vulnerable and outage-prone distribution lines underground. The latest expansion of the company's Strategic Underground Program (SUP) is now under review by the SCC.

Energy Efficiency

The GTSA directs Dominion Energy to propose at least $870 million in energy efficiency programs over the next decade, designed to help customers save energy and manage the demand on Virginia's electric system. The new law designates that at least five percent of energy efficiency programs must benefit low income, elderly or disabled individuals, most likely through residential weatherization upgrades.

Dominion Energy will file its initial proposals for new energy efficiency projects with the SCC for approval later this year following input provided by stakeholders.

"The GTSA lays out a very clear path for Virginia to reach a clean energy future that includes greater reliability, more security and grid resiliency," Baine said. "And it does this while ensuring prices remain reasonable and competitive. Virginia will make great strides in the coming years, because of the new law."

For more information visit: http://www.dominionenergy.com/next.

Customers and developers interested in learning more about the company's wind and solar expansion plans can contact renewableenergy@dominionenergy.com.

About Dominion Energy Nearly 6 million customers in 19 states energize their homes and businesses with electricity or natural gas from **Dominion Energy (NYSE: D).** The company is committed to sustainable, reliable, affordable, and safe energy and is one of the nation's largest producers and transporters of energy with over $75 billion of assets providing electric generation, transmission and distribution, as well as natural gas storage, transmission, distribution, and import/export services. As one of the nation's leading solar operators, the company intends to reduce its carbon intensity 50 percent by 2030. Headquartered in Richmond, Va., Dominion Energy contributes more than $20 million annually to the communities it serves and actively supports veterans and their families. Please visit http://www.dominionenergy.com/, Facebook or Twitter to learn more.

View original content with multimedia:http://www.prnewswire.com/news-releases/dominion-energy-launches-grid-transformation-program-paving-way-for-virginias-energy-future-with-3-000-megawatts-of-new-solar-and-wind-planned-by-2022--300685854.html

SOURCE Dominion Energy Virginia

Response:
Neither the Company nor PJM have information sufficient to form a belief about whether Dominion Energy or its affiliates will in fact place in service 3,000 MW of new solar and wind generation between 2020 and the end of 2029, or whether in fact any such generation capacity additions would be offset by the retirement of any generation resources. The Company and PJM further lack information sufficient to form a belief about whether Dominion Energy or its affiliates will in fact obtain the necessary approvals to construct solar generation facilities in Virginia to add 240 MW of new generation capacity, or otherwise to add 240 MW of solar energy to serve electric load in Virginia, or where such solar energy would be generated. The Company and PJM further lack information sufficient to form a belief about whether the 240 MW referenced in the question is a component of the 3,000 MW also referenced.

The Company and PJM also lack information to form a belief about the preparation, publication, or substance of the documents included with the question as Exhibit A, or the matters described therein.

(i) PJM has not assessed the extent to which the 3,000 MW of wind and solar generation described in the question was reflected in the most recent evaluation of Project 9A, reviewed at the February 2018 PJM Transmission Expansion Advisory Committee (TEAC) meeting. To do so would require PJM to speculate on the number of wind and solar projects that comprise the 3,000 MW as well as the size, location, and timing of each project. Nor is PJM in a position to speculate on the likelihood that each project would reach commercial operation. PJM does not include proposed generation as that described in the question in its FERC-approved RTEP Process PROMOD market efficiency analysis – including that which justified the need for Project 9A – until that generation is submitted to PJM through its new services queue, has received a completed System Impact Study, and has executed a Facilities Study Agreement (FSA) or Interconnection Service Agreement (ISA).

Additionally, PJM notes that absent specific information on the nature of the solar and wind projects described in the question, they may already be accounted-for in PJM load forecasts as discussed in the Company's responses to OCA-IV-24, OCA-IV-26, OCA-IV-27, OCA-IV-29, OCA-IV-31, OCA-IV-32, OCA-IV-34, OCA-IV-36, OCA-IV-37, OCA-IV-39, OCA-IV-41, OCA-IV-42, and OCA-XIII-17. Further, from a generation perspective, retirements from 2020 through 2029 could offset the wind and solar generation described in the question. PJM does not speculate on that either.

The Company notes that the most recent, second re-evaluation – February 2018 – justifying the need for Project 9A was discussed in responses to OCA-III-02, OCA-IV-13, OCA-IV-15, OCA-IV-16, OCA-IV-44, OCA-V-01, OCA-VI-02, OCA-VIII-01, OCA-VIII-02, OCA-VIII-04, OCA-IX-10, OCA-X-02, OCA-X-08, OCA-XI-10, OCA-XI-11,OCA-XIII-18, OCA-XVIII-03, OCA-XVIII-06, OCA-XX-01, OCA-XX-02, OCA-XXI-04, OCA-XXII-01, and OCA-XXII-03. The generators modeled in the analysis leading to that evaluation were provided in the .UNT and .TRN files provided in OCA-XVIII-03, OCA-XVIII-06, OCA-XX-01, OCA-XX-02, OCA-XX-03, OCA-XX-04, OCA-XX-05, OCA-XX-06. The results of a third re-evaluation of Project 9A are expected to be published by PJM in connection with the September 2018 TEAC meeting. See the Company's response to OCA-XXII-01.

(ii) See the Company's response to OCA-XXIII-02-(i).

(iii) The next, and third, re-evaluation of Project 9A is expected to be published by PJM in connection with the September 2018 TEAC meeting. Input parameters for that evaluation will not speculate on the 3,000 MW of wind and solar described in the question. See the Company's response to OCA-XXIII-02-(i).

Witness: Paul F. McGlynn

Exhibit___(PJL-10)

OCA Statement No. 2

E-1

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH ATLANTIC REGION (1973=100)

COST TRENDS OF E

NORTH ATLANTI

	A	B	C	ES	ET	EV	EW	EY	EZ	FB	FC	FE	FF	FH	FI	FK	FL	FN	FO	FQ	FR
5				COST INDEX NUMBERS																	
6				2011		2012		2013		2014		2015		2016		2017		2018		2019	
7	Line	CONSTRUCTION AND EQUIPMENT	FERC	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1
37	30	Gas Turbogenerators	344	693	714	767	785	808	803	822	838	859	863	886	903	926	944	970			
38	31																				
39	32	**Transmission Plant**																			
40	33	Total Transmission Plant		654	669	675	682	696	695	704	712	722	724	735	738	746	750	778			
41	34	Station Equipment	353	705	721	734	742	761	753	760	772	784	790	798	801	816	818	843			
42	35	Towers & Fixtures	354	561	563	576	576	595	585	593	600	609	611	617	620	626	617	634			
43	36	Poles & Fixtures	355	617	619	637	640	645	647	645	647	653	648	663	666	668	679	683			
44	37	Overhead Conductors & Devices	356	611	661	611	618	629	643	647	653	659	659	683	683	669	669	724			
45	38	Underground Conduit	357	590	596	626	627	625	623	648	646	658	655	667	669	680	684	703			
46	39	Underground Conductors & Devices	358	913	917	935	966	978	1000	1029	1040	1050	1055	1070	1070	1082	1130	1188			
47	40																				
48	41	**Distribution Plant**																			
49	42	Total Distribution Plant		634	649	667	679	689	701	714	720	734	735	745	744	753	766	787			

Exhibit___(PJL-11)

OCA Statement No. 2

Application of Transource Pennsylvania LLC
Independence Energy Connection-East Project
Docket No A-2017-2640195

Interrogatories of the Office of Consumer Advocate
Set I
(Responses dated 1/31/2018)

Data Request OCA-I-18:
Reference: Transource Statement 2 (East), p. 7, lines 9-17. Concerning the statements made in this paragraph:

a. Please provide the workpapers and other source documents used to determine the $800 million figure.
b. Approximately what percentage of the $800 million in additional AP South Interface congestion costs from 2012 through 2016 was charged to electricity consumers in Pennsylvania? Please provide all workpapers and other documents used in responding to this question.
c. What does Mr. Ali mean by "low voltages" as used in this paragraph?
d. Please identify each instance between 2012 and the present when the AP South Reactive Interface experienced "low voltages."
e. Please identify each instance between 2012 and the present when the AP South Reactive Interface experienced "voltage collapse."

Response:
a. The $800 million figure was determined by using information from the PJM State of the Market Reports. Specifically, the Grand Total Value for the AP South Reactive Interface is the sum of information taken from the following sources:

2016 Report
http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016.shtml
Section 11
Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): 2016

2015 Report
http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2015.shtml
Section 11
Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): 2015
Table 11-25 Top 25 constraints affecting PJM congestion costs (By facility): 2014

2013 Report
http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2013.shtml
Section 11
Table 11-18 Top 25 constraints affecting PJM congestion costs (By facility): 2013
Table 11-19 Top 25 constraints affecting PJM congestion costs (By facility): 2012

Application of Transource Pennsylvania LLC
Independence Energy Connection-East Project
Docket No A-2017-2640195

Interrogatories of the Office of Consumer Advocate
Set I
(Responses dated 1/31/2018)

Response to Data Request OCA-I-18 continued:

b. Transource does not have information that could be used to estimate the impact of particular market constraints on customers of load-serving entities in a particular state and time period.

c. The term "low voltages" used by Mr. Ali has its plain meaning as used in the context in which it appears, and it is used in a manner consistent with the use of this term in PJM's operational criteria documentation. Please refer to Section III of PJM Manual M-3, which is available at: http://pjm.com/directory/manuals/m03/index.html

d. and e. Please see the response to part c. Transource is not aware of any such instance.

Witness: Kamran Ali

Exhibit___(PJL-12)

OCA Statement No. 2

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.1 Please discuss when PPL's portion of the 230 kV transmission line between Conastone substation and Otter Creek substation ("the C-OC line") was most recently rebuilt.

A.1 Construction of the rebuild of PPL's section of the C-OC lines was completed in Q1 of 2017.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.2 Please confirm i) that the rebuilt PPL portion of the C-OC line carries one 230 kV circuit and has space on the transmission towers where a future transmission line could be connected, assuming appropriate attachment hardware, and ii) please describe such appropriate attachment hardware.

A.2 The structures of the rebuilt PPL portion of the C-OC carry one 230kV circuit and have space for a future transmission line.

To install the second circuit, three additional arms and insulator assemblies will need to be installed on the monopole structures. On the dead-end structures, three sets of dead-end insulator assemblies will need to be installed.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.3 Please confirm that the rebuilt PPL portion of the C-OC line has transmission towers with the structural capacity to support a second 230 kV transmission line using the same size conductors as are used in the existing transmission line. If not, please discuss why not.

A.3 The structures of the rebuilt PPL portion of the C-OC transmission line are designed to support a second 230kV transmission line using the same conductor as the currently installed circuit.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.4 Please describe the conductors that are used in the PPL portion of the existing C-OC line, and provide the summer normal rating and the summer emergency capacity for those conductors.

A.4 The rebuilt PPL portion of the C-OC line utilizes 1590 KCMIL 45/7 ACSR "Lapwing" conductor with a summer normal rating of 1626 Amps (647 MVA @ 230kV) and summer emergency rating of 2013 Amps (801 MVA @ 230kV). There is ability to utilize conductors with a higher capacity rating.

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.5 Please provide the summer normal capacity in MW and the summer emergency capacity in MW of the C-OC line prior to its most recent rebuild.

A.5 Prior to the rebuild of the C-OC line the 795 KCMIL 30/19 ACSR "Mallard" conductor had a summer normal rating of 1058 Amps (421 MVA @ 230kV) and a summer emergency rating of 1350 Amps (537 MVA @ 230kV). The capacity in MW is variable as it depends on both the line rating and the power factor of the circuit.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.6 Please provide the summer normal capacity in MW and the summer emergency capacity in MW of the existing C-OC line.

A.6 The existing C-OC line has a coordinated rating between PPL and BGE. The BGE portion of the C-OC line is the most limiting facility with a summer normal rating of 1224 amps (487 MVA @ 230kV) and a summer emergency rating of 1393 amps (554 MVA @ 230kV). The capacity in MW is variable as it depends on both the line rating and the power factor of the circuit.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.7 Please describe i) whether the portion of the C-OC line not owned by PPL has been rebuilt to conform with the configuration and the capacity of the rebuilt PPL portion, ii) if so, when this occurred, iii) if not, when it is expected to occur, and iv) when it occurs, what the summer normal and emergency ratings for the entire C-OC line will be.

A.7 PPL does not have information responsive to this data request.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.8 Please discuss when PPL's portion of the 230 kV transmission line between Graceton substation and Manor substation ("the G-M line") was most recently rebuilt.

A.8 The PPL portion of the G-M line rebuild was executed as two separate projects. The rebuild of PPL's portion of the G-M Line (excluding the 1.1 mile Susquehanna River crossing) was completed in Q4 of 2013. The 1.1 mile Susquehanna River crossing spans were reconductored in Q4 of 2017.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.9 Please confirm i) that the rebuilt PPL portion of the G-M line carries one 230 kV circuit and has space on the transmission towers where a future transmission line could be connected, assuming appropriate attachment hardware, and ii) please describe such appropriate attachment hardware.

A.9 The structures of the rebuilt PPL portion of the G-M line (excluding the 1.1 mile Susquehanna River crossing) currently has one 230kV circuit and has space to accommodate a future second 230kV circuit. To install the second circuit, four additional arms, one OPGW assembly, and three insulator assemblies will need to be installed on the monopole structures. On the dead-end structures, a second steel pole will need to be installed, as well three sets of dead-end insulator assemblies and OPGW dead-end assemblies.

The 1.1 mile Susquehanna River crossing portion of the G-M line does not have provision for a future 230kV line.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.10 Please confirm that the rebuilt PPL portion of the G-M line has transmission towers with the structural capacity to support a second 230 kV transmission line using the same size conductors as are used in the existing transmission line. If not, please discuss why not.

A.10 The structures of the rebuilt PPL portion of the G-M transmission line (excluding the 1.1 mile Susquehanna River crossing) are designed to support a second 230kV transmission line using the same conductor as the currently installed circuit. The 1.1 mile Susquehanna River crossing portion cannot accommodate an additional 230kV circuit in its existing configuration.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
<u>Docket No. A-2017-2640195 and A-2017-2640200</u>

Q.11 Please describe the conductors that are used in the PPL portion of the existing G-M line, and provide the summer normal rating and the summer emergency capacity for those conductors.

A.11 The rebuilt PPL portion of the G-M line (excluding the 1.1 mile Susquehanna River crossing) utilizes 1590 KCMIL 45/7 ACSR "Lapwing" conductor with a summer normal rating of 1626 Amps (647 MVA @ 230kV) and summer emergency rating of 2013 Amps (801 MVA @ 230kV). There is ability to utilize conductors with a higher capacity rating.

The reconductored 1.1 mile Susquehanna River crossing span of the G-M line utilizes 1033 KCMIL 54/19 ACCR "Curlew" conductor with a summer normal rating of 1786 Amps (710 MVA @ 230kV) and summer emergency rating of 2106 Amps (838 MVA @ 230kV).

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
<u>Docket No. A-2017-2640195 and A-2017-2640200</u>

Q.12 Please provide the summer normal capacity in MW and the summer emergency capacity in MW of the G-M line prior to its most recent rebuild.

A.12 Prior to the rebuild of the G-M line the 795 KCMIL 30/19 ACSR "Mallard" conductor had a summer normal rating of 1058 Amps (421 MVA @ 230 kV) and a summer emergency rating of 1350 Amps (537 MVA @ 230 kV). The capacity in MW is variable as it depends on both the line rating and the power factor of the circuit.

Witness: Phil Osei Penny

PPL Electric Utilities Corporation
Response to Interrogatories of
Office of Consumer Advocate, Set XII
Dated April 4, 2018
Docket No. A-2017-2640195 and A-2017-2640200

Q.13 Please provide the summer normal capacity in MW and the summer emergency capacity in MW of the existing G-M line.

A.13 The existing G-M line has a coordinated rating between PPL and BGE. The BGE portion of the G-M line is the most limiting facility with a summer normal rating of 1058 Amps (421 MVA @ 230kV) and a summer emergency rating of 1350 Amps (537 MVA @ 230 kV). The capacity in MW is variable as it depends on both the line rating and the power factor of the circuit.

Exhibit___(PJL-13)

OCA Statement No. 2

Application of Transource Pennsylvania LLC
Independence Energy Connection-East Project
Docket Nos. A-2017-2640195 and A-2017-2640200

Interrogatories of the Office of Consumer Advocate
Set XI
(Responses dated 5/23/2018)

Data Request 07:
The PP&L portion of a 230 kV transmission line running from Conastone to Otter Creek was recently rebuilt with available tower space for a second 230 kV transmission line that, if built, would roughly follow the proposed Furnace Run to Conastone double circuit 230 kV transmission line. i) Please discuss what consideration was given, by the Company and/or by PJM, to the suitability of a new second Conastone to Otter Creek 230 kV transmission line, using the rebuilt towers on the PP&L portion of the line, as an alternative to all or part of the proposed Furnace Run to Conastone double circuit 230 kV transmission line and associated substation facilities, and ii) if not considered, please discuss why not.

Response:
The system enhancement cited in OCA XI-7 was not submitted as part of PJM's solicitation process and therefore has not been evaluated by PJM.

Witness: Paul F. McGlynn

Application of Transource Pennsylvania LLC
Independence Energy Connection-East Project
Docket Nos. A-2017-2640195 and A-2017-2640200

Interrogatories of the Office of Consumer Advocate
Set XI
(Responses dated 5/23/2018)

Data Request 08:
The PP&L portion of a 230 kV transmission line running from Graceton to Manor was recently rebuilt with available tower space for a second 230 kV transmission line that, if built, would roughly follow the direction of the proposed Furnace Run to Conastone double circuit 230 kV transmission line. i) Please discuss what consideration was given by the Company and/or by PJM, to the suitability of a new second Graceton to Manor 230 kV transmission line, using the rebuilt towers on the PP&L portion of the line, as an alternative to all or part of the proposed Furnace Run to Conastone double circuit 230 kV transmission line and associated substation facilities, and ii) if not considered, please discuss why not.

Response:
The system enhancement cited in OCA XI-8 was not submitted as part of PJM's solicitation process and therefore has not been evaluated by PJM.

Witness: Paul F. McGlynn

Exhibit___(PJL-14)

OCA Statement No. 2

Application of Transource Pennsylvania LLC
Independence Energy Connection-East & West Projects
Docket Nos. A-2017-2640195 and A-2017-2640200

Interrogatories of the Office of Consumer Advocate
Set XVII
(Responses dated 6/12/2018)

Data Request 01:
Starting on page 16 of his direct testimony, Transource witness Paul McGlynn describes the process by which PJM determines new transmission upgrades that may result in economic benefits:

a. During PJM's initial analyses of the AP South Interface congestion, prior to the selection of Transource's Project 9A, please describe whether PJM evaluated the existing transmission infrastructure in the Project 9A project area to determine whether existing transmission infrastructure could be upgraded/reconductored/rebuilt in order to address the congestion issue. If so, please describe in detail the studies and/or analyses that were performed in this regard and provide copies of all documentation relating to same.
b. If the answer to the above is no, please explain in detail why such existing infrastructure was not so examined.
c. Does PJM maintain a current inventory of all transmission lines that have been built or rebuilt as double circuit lines and yet currently only have one set of conductors on one side? If so, please describe in detail how PJM uses such information in its planning processes. If not, please explain why PJM does not currently track such transmission lines?
d. During PJM's initial analyses of the AP South Interface congestion and the proposals submitted to PJM to mitigate that congestion, please describe the extent to which PJM developed and evaluated adjustments to and/modifications of the submitted proposals in order to maximize benefits, minimize costs, or otherwise improve one or more of the proposals.

Response:
a. Yes. Out of the 93 proposals received during the 2014/2015 Long-Term Window, 35 were primarily proposals to upgrade existing facilities. Regarding specifically the 41 proposals addressing the congestion on the AP South Reactive Interface, four of these were primarily proposals to upgrade existing facilities. In October of 2015, the PJM Board approved the construction of 11 upgrade proposals. Four of these were in Southern Pennsylvania or Northern Maryland, in the vicinity of Transource's Project 9A proposal.

   Additionally, in February of 2016, the PJM Board approved an optimized set of capacitor bank installations at existing substations, specifically to help address congestion on the AP South Reactive Interface. Several of the proposals to address congestion on the AP South Reactive Interface, including the 9A proposal, had capacitor bank components. PJM deemed it appropriate to remove these components from their respective proposals and consider them separately.

Even after all these upgrades to existing facilities were approved by the PJM Board and incorporated into PJM's baseline models, there remained sufficient congestion to warrant the consideration of additional greenfield proposals. Transource' s Project 9A proposal performed so well relative to the other proposals that PJM deemed it appropriate to analyze some of the remaining proposals (including proposed upgrades to existing facilities and certain other greenfield projects) in combination with the "East Line" element from Project 9A, as described in Mr. McGlynn's testimony on pages 26- 31. One of these remaining finalists, proposal 18H (as modified by PJM) was a proposal to upgrade existing facilities. PJM's modification of the original 18H proposal enhanced that proposal's performance as compared to the configuration that was originally submitted to PJM. In the end, Transource's Project 9A proposal outperformed all the combinations of the proposals that PJM evaluated and was approved for construction by the PJM Board.

In parallel with PJM's analysis of the alternatives proposed by stakeholders submitted during the 2014/15 Long-term Proposal Window, PJM did not conduct analysis of other hypothetical projects that were not proposed by any stakeholder. Please also refer to the Company's response to subsection d. PJM's planning analysis included both a review of approved reliability-based enhancements or expansions to determine whether acceleration or expansion of these project's scope could relieve congestion on the AP South Reactive Interface. Consistent with existing practices, PJM's analysis also ensured the final configuration of the selected projects was compliant with all reliability criteria.

Information about PJM's evaluation of the modified proposals described in Mr. McGlynn's testimony pages 26-31 is available at the PJM TEAC's website and is included in the following TEAC meeting presentations:

Combination Project Evaluation - TEAC Presentations:

- November 5, 2015 TEAC Meeting: [http://pjm.com/-/media/committees-groups/committees/teac/20151105/20151105-market-efficiency-update.ashx]

- December 3, 2015 TEAC Meeting: [http://pjm.com/-/media/committees-groups/committees/teac/20151203/20151203-market-efficiency-update.ashx]

- March 10, 2016 TEAC Meeting: [http://pjm.com/-/media/committees-groups/committees/teac/20160310/20160310-market-efficiency-update.ashx]

- April 7, 2016 TEAC Meeting: [http://pjm.com/-/media/committees-groups/committees/teac/20160407/20160407-teac-market-efficiency-update.ashx]

- May 12, 2016 TEAC Meeting: [http://pjm.com/-/media/committees-groups/committees/teac/20160512/20160512-market-efficiency-update.ashx]

- June 9, 2016 TEAC Meeting: [http://pjm.com/-/media/committees-groups/committees/teac/20160609/20160609-market-efficiency-update.ashx]

- "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board PJM", PJM Staff Whitepaper, August 2016: [http://pjm.com/-/media/committees-groups/committees/teac/20160811/20160811-board-whitepaper-august-2016.ashx]

Evaluation of Capacitors - TEAC Presentations:

- January 7, 2016 TEAC Meeting: [http://pjm.com/-/media/committees-groups/committees/teac/20160107/20160107-market-efficiency-update.ashx]

- February 22, 2016 TEAC Meeting: [http://pjm.com/-/media/committees-groups/committees/teac/20160211/20160211-market-efficiency-update.ashx]

b. See response to OCA-XVII-1-a.

c. PJM does not maintain a list of "all transmission lines that have been built or rebuilt as double circuit lines and yet currently only have one set of conductors on one side." Each transmission owner retains an inventory of its respective transmission lines and existing circuit configurations. PJM works with transmission owners to obtain existing circuit configurations when its planning responsibilities require it to do so.

d. See response to OCA-XVII-1-a.

   Under PJM's RTEP process, PJM has the ability modify proposals to enhance their performance, to evaluate certain aspects of proposals in isolation, or to combine aspects of multiple proposals. PJM exercised this ability in the evaluation of the 2014/2015 Long Term Window proposals, and properly determined that Project 9A was the most effective proposal to address the Market Efficiency needs in this area. PJM also evaluated in this context the possibility of accelerating or expanding the scope of approved reliability-based projects to relieve congestion on the AP South Reactive Interface.

Witness: Paul F. McGlynn