Comments to the DOE Federal Register Notice of Inquiry (NOI) on Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

Final Addendum – Additional Comments Received after March 9, 2006

The following material comprises the addendum to the comments received by DOE in response to the *Federal Register* Notice of Inquiry [FR Doc. E6–1394] issued on February 2, 2006. This notice solicited comment and information from the public concerning its plans for an electric transmission congestion study and possible designation of National Interest Electric Transmission Corridors (''NIETCs'') in a report based on the study pursuant to section 1221(a) of the Energy Policy Act of 2005. Through this Notice of Inquiry, DOE invited comment on draft criteria for gauging the suitability of geographic areas as NIETCs and announced a public technical conference concerning the criteria for evaluation of candidate areas as NIETCs.

DOE presents the comments as received and without any endorsement of their validity. The comments are listed in alphabetical order by commenter, including the date and time that the comments were received.

Comments received in Word format through 5:00 p.m. on March 9, 2006, are currently available at http://www.oe.energy.gov/energy_policy/epa_sec1221.htm#noi.

List of Commenters (including date and time the comments were received):
Note: Comments can be accessed by clicking on the page numbers listed to the right below

1. Hydro-Québec TransÉnergie, Received Mon 3/27/2006 1:29 PM

Hydro-Québec TransÉnergie's Comments

On the
DOE Federal Register Notice of Inquiry (NOI) on Considerations for transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

Hydro-Québec TransÉnergie ("TransÉnergie") is the transmission division of Hydro-Québec, a government-owned utility. TransÉnergie operates the most extensive transmission system in North America, and delivers high quality power to its customers in Québec, other parts of Canada and in the United States. Its system comprises over 32,500 km of lines, 18 interconnections and more than 500 transmission substations. TransÉnergie's customers purchase transmission services to serve the native load or to wheel out or wheel through the power grid. The main customers are Hydro-Québec Distribution, the load serving entity for the province of Québec and generators and power marketers for point-to-point service.

TransÉnergie's system is not synchronized with the adjacent systems as it is interconnected through either direct current or radial ties. Its has a total export capacity of 6,925 MW (4,430 MW to the U.S.) and an import capacity of 9,575 MW (2,870 MW from the U.S.). These facilities have allowed a long history of regular electricity exchanges with the U.S. Northeast, mostly with New England and the State of New York.

TransÉnergie appreciates the opportunity to comment on the department of Energy's Notice of Inquiry on Considerations for Transmission Congestion Study and Designation of national Interest Electric Transmission Corridors ("NIETCs").

The North American Electrical system is characterized by its international nature with a long history of electrical energy exchanges. The Energy Policy Act of 2005 confirms this international nature by the creation of the Electric Reliability Organization ("ERO"), which will be responsible for mandatory reliability Standards common to both the U.S. and Canada. TransÉnergie therefore needs to comment that Draft Criterion 4, "Targeted actions in the area would enhance the energy independence of the United States" is inappropriate when exchanges of electrical energy between Canada and the U.S. are concerned. On the contrary, designation of a NIETC should act in favour of higher volumes of electrical energy exchanges for reliability and economic benefits.

Constraints on adjacent and beyond adjacent systems prevent the full use of TransÉnergie's interconnections with the U.S. Solving such bottlenecks should not only be prioritized in terms of their impact on the U.S. grid, but also on the system as a whole. This should lead to a more optimal development of the North American system and a more optimal use of resources to the benefit of system reliability, customers and the environment.

A first issue is the use of the existing main interconnection between TransÉnergie and the State of New York (line 7040). TransÉnergie offers an export capacity of 1,800 MW over this interconnection while the New York Independent System Operator ("NYISO") normally limits deliveries to 1,500 MW (1,200 MW for deliveries to New York State and 300 MW for wheel through to other adjacent systems). Furthermore, this export capacity from Québec could be increased to 2,300 MW with the addition of transformation on TransÉnergie's system.

A second similar issue is the use of the main interconnection between TransÉnergie and new England (HVDC interconnection) which has a nominal capacity of 2,000 MW for exports to New England. Receptions in New England are often limited to 1,450 MW.

Those two interconnections therefore show a large potential for increases in imports capacities in the U.S. and should qualify as NIETCs.

TransÉnergie supports efforts to make the North American transmission grid more efficient for reliability and for economic effectiveness. The DOE effort will be more beneficial if it is undertaken with a broader view that takes into account the international nature of the North American system and includes international interconnections as potential NIETCs.

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2. Innovation Investments, Received Wed 5/10/06 7:27 PM

INNOVATION INVESTMENTS

May 10, 2006

Innovation Investments is today submitting these comments to the US Department of Energy (DOE) on the provisions in Section 1221 of the Energy Policy Act of 2005 regarding “national interest electric transmission corridors”, or NIETCs. Given DOE’s responsibility for the implementation of this section, we wish to make the DOE aware of the importance of taking into account wind energy on certain Native American Reservations in establishing the criteria under which NIETCs will be designated, and in deciding upon which corridors will receive this designation.

Innovation Investments (Innovation) is a developer of wind generation. We own the rights to many hundreds of acres of prime wind development areas on the reservations of several Indian tribes in the upper Midwest, and we have interests in wind projects in a number of other areas. The unique size of each reservation allows a NIETC to be utilized from a single geographic area.

As the DOE knows, the Energy Policy Act of 2005 requires the Secretary of Energy to conduct a nationwide study of electric transmission congestion and issue a report in which the Secretary may designate certain geographic areas as National Interest Electric Transmission Corridors

(NIETCs). As the DOE also knows, the designation of a NIETC will depend on several factors, including whether:

- the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity;
- the economic growth in the corridor, or the end markets served by the corridor, may be jeopardized by reliance on limited sources of energy; and a diversification of supply is warranted;
- the energy independence of the United States would be served by the designation;
- the designation would be in the interest of national energy policy; and
- the designation would enhance national defense and homeland security.

Several utilities and regional transmission organizations have already applied for "early designation" of certain transmission pathways as NIETCs.

Innovation recommends that DOE give particular consideration to potential wind resources when setting the criteria under which NIETCs will be designated. This recommendation is based on several factors, including:

- Wind resources will help meet several goals stated in the criteria required for the DOE to designate NIETCs.
  - They are a source of reasonably priced electricity that will support economic growth
  - They provide a diversification of power supply that will minimize the potential for disruptions
  - They support the energy independence and security of the United States
  - They serve the interest of national energy policy, which supports renewable resources and a cleaner environment

- Wind resources, although a preferable source of power, have to be sited in areas of adequate wind power, which are often as result of permitting very far from load centers and therefore require extensive transmission construction to get power to market.

- Wind is a growing area of generation investment and a streamlined transmission access process will encourage the development of this renewable, alternative source of energy.

Below, we elaborate on several of these factors. As mentioned above, in light of these considerations, we request that DOE give special consideration to wind resources in the criteria for and the designation of NIETCs.

The cost of wind energy at the busbar, including both capital and variable costs, on a levelized basis, is now comparable in a number of cases to that of power from new conventional power plants. The major cost component for a wind resource is the up-front capital cost required to install the facility. Once installed and operational, wind generation has very little variable cost. It has zero fuel and emission costs and low operation and maintenance costs. The levelized cost of wind generation is more than competitive with peaking and intermediate power, and in some cases can compete well with base load coal generation without the negative environmental emissions. Therefore, power from wind generation is reasonably priced and not subject to the volatility observed in power produced from fossil fuel generators. While economic, getting wind power to market is an issue with which the DOE can assist greatly through NIETC designation.

Wind resources also help diversify the power supply mix for the markets in which they operate. Most power markets are dominated by fossil fuel, hydro and nuclear generation plants. Wind generation is currently less than 1 percent of total electricity produced in the country. Therefore the introduction of wind generation resources in virtually any power market in the country serves to diversify the power supply mix. This diversity clearly reduces the exposure of customers to the volatility of fuel prices, as we have seen the price of natural gas and coal escalate sharply in recent years and months (oil is used to a very limited extent in power generation, but when used, also increases the price of power). This diversity could help consumers with managing their energy expenditures, which escalated sharply this past winter, and help make American businesses more competitive.

In addition, wind energy contributes to the energy security of the United States. Wind is an inexhaustible domestic resource. To the extent that the United States uses fuels imported from foreign countries to produce its energy, it remains dependent on these countries. An increase in wind capability will reduce dependence on fossil fuels and subsequently dependence on the countries from which these fuels are imported, making the United States more energy independent.

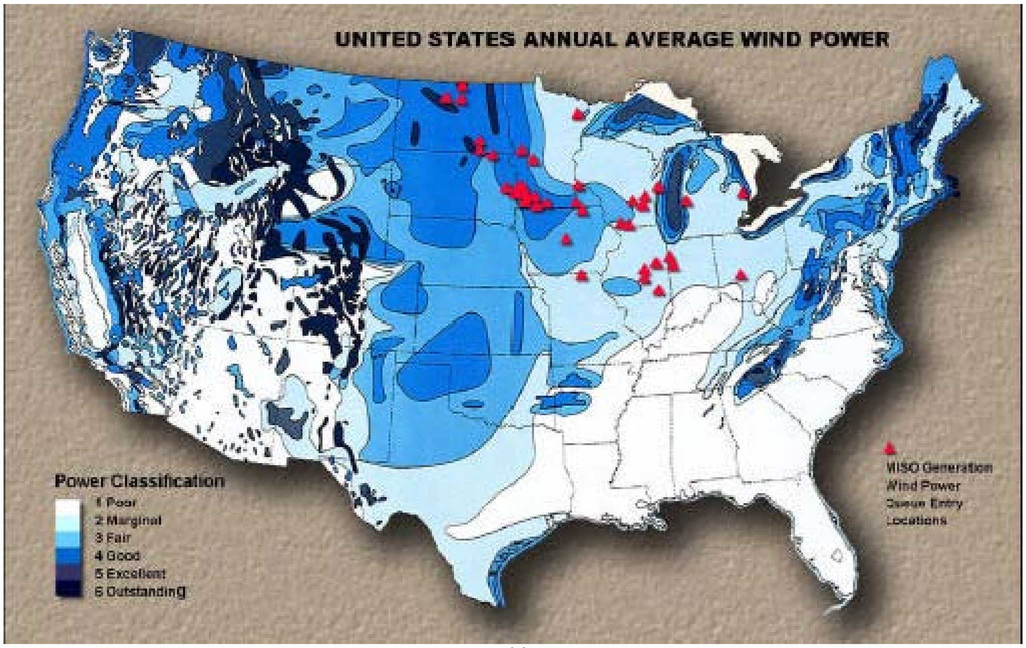
Further, wind generation serves the interest of national energy policy. The United States National Energy Policy[1][1] document highlights "reliable, affordable, and environmentally sound energy for America's future." According to the President of the United States, "America must have an energy policy that plans for the future, but meets the needs of today." Wind energy is an energy source that, in its entirety, embodies these ideals. It is reliable, affordable and environmentally sound. An added advantage of wind power, as mentioned above, is that it is a domestic resource. Policies that promote the development of wind resources simultaneously support the national energy policy.

Despite its many advantages, however, wind energy suffers from a severe limitation peculiar to few sources of energy – it lacks the siting flexibility available to many other sources of energy. Wind resources must be constructed in areas where there is adequate wind supply, which is often very far from load centers. To deliver the power to market, therefore, developers must construct transmission lines over long distances. This is a challenge due to hurdles that include the acquisition of rights-of-way and regulatory, environmental and other permits.

The hurdles to transmission construction can be reduced with the designation of NIETCs. Without such designations, it may be impossible, or at best extremely burdensome, to obtain transmission paths for some of the favorable wind resources. This will severely restrict the development of these resources. For example, Exhibit 1 below shows areas in the United States where significant wind power is available to produce electricity. As shown, a large number of the preferable wind sites in the Midwest are located in the Dakotas. Some of the load centers that could be served by generation resources in these areas include the Minneapolis-St. Paul area in Minnesota and the Chicago area in Illinois. To serve these load centers, long transmission lines will have to be built to connect the wind power sources to the existing grid, which could involve acquisition of rights-of-way and permits in several different States. This could result in only incremental development of these power sources.

[1] National Energy Policy, Report of the National Energy Policy Development Group, May 2001.

Exhibit 1: Annual Average Wind Power in the United States



Source: Midwest ISO

Finally, wind is a growing area of generation investment that must be encouraged through the establishment of a streamlined transmission access process. The American Wind Energy Association estimates that the total wind capacity in the United States increased from approximately 1,700 MW in 2001 to more than 9,000 MW in 2005. In 2006 the capacity is expected to exceed 12,000 MW, and by 2020 wind energy may be capable of supplying 6 percent of the country's electricity demand. Transmission will be crucial to realizing the full potential of wind generation. Therefore it is important to reduce the barriers to transmission access so that the full potential of this important renewable domestic resource may be realized.

The development of wind resources will benefit consumers, contribute to national security and the energy independence of the country, and serve the interest of the national energy policy. We therefore strongly encourage the Department of Energy to consider potential wind resources and their satisfaction of many of the factors in the Energy Policy Act during the setting of the criteria for and the designation of NIETCs.

3. New Jersey Board of Public Utilities, Received Fri 3/10/06 3:06 PM

UNITED STATES OF AMERICA

BEFORE THE

DEPARTMENT OF ENERGY

Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors (EPACT 1221 Comments)	**Notice of Inquiry**

COMMENTS OF THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

On February 2, 2006, the Department of Energy's ("DOE") Office of Electricity Delivery and Energy Reliability issued a Notice of Inquiry ("NOI") requesting comment and information concerning its plans for an electricity transmission congestion study and possible designation of National Interest Electric Transmission Corridors ("NIETC"), as required by section 1221(a) of the Energy Policy Act of 2005 ("the Act").

The New Jersey Board of Public Utilities ("NJBPU") is the administrative agency charged under New Jersey law with the general supervision and control over all public utilities in the State, including electric utilities and their rates and service.[1] Because additional capital investment in new transmission capacity may affect ratepayers in New Jersey, the NJBPU has a significant interest in the DOE's congestion study and potential designation of NIETCs. The comments of the NJBPU are set forth below.

[1] N.J.S.A. 48:2-13; N.J.S.A. 48:2-21.

I. Suggested Criteria For Transmission Congestion Study

The Act requires the Secretary of Energy to conduct a nationwide study of electric transmission congestion, and issue a report based on the study which may designate certain geographic areas experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers as an NIETC. In exercising its discretionary authority under the Act to designate NIETCs, the Secretary of Energy may consider: (a) the economic vitality and development of the corridor, or the end markets served by the corridor, may be constrained by lack of adequate or reasonably priced electricity; (b) the economic growth in the corridor or the end markets served by the corridor may be jeopardized by reliance on limited sources of energy, and whether diversification of supply is warranted; (c) the energy independence of the United States would be served by the designation; (d) the designation would be in the interest of national energy policy; and (e) the designation would enhance national defense and homeland security.

The NJBPU urges the Secretary of Energy to evaluate, at a minimum, all of the factors listed above when designating an NIETC, even though the Act seems to give the Secretary discretionary authority to consider less than all of these criteria. These criteria provide the appropriate basis to evaluate geographic areas for NIETC designation. The use of all these criteria will allow the Secretary of Energy to properly evaluate whether congestion in the transmission system impedes economically efficient electricity transactions that threaten the system's safe and reliable operation. In addition, we urge the Secretary of Energy to perform this evaluation in the context of an alternative analysis as referenced below in item VII, in order to consider real reductions in load from advanced demand side programs. Finally, we urge the

Secretary to create as transparent a process as possible in designating NIETCs, and to significantly utilize state input in its decision making process.

II. The DOE Should Define NIETCs Broadly

The DOE asks commentators to address the breadth of potential NIETC designations. The NJBPU urges the DOE to define these corridors broadly, designating them on a geographic basis which will provide the states and the DOE with maximum flexibility to site the actual transmission line in the most effective and efficient manner that balances competing interests. A corridor that takes into account a larger geographic region, for example, will better allow the transmission line to avoid or minimize impacts upon populated areas, environmentally sensitive areas, parks, and other potentially troublesome areas. A narrow corridor, on the other hand, would limit the actual siting location of the transmission line, and may require the line to run through sensitive areas—thereby increasing the likelihood of public opposition and unnecessary impact upon the State.

Siting is particularly difficult in New Jersey and other densely populated states. Urban/densely populated areas like New Jersey are geographically different from large, wide open areas like the Rocky Mountain region of the country—a twenty mile stretch of land in states that comprise the Mid-Atlantic/Northeast part of the country is comparable to 500 miles of land in the western part of the United States. A wider corridor will provide the DOE with more flexibility to site the transmission line in the most unobtrusive way. We therefore agree with the DOE that defining corridors too narrowly would unduly restrict authorities, including state agencies, FERC and other relevant parties charged with determining whether and how to authorize the siting for construction and operation of transmission facilities to relieve identified congestion.

The NJBPU therefore supports the expectations of Secretary of Energy that the identification of corridors should be generalized electricity paths between two or more locations, as opposed to specific routes for transmission facilities. In fact, New Jersey supports this concept being applied more broadly to define transmission corridors to relieve either physical or contractual congestion on the transmission system by geographic regions.

III. The DOE Should Clearly Define Persistent and Dynamic Congestion

The DOE asks whether it should distinguish between persistent congestion and dynamic congestion. However, the DOE does not define either of these terms in the NOI. A quick review of existing studies and documents does not provide universal definitions of these terms and they are not used in the usual course of business. Therefore, the NJBPU requests that the DOE define these terms before accepting comments on whether they should be distinguished.

IV. The DOE Should Distinguish Between Physical and Contractual Congestion when Designating NIETCs

The DOE asks whether it should distinguish between physical congestion and contractual congestion, and if so, how? There is, indeed, a distinction between physical congestion and contractual congestion, and therefore the NJBPU believes the NIETC designation process should reflect this difference. The NJBPU submits that both impact the transmission system and may affect its safe and reliable operation, including the ability for consumers to receive reasonably priced electricity.

The basis for the distinction between physical congestion and contractual congestion should focus on whether the congestion is a reliability problem (i.e., a supply deliverability problem) or a contractual pricing problem, (i.e., consumers are exposed to high congestion costs). Once the type of congestion problem is determined, the appropriate corridor and transmission fix can be identified. As far as the importance of the distinction between physical and contractual congestion, the NJBPU believes that other factors should be considered, including: (1) characteristics of the geographic region impacted by either type of congestion; (2) the lack of generation resources; and (3) the price of electricity in the region. In other words, there should not be a "one size fits all" approach for the entire country because different geographic regions have different characteristics and needs.

However, there is one feature that both physical congestion and contractual congestion have in common. Once the appropriate transmission fix has been determined, the barriers impacting the actual regulatory siting process of the transmission solution are the same. The fact that the DOE will have the ability to designate NIETCs for both physical congestion and contractual congestion could allow for a more streamlined solution to modernizing our nation's transmission system.

V. The DOE Should Review the Respective RTO/ISO Transmission Plans and Studies.

The DOE asks what existing transmission studies and other plans should be reviewed and how far back the Department should look when reviewing transmission planning and path flow literature. The DOE should review, at a minimum, the transmission plans and studies performed by the regional transmission operators ("RTOs") and independent transmission operators ("ISOs") in their respective areas. Since the RTOs/ISOs are responsible for the reliability of the transmission grid, including the constant modeling and evaluation of system flows on their respective transmission systems, they are in the best position to provide detailed and accurate information regarding the transmission improvements required to maintain a reliable electric system. Such studies often involve complex modeling of particular transmission systems as well as input from a variety of stakeholders and market participants. Therefore, we believe that the RTOs/ISOs are in the best position to understand the needed transmission system upgrades and other projects that can mitigate congestion constraints and reliability problems.

VI. The DOE Should Utilize All of its Draft Criteria, But Should Designate Draft Criterion 1 and 2 as the Most Important.

The DOE requests comment on what criteria it should use in evaluating the suitability of geographic areas for NIETC status. The NJBPU believes that the draft criteria proposed by the DOE will provide a well-balanced analysis for determining which areas should be designated as NIETCs. However, the NJBPU strongly urges that the DOE not use a "one size fits all approach" to the designation of NIETCs. The NJBPU strongly believes that, in its determination of NIETCs within New Jersey's region, Draft Criterion 1, *Action is needed to maintain high reliability*, and Draft Criterion 2, *Action is needed to achieve economic benefits for consumer* are the most important and should be weighed more heavily. This emphasis may be inappropriate in other regions of the country, however.

As stated by the DOE in its NOI, maintaining a reliable electric system is essential to any region's economic health and future development. The DOE needs only to look at the August 2003 blackout to recognize how important it is to maintain a reliable transmission system. In addition, the DOE recognizes that congestion in the transmission system impedes economically efficient electricity transactions, and the DOE has estimated that this congestion costs consumers several billion dollars per year.

Currently, New Jersey experiences higher electric costs in the PJM region than its neighboring PJM states. This is due partially to transmission siting issues, environmental regulations and the lack of newer and more efficient generation sources. New Jersey believes that while it may be our problem today, these very costs and reliability problems will surface and impact our neighboring states in the immediate future. It is our belief that the appropriate solution should be resolved on a regional basis, where the costs of such solutions are shared among the region. As such, New Jersey is now burdened with resolving what we feel is a regional problem locally, where New Jersey consumers are asked to pay more for electricity. This has created a cost inequity between New Jersey and the states within our region, and has the potential to impact New Jersey's economy. Without a reliable bulk transmission system providing reasonably priced electricity to New Jersey and the surrounding PJM region, the NJBPU could not carry out its duty to provide reasonably priced electricity to its consumers.

VII. The DOE should consider the potential for demand-side programs to reduce the need for new transmission.

The DOE also seeks comment on whether there are any other considerations that the DOE should consider in making an NIETC designation. While the NJBPU encourages the further development of a more robust transmission network that will enable customers to save money by reliably accessing more efficient generation than is possible with today's transmission system, the NJBPU is concerned that these new* lines will increase air emissions from the generators providing that lower cost power. In New Jersey alone, cost estimates of ground level ozone's contribution to respiratory illness total more than $59 million per year.[2] In New Jersey, exposure to fine particulate levels above the federal health standard results, each year, in an estimated 350 to 1,200 deaths, 6,000 emergency room visits, and 68,000 asthma attacks. The cost of these health impacts totals more than $1 billion every year. These externalities should not be left out of the analysis when determining the need for a NIETC designation.

The NJBPU submits that limiting demand, and in particular peak demand, can eliminate or lessen the need for new transmission lines and upgrades. Recent national reports have documented that demand side energy efficiency programs for electricity and natural gas, renewable energy programs, and demand side management programs can significantly lower the cost for energy by 20% and save consumers $15 billion per year in retail natural gas and electricity costs.[3] Customer demand for electricity is highly variable and therefore characterized by "peak periods." These peak periods require a greater amount of electric resources, including distribution, transmission, and generation assets to meet the peak demand. Consequently,

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[2] *Final Report of New Jersey Comparative Risk Project* (March 2003).
[3] ACEEE Impacts on Natural Gas Markets of Energy Efficiency and Renewable Energy Practices and Policies, 2003 (Updated 2005); Benefits of Demand Response in Electricity Markets, USDOE, Feb 2006.

reducing consumption of electricity during peak periods can decrease the costs and improve the overall efficiency of the electric system.

Moreover, market power in electric wholesale markets can be a concern during periods of tight supply and demand conditions. As demand increases, there are fewer alternative sources of generation, providing the higher cost generators an opportunity to bid above their variable cost and earn scarcity rents. Consequently, a reduction in demand during these peak periods could produce market efficiencies that flow to consumers through lower wholesale prices – and eventually through lower retail prices.

Before designating an NIETC, the DOE should perform an "alternative analysis," requiring that measures such as demand–side management be considered as an alternative or component to new transmission lines or upgrades. This integrated resource planning-type analysis should include both supply-side and demand-side measures such as load management for residential, commercial and industrial customers, new residential and commercial building energy codes, energy efficiency standards for appliances and existing homes and businesses, the use of distributive renewable energy systems, such as photovoltaic installations, and the use of renewable portfolio standards. Not only can this alternative analysis identify whether various policies can avoid all or some of the cost of the proposed transmission line or upgrade and the avoided environmental externalities of the line, it can also lead to savings from the reduction in the annual cost to the residents and businesses of the avoided energy use.

CONCLUSION

WHEREFORE, the NJBPU respectfully provides comments in this NOI.

Respectfully submitted,
Zulima V. Farber
Attorney General of New Jersey

By:______________________________
Kenneth J. Sheehan
Deputy Attorney General
On behalf of the New Jersey Board
of Public Utilities

Dated: March 9, 2006

4. Powerex, Received Fri 4/14/06 2:10 AM

13 April 2006

Office of Electricity Delivery and Energy Reliability, OE-20
Attention: EPACT 1221 Comments,
U.S. Department of Energy
Forestall Building, Room 6H–050,
1000 Independence Avenue, SW.,
Washington, DC 20585

Via email: EPACT1221@hq.doe.gov

Dear Ms. Agrawal:

Powerex Corp[1]. ("Powerex") respectfully submits the following comments in response to the Department of Energy's February 2, 2006 Notice of Inquiry. Powerex welcomes the

[1] Powerex Corp. is a corporation organized under the Company Act of British Columbia, with its principal place of business in Vancouver, British Columbia, Canada. Powerex is the wholly-owned marketing subsidiary of British Columbia Hydro and Power Authority ("BC Hydro"), a provincial Crown Corporation owned by the Government of British Columbia. Powerex sells power at wholesale in the United States pursuant to market-based rate authority originally granted by the Federal Energy Regulatory Commission.

opportunity to provide comments on the planned transmission congestion study and possible designation of National Interest Electric Transmission Corridors (''NIETCs''). We felt that it would be most helpful if Powerex focused its comments on to the Department of Energy's questions 3 and 4.

Question 3: Appendix A lists those transmission plans and studies the Department currently has under review. In addition to those listed in Appendix A, what existing, specific transmission studies and other plans should the Department review? How far back should the Department look when reviewing transmission planning and path flow literature?

The plans and studies that Powerex believes would help the Department understand congestion issues in the Pacific Northwest are already included in Appendix A:

- Section III. Documents or Data From the Western Interconnection,
  - Subsection 7. Available from Northwest Power Pool Web site (Northwest Regional Transmission Association reports).

We do, however, caution the Department about the inherent limitations to certain modeling techniques, e.g., production cost models, when it comes to identifying congestion. This is especially true with heavily loaded paths, bi-directional flow transmission corridors and transmission paths that are impacted by a number of factors including temperature, generation mix, industrial load volatility, river flows associated with various river basins, transmission maintenance schedules, etc. Modeled economics, such as production cost simulations, are not well equipped to reflect other than "normal" conditions which is why they cannot simulate real conditions and often do not identify path congestion. In short, we believe that some paths that are sensitive to multiple variables need extra attention in the form of collecting time-specific data. This should

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Powerex sells power from a portfolio of resources in the United States and Canada, including Canadian Entitlement resources made available under the Columbia River Treaty, BC Hydro system surplus resources, and various other power resources acquired from other sellers within the United States and Canada. Powerex also markets power in Canadian provinces other than British Columbia and in Mexico.

include the collection of correlated data sets that can help to reconstruct hours of constraint: such as temperature, local load, local generation, limiting contingency, limiting facility, market hub prices, water conditions, gas prices, etc.

In general, we believe it would be most helpful to review transmission planning and path flow studies that are current, but don't believe it is necessary at this time to have a rigid cut-off date for studies. In fact, as a supplement to the historical data that the Department may collect, we believe that the Department should initiate a data collection effort that covers the upcoming three years. This effort would require transmission path operators to record in addition to the hourly Operating Transfer Capability (OTC) limits, the limiting contingencies and limiting facility (which together contributed to the OTC limit that was set for the hour), operator actions required to stay within the new OTC limit (e.g. curtail schedules, arm Remedial Action Schemes, capacitor bypass, directed redispatch, phase shifter operation, etc.). This sort of effort would provide very detailed information on which facilities are repeatedly impacting system operations and may yield insight into the most cost effective ways of relieving real-time congestion.

Question 4: What categories of information would be most useful to include in the congestion study to develop geographic areas of interest?

A limitation of congestion measures that rely on real-time actual flow and hourly OTC data is their inability to account for the efforts of market participants to minimize their risk exposure to transmission curtailments. For instance, the real-time OTC for the WECC's Path 3 (Northwest - Canada) can have <u>huge</u> uncertainty and as a result market participants actively manage the risk of transmission curtailment. Consequently, actions taken days or hours in advance by market participants to reduce the risk of curtailment can result in unused capacity in the hour[2].

[2] Selling Entities who are unable to fulfill sales commitments because of transmission constraints ultimately pay the real-time market prices in the settlement of their obligations. The severe negative financial implications of real-time transmission curtailment often inspires caution when making forward or preschedule sales and as a result transmission may be left unused in real-time.

For the summer of 2003, Powerex spent a lot of time trying to forecast the impact of outages on the North-to-South OTC for Path 3 (Northwest-Canada, also known locally as the Northern Intertie). Ultimately we boiled the problem down to an optimistic forecast (e.g. 70F temperature and favorable Puget Sound Energy (PSE)/Seattle City Light (SCL) local generation) and a pessimistic forecast (e.g. 85F and unfavorable PSE/SCL local generation). When faced with such a wide range of uncertainty on the possible OTC, many market participants will adjust schedules in advance to minimize exposure to the real-time OTC risk. Figure 1, shown below, summarizes the range of uncertainty for minimum daily OTC as well as the actual minimum daily OTC that occurred in real-time. Powerex sees this as an example of historical congestion on Path 3 that would not be identified if only actual flow and real-time hourly OTC limits are considered.

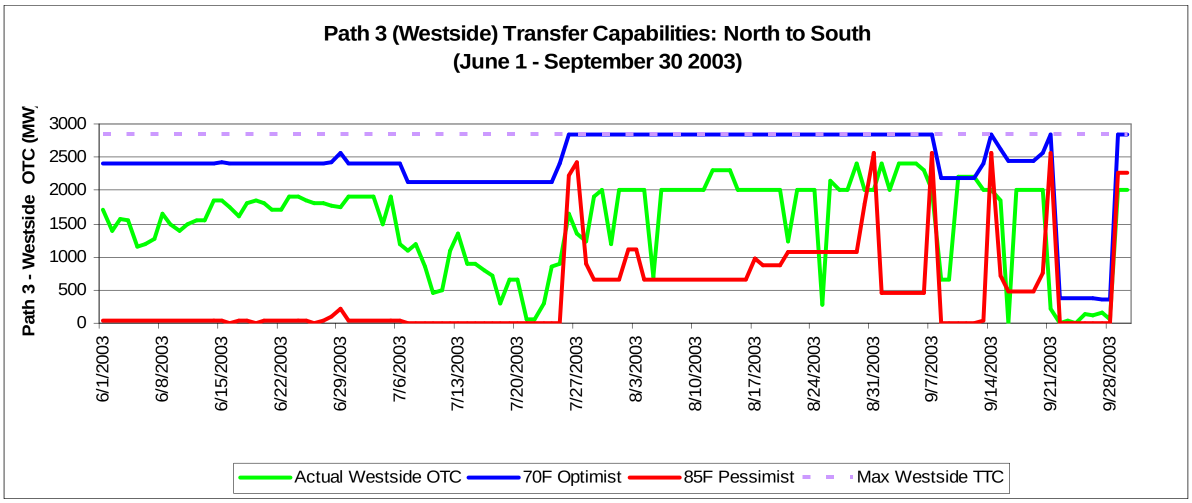

Figure 1: Forecast & actual minimum daily OTC limits for the Westside of Path 3

Another limitation of congestion measures that rely on real-time actual flow and hourly OTC data is their inability to account for operator action to prevent OTC limit violations. Our experience is that when schedules exceed a path's OTC limit, the path operators will curtail schedules to ensure that the limit exceedence will be resolved. After the fact, hours of curtailment often appear as hours when flows are below the OTC limits, and sometimes well below the OTC limit, because of the margin system operators build into the schedule curtailments as they strive to restore the transmission system to a reliable operating point.

Rather than after the fact flows, we believe that tracking intra-regional price spreads would be a more accurate after-the-fact measure of congestion. If power prices between regions were essentially equal in a given hour then it suggests that there was no transmission congestion in that hour.

Specifically in response to question 4, the categories of information that Powerex believes would be most useful in the congestion study include:

- Definitions for Transmission Paths and their associate maximum Path Ratings;
- Historical hourly Pre-schedule Transfer Capabilities (e.g. what the path limits were during pre-schedule time frames);
- Historical hourly real-time Path Operating Transfer Capabilities (e.g. what the path limits were in real-time);
- Historical data on regional market price indices or hubs;
- Historical data on the physical conditions that result in congestion (e.g. what are the worst contingencies and the most limiting facilities that together result in restrictions on the path rating); and,
- Historical outage data for critical contingencies that could cause congestion.

Going forward, e.g., for three years, Powerex believes that it would very useful to supplement historical information by collecting hourly data on the following:

- Hourly OTC limits on all constrained paths;
- Factors that set the OTC limits (e.g. the most limiting contingency and associated limiting facility for each hour on all constrained paths); and,
- System conditions at the time when OTC limits are exceeded (e.g., water conditions, market prices, temperature, local load and local generation);
- For hours when actual flow exceeded the hourly OTC:
    - the maximum exceedence (over OTC);
    - duration of the exceedence;
    - operator actions to restore the system to within operating limits.

Thank you for the opportunity to submit comments on the planned transmission congestion study and possible designation of National Interest Electric Transmission Corridors (“NIETCs”).

Respectfully submitted,

__/s/ Gordon Dobson-Mack____

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cc: Rob Kondziolka, Chair WCATF
Chris Reese, Chair NTAC
Doug Little, Chair TPAC

5. PSEG Companies, Received Thurs 3/23/06 3:03 PM

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

RE: Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors

COMMENTS OF THE PSEG COMPANIES

March 23, 2006

Public Service Electric and Gas Company (“PSE&G”), PSEG Energy Resources & Trade LLC (“PSEG ER&T”) and PSEG Power LLC (“PSEG Power”) (collectively referred to herein as the “PSEG Companies”) respectfully submit responsive comments in the above-referenced proceeding.

The PSEG Companies understand that, in its February 6, 2006 Notice of Inquiry,[1] the Department of Energy ("DOE") requested that comments regarding the "draft criteria for gauging the suitability of geographic areas as National Interest Electric Transmission Corridors" ("NIETCs") be submitted by March 6, 2006, and that no express provision was made for the submission of responsive or reply comments. The DOE also provided notice on February 6 of a technical conference on these issues to be held in Chicago, Illinois on March 29, 2006. While the PSEG Companies did not file written comments on March 6, 2006, they respectfully request that the DOE consider these responsive comments so as to complete the record and clarify certain significant misperceptions and inaccuracies created by certain of the comments filed on March 6. Specifically, the PSEG Companies will respond to the March 6 comments filed by PJM Interconnection, L.L.C. ("PJM"), American Electric Power Service Corporation ("AEP"), Allegheny Power ("Allegheny") and The City of New York ("City of New York").

The PSEG Companies submit that these sets of comments request premature consideration of particular projects for NIETC "early designation," and thereby effectively prejudge consideration of such projects by the Federal Energy Regulatory Commission ("FERC") as well as circumvent and prejudice established processes in PJM and in the New York Independent System Operator ("NYISO") for evaluation of transmission expansion projects. The PSEG Companies' concerns are driven by the belief that increasing demand for electricity should be met with the most cost-effective and efficient combination of supply alternatives, so that load in New Jersey does not ultimately bear the risk and cost of uneconomic transmission projects.

[1] "Consideration for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors," Notice of Inquiry and Request for Comments, 71 Fed. Reg. 5660 (February 2, 2006) ("NOI").

Thus, the PSEG Companies believe that the DOE should not accord early NIETC designation to the corridors described in the above-listed sets of comments, as such early designation has not been shown to be "necessary and appropriate" in accordance with the DOE's directive. The PSEG Companies would be pleased, and will be prepared, to expound upon their position at the DOE's March 29 technical conference.

In support of the foregoing, the PSEG Companies respectfully state as follows:

I.

DESCRIPTION OF THE PSEG COMPANIES

The PSEG Companies are each wholly-owned, direct and indirect subsidiaries of Public Service Enterprise Group Incorporated ("PSEG"). The principal and executive offices of PSEG are located at 80 Park Plaza, Newark, New Jersey 07102. PSEG is an exempt public utility holding company engaged in, among other things, the generation of electric energy, and the transmission, distribution and sale of electricity and natural gas through its subsidiaries.

PSE&G is a public utility company organized under the laws of the State of New Jersey. PSE&G is presently engaged in, among other things, the transmission and distribution of electricity and the distribution of natural gas in New Jersey. PSE&G owns transmission facilities in PJM.

PSEG Power is a wholesale energy supply company that integrates its generation asset operations with its wholesale energy, fuel supply, energy trading and marketing, and risk management functions through three principal subsidiaries: (i) PSEG Nuclear LLC, which owns and operates nuclear generating stations; (ii) PSEG Fossil LLC, which develops, owns and operates domestic fossil-fired and other non-nuclear generating stations, and (iii) PSEG ER&T.

PSEG ER&T, a direct subsidiary of PSEG Power, sells power and energy and certain ancillary services at market-based rates. PSEG ER&T markets the capacity and production of

PSEG Nuclear's and PSEG Fossil's generating stations, manages the commodity price risks and market risks related to generation, and provides gas supply services. PSEG ER&T is engaged in extensive asset-based energy trading operations throughout the Northeast and in the Midwest.

II.

BACKGROUND

On August 8, 2005, the Energy Policy Act of 2005, Public Law 109-58 ("the EPAct") became law. Subsection 1221(a) of the EPAct amends the Federal Power Act by adding a new Section 216, which requires the Secretary of Energy to (i) conduct a nationwide study of electric transmission congestion; and (ii) issue a report based on the study in which the Secretary may designate "any geographic area experiencing electric transmission capacity constraints or congestion that adversely affects consumers as a national interest electric transmission corridor." 119 Stat. 594, 946-53 (2005). On February 2, 2006, the DOE issued a Notice of Inquiry and Request for Comments ("NOI"), in which it explained its intent to "identify corridors for potential projects as generalized electricity paths between two (or more) locations, <u>as opposed to specific routes for transmission facilities</u>." NOI, at 5661 (emphasis added). In this regard, the DOE noted its belief that "defining corridors too narrowly would unduly restrict state authorities, FERC, and other relevant parties in determining whether and how to authorize the construction and operation of transmission facilities to relieve the identified congestion." <u>Id</u>. In the NOI, the DOE solicited feedback regarding how to "consider and define corridors" and how to develop and apply criteria to "evaluate" geographic areas identified in the Secretary of Energy's congestion study. <u>Id</u>. at 5661-62. Finally, the NOI furnished the opportunity to "interested parties" to identify "geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC"; such parties would need to present a "particularly compelling case" that early designation as a NIETC is "both necessary and appropriate." Id. at 5661.

In comments filed on March 6, 2006, PJM, AEP, Allegheny and The City of New York have effectively requested early NIETC designation of particular projects. The PSEG Companies will not at this time argue the merits of the various projects discussed in these comments, since the projects have not been evaluated through the respective RTO processes to (1) determine if there is a need for these projects; and (2) assuming such a need exists, determine whether the projects represent the most cost-effective solutions. It is critically important that the DOE refrain from acting precipitously or prematurely with regard to these projects. As the PSEG Companies will fully explain herein, to do so would in fact "unduly restrict FERC and other relevant parties" by preventing a full, reasoned and careful selection process, circumventing ongoing FERC proceedings and ignoring PJM's own Tariff processes. Congress' desire to have transmission infrastructure built where needed and appropriate should not cloud the DOE's judgment and cause the DOE to act in an unduly hasty manner.

III.

DISCUSSION

PJM Comments

In its comments filed in this proceeding, PJM seeks early designation of two (2) NIETCs within the PJM region – the Allegheny Mountain path and the Delaware River path, and seeks such early designation "at the earliest possible date and no later than December 31, 2006." PJM Comments, at 3. While PJM is careful to state in its comments that it is "not seeking DOE designation of a particular line or particular facilities," id. at 42, the entire thrust of the comments is to promote for DOE consideration two "significant new long-distance transmission lines, both proposed by large, established transmission companies," which coincidentally will be built on "routes that traverse the Allegheny Mountain path and/or the Delaware River path." Id. at 43. Thus, while the NOI only sought information from the public regarding the early designation of particular transmission corridors, PJM has taken this request one step further by actually mentioning, and espousing the merits of, two specific projects – a 765 kV line project proposed by AEP that cuts across both paths and a 500 kV line project proposed by Allegheny that traverses the Allegheny Mountain path. PJM in fact characterizes these proposals as "specific" and "serious," representing "independent, objective evaluations from those willing to commit capital …." Id.

The PSEG Companies submit that PJM's approach is flawed for at least three fundamental reasons. First, neither the AEP project nor the Allegheny project has been considered, modified and/or approved by PJM's own Regional Transmission Expansion Planning ("RTEP") process.[2] This existing regional planning process is intended to "consolidate the transmission needs of the region into a single plan which is assessed on the basis of maintaining the reliability of the PJM Region in an economic and environmentally acceptable manner and supporting competition in the PJM Region." PJM Operating Agreement, Schedule 6, Section 1.4(a). This robust process, which has resulted in approximately $1.327 billion in transmission projects (baseline reliability upgrades) being approved by the PJM Board, encompasses planning for both reliability projects and those needed to "support competition." As PJM states in its subject comments, the "RTEP process evaluates reliability, operational performance and economic factors and openly elicits, accommodates and integrates all market-based solutions to all planning issues – new generation of all types and sizes, A.C. and D.C. merchant transmission, and demand response programs." PJM Comments, at 41.

[2] The RTEP process is formally designated as Schedule 6 of the Amended and Restated Operating Agreement of PJM, Third Revised Rate Schedule FERC No. 24.

Under the current PJM RTEP economic expansion process, as codified in PJM's FERC-approved Tariff, PJM's "objective" is to "provide cost-effective transmission solutions to alleviate congestion" on the PJM system which "cannot be hedged by the use of FTRs or other hedging instruments available … and that no market participant or other entity otherwise has proposed to resolve." Schedule 6 of PJM Operating Agreement, Section 1.5.7(a). Specifically, when PJM determines that "sufficient" unhedgeable congestion exists on the system (which determination is made when the cumulative monthly unhedgeable congestion associated with a constraint exceeds an applicable threshold), PJM then posts on its Internet site a notice advising that it "shall immediately commence an initial cost-benefit analysis of potential transmission enhancements or expansions that would relieve the applicable transmission constraint." Id. at Section 1.5.7(d). The market then has a one-year "window" within which to propose market-based solutions to the unhedgeable congestion identified. If this window closes and no market-based response to the unhedgeable congestion has been proposed, then PJM "shall propose to include in the [RTEP] a cost-effective transmission enhancement or expansion … to resolve the unhedgeable congestion." Id.[3]

Thus, under the currently-effective FERC-approved PJM RTEP process, PJM (i) determines whether sufficient "unhedgeable" congestion exists; (ii) conducts a cost-benefit analysis of potential economic transmission enhancements; (iii) allows a one-year market window to permit market-driven solutions – transmission, generation and/or demand side solutions – to alleviate the congestion issue; and (iv) develops a regulated transmission solution, for which load would bear cost responsibility, only if there is no market response.

[3] It should be noted that PJM's economic expansion planning process was developed following a lengthy and inclusive stakeholder process, in which all segments of the industry actively participated.

Neither the AEP nor the Allegheny project referenced and effectively championed in PJM's comments have followed this RTEP process. There has been no project-specific "unhedgeable" congestion analysis undertaken. In fact, in PJM's comments herein, PJM notes on the one hand that "[t]his level of congestion underscores the extent to which demand for transmission capability on [the Allegheny Mountain] path exceeds the currently available capacity," yet explains that a "substantial portion of this congestion was hedged through use of financial transmission rights." PJM Comments, at 16 and fn.19. Thus, it is not clear what "problem" the AEP and Allegheny projects are intending to address.[4] By extension, there has been no detailed cost-benefit analysis comparing the "benefits" of the AEP and/or Allegheny transmission projects with the "costs" of the congestion the projects are intended to relieve. Moreover, PJM clearly has ignored the timing inherent in the RTEP process by simply skipping past the one-year market window and moving right to a regulated transmission owner-proposed transmission "solution."

Since neither the AEP nor the Allegheny projects appear to be "merchant" projects, in that they are proposed to be paid for by load through transmission rates whether load wishes to use the project or not, the projects must satisfy the specific criteria established by the RTEP process to "support competition." Under this process, PJM considers reasonable alternatives to a problem that needs to be fixed and seeks out the most <u>cost-effective</u> solution. In the instant circumstances, the "problem" is unclear, and PJM appears to be pre-ordaining a solution (in the guise of NIETC designation) by ignoring market-based solutions and presumably failing to consider alternative regulated transmission solutions. Further, contrary to the RTEP process, PJM has failed to conduct a rigorous cost-benefit analysis to ensure that the projects' benefits significantly exceed its costs so as to justify the ultimate price of the projects to the consumer.

[4] PJM has not claimed that the projects are "reliability" projects intended to address violations of reliability criteria.

Most critical is the fact that the RTEP cost-benefit analysis would seek to ascertain the total cost of these proposed projects, which includes the cost of lower voltage upgrades necessitated by the projects that could considerably inflate the projects' costs.

It is critical, therefore, that the DOE not lose sight of the fact that PJM has its own FERC-approved Tariff process for evaluating economic rate-based transmission projects, and that PJM has to date ignored the process in evaluating the AEP and Allegheny projects. The PSEG Companies are concerned that PJM will use the DOE proposed criteria as a way of unilaterally amending or side-stepping the RTEP process. The DOE should not sanction this result.

Second, the FERC is currently evaluating both the AEP and the Allegheny proposed transmission projects in ongoing docketed proceedings. On January 31, 2006, AEP filed with the FERC (Docket No. EL06-50-000) a request for a declaratory order approving proposed rate incentives for its new 765 kV transmission line project, which would be built from west to east across PJM. Numerous parties intervened in this proceeding, and approximately twenty (20) protests or comments were submitted regarding AEP's filing, including one filed by the PSEG Companies. The FERC has not yet acted on either the filing or any of the protests. Similarly, on February 28, 2006, Allegheny also filed with the FERC (Docket No. EL06-54-000) a request for incentive rate treatment with respect to its proposed transmission line project. Interventions and protests are due to be filed with the FERC by March 29, 2006, and it is anticipated that the Allegheny filing will generate the same level of concern and comment as that engendered by the AEP filing.

The PSEG Companies are concerned that PJM's comments will serve to bypass or undercut a full FERC review of the need for, and efficacy of, both the AEP and Allegheny projects, a review which must be undertaken by the FERC to ensure the projects' satisfaction of

Federal Power Act requirements. As noted, the FERC has already commenced such a review, and many parties have expressed (in the case of AEP) or will express (in the case of Allegheny) significant concerns with respect to the projects. PJM now appears to be using a different forum – the DOE NOI proceeding – to push the merits of these projects. The PSEG Companies caution against using the instant proceeding, which is intended merely to <u>develop the criteria</u> that should be used in designating transmission corridors in accordance with the directives of the EPAct, to pre-judge these projects and effectively hamstring or bias FERC review of the same.

<u>Finally</u>, PJM has not presented a "compelling" need for early NIETC designation of the Allegheny Mountain and Delaware Valley corridors, and by extension for favorable consideration of the AEP and Allegheny projects which will traverse one or both of these paths. PJM's Comments in fact present a skewed and somewhat inaccurate picture of the current need for transmission expansion within PJM. PJM notes that, through the RTEP process, it has gathered "extensive data and analysis" regarding congestion and the markets, PJM Comments at 40. In this regard, PJM makes fairly generalized assertions regarding load growth, "lagging generation additions," and a "spike" in generation retirements, and posits that it is "unlikely that the incremental transmission upgrades currently planned will accommodate all of the necessary imports." PJM Comments, at 17-18, 29. Yet, PJM's hypotheses focus upon only one side of the equation – generation retirements and load growth, while presenting very little actual evidence regarding "lagging generation additions." In fact, PJM itself notes that a "substantial number of projects have been proposed for New Jersey in the most recent PJM interconnection queues," but then discounts this fact by claiming that projects "at this earliest state of development typically suffer the highest rates of attrition …." PJM Comments, at 17 fn 21. Moreover, PJM offers no

data regarding the location of future generation additions, a fact that is critical in evaluating the need for future transmission upgrades.

In addition, PJM ignores and/or mischaracterizes several crucial facts in making its case. For example, PJM fails to mention the fact that it has a 15% reserve margin in place within PJM, thereby requiring load serving entities to reserve generation capacity to satisfy this margin requirement, and that this reserve margin has consistently been met. PJM also does not mention its own Reliability Pricing Model ("RPM") proposal, which has been filed at the FERC for approval in Docket Nos. EL05-1410-000 and EL05-148-000 and seeks to establish a market design that would recognize the locational value of generation capacity, thereby facilitating both the construction of new generation and the retention of existing generation in load pockets.

Finally, with respect to generation retirements, PJM claims in its comments that the "generation owners responsible for [recent] retirements in New Jersey generally have claimed that the retirements are due to the current excess of generation in [western] PJM … and the inability of these particular units to compete economically." PJM Comments, at 18-19. Yet, PJM fails to cite to any support for this statement. Moreover, PJM is simply wrong in making this assertion. PSEG Power's subsidiary, PSEG Fossil LLC ("PSEG Fossil"), is one of the generation owners that contemplated retirement of certain of its units in PJM. PSEG Fossil took such action not because of cheaper "excess" generation in western PJM[5] but because PJM's current market design does not recognize the locational value of units such as Fossil's units that are needed for reliability.[6] Having in place a properly designed RPM mechanism, which is

[5] If in fact there is so much excess generation capacity in western PJM, one would have to assume that adequate transmission capacity exists to move the generation to the east.

[6] The PSEG Companies explained in their comments during a recent FERC technical conference regarding PJM's RPM proposal that "if the current capacity construct had recognized the locational value of capacity resources, it is unlikely the PSEG Power would have needed to seek Reliability Must Run payments in order to continue operating 836 MW of capacity in the PSE&G Zone that PJM determined was required for reliability purposes." Comments of

currently pending at the FERC, would address this concern and should mitigate the threat of generation retirements in eastern PJM.

The picture that PJM paints in its comments leads the reader to the inescapable conclusion that regulated transmission is the only answer in PJM. Yet, PJM has failed to furnish sufficient evidence to support this claim and has in fact presented an apparently biased and incomplete view of the facts. PJM has not explained why it apparently seeks to close the one-year RTEP window for market solutions rather than attempt to figure out if the approach can be revised so that market solutions – where project sponsors bear the financial risk – are still the first option for constructing economic, rather than reliability, transmission projects. In short, PJM has failed to demonstrate why the early NIETC designation of these particular projects is both "necessary and appropriate" in accordance with the NOI.

The PSEG Companies recognize Congress' and FERC's desire to see transmission infrastructure improvements sited and built. Yet, a thorough review of alternative projects – including generation and demand-side response – still must be part of the analysis. As the New Jersey Board of Public Utilities noted in its comments in this proceeding, the DOE should perform an integrated resource planning-type analysis, which would examine both supply-side and demand-side measures as more cost-effective alternatives to the construction of new transmission lines.[7] Further, an appropriate cost-benefit analysis of proposed transmission projects must be conducted when the costs associated with these projects, such as the AEP and Allegheny projects, are to become part of regulated rate base. Such an analysis would evaluate whether large-scale, costly projects like AEP and Allegheny are truly needed, or whether smaller, targeted transmission upgrades are all that is required.

Gary R. Sorenson, Managing Director, PSEG Power LLC On Behalf of the PSEG Companies, Docket Nos. EL05-1410-000 and EL05-148-000, February 3, 2006 Technical Conference.

[7] "Comments of the New Jersey Board of Public Utilities," March 9, 2006, at 9-10.

AEP and Allegheny Comments

Both AEP and Allegheny also submitted comments in this proceeding on March 6, 2006. The companies' comments are similar to those submitted by PJM, in that AEP and Allegheny both seek early designation of particular NIETCs; specifically, AEP seeks expedited designation of the AEP I-765 corridor, and Allegheny seeks early designation of the corridor "necessary for the construction of the Trans-Allegheny Interstate Line Project." Allegheny Comments, at 3; AEP Comments, at 12. By seeking such designations, AEP and Allegheny are obviously attempting to push their own proposed high-voltage transmission lines for favorable consideration by the DOE.

For all of the reasons stated above, the PSEG Companies submit that DOE consideration of these two specific projects is premature, as both projects are currently subject to ongoing PJM economic and reliability transmission planning processes and are the subject of pending FERC proceedings. While AEP claims in its comments that the "reliability need and congestion relief [associated with its project] is abundantly obvious," the PSEG Companies disagree with this conclusion and so explained in a protest filed with the FERC on March 1, 2006 in FERC Docket No. EL06-50-000. As noted above, many other parties have protested AEP's FERC filing as well. Allegheny has also filed with the FERC a request for incentive rate treatment, and interventions and protests are due in that proceeding (Docket No. EL06-54-000) next week. The DOE should not bypass these pending FERC proceedings, where the need for both AEP's and Allegheny's projects will be considered. The purpose of the instant NOI proceeding is to assist the DOE in deciding what types of criteria should be used as it considers designation of transmission corridors, not designation/de facto approval of specific transmission projects. Both AEP and Allegheny are attempting to "jump the gun" by using this DOE proceeding to gain leverage at the FERC. The DOE should not be drawn into this approach, particularly where, as here, neither of these two projects has yet followed PJM's own RTEP process for evaluation of economic transmission projects.

City of New York Comments

In its Comments, the City of New York seeks NIETC designation for a corridor from New Jersey to New York City. The PSEG Companies take no position on the merits of this request for early designation, though the City of New York's comments appear to be devoid of the requisite factual support that would warrant early designation. The PSEG Companies believe that further study by the DOE is needed in this regard.

Moreover, the City of New York mischaracterizes the current status of merchant transmission projects running from New Jersey to New York City. While the City of New York states that "it appears that neither of [two merchant transmission projects from New Jersey to New York City] is likely to move forward on a merchant basis," City of New York Comments, at 5, the Neptune Project has in fact been approved by the FERC as a merchant project,[8] transmission capacity has been subscribed on that line, and reliability upgrade costs are currently being allocated to Neptune by PJM. In fact, the Neptune project has been included in the Base Case Assumptions in the NYISO's recently-approved Reliability Needs Assessment ("RNA"), issued pursuant to the NYISO's FERC-approved Comprehensive Planning Process for Reliability Needs.[9]

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[8] 110 FERC Para. 61,098 (2005); order on rehearing, 111 FERC Para. 61,455 (2005).

[9] See page 2 of the RNA dated December 21, 2005 and published on the NYISO's website at www.nyiso.com/public/webdocs/newsroom/pressreleases /2005/rnafinal12212005.pdf. The NYISO's Comprehensive Planning Process for Reliability Needs is contained in Attachment Y to the NYISO's Open Access Transmission Tariff.

Section 1.1 of Attachment Y provides that the objectives of the process are to "(1) evaluate the reliability needs of the Bulk Power Transmission Facilities ("BPTFs"); (2) identify, through the development of appropriate scenarios, factors and issues that might adversely impact the reliability of the BPTFs; (3) provide a process whereby solutions to identified needs are proposed, evaluated and implemented in a timely manner to ensure the reliability of the system; (4) provide an opportunity for the development of market-based solutions while ensuring the reliability of the BPTFs; and (5) coordinate the NYISO's reliability assessments with Neighboring Control Areas." It should

In addition, an Interconnection Service Agreement and Construction Service Agreement have recently been submitted to FERC for approval in connection with the East Coast Power merchant transmission project, which will run from Linden, New Jersey to Consolidated Edison's Goethals substation in New York.[10] Thus, like PJM, the City of New York paints an inaccurate picture, one in which merchant solutions are not working and regulated transmission is the only way to solve congestion issues. The PSEG Companies take issue with this characterization.

Finally, the City of New York's Comments state that "NIETC designation for the NJ-NYC corridor would … provide a critical link to the current PJM plans to upgrade the corridor from western Pennsylvania to northern New Jersey, and to AEP's plans to build the Mountaineer transmission project from West Virginia to Deans Station, New Jersey." City of New York Comments, at 5. The City of New York appears to simply assume that AEP's transmission project is the correct and preferred approach to address congestion in eastern PJM and by extension in New York City. As explained above, the PSEG Companies do not agree with this assumption, and caution against the DOE accepting this assumption as well.

IV. CONCLUSION

The PSEG Companies understand Congress' objective to strengthen transmission infrastructure in the United States, and regard this objective as meritorious. Yet, as the DOE itself recognizes in the subject NOI, implementation of this objective is complex and must be

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be noted that, following the issuance of the RNA, the NYISO solicited requests for market-based, utility backstop and third-party regulated solutions to the reliability needs identified in the RNA. Thus, in light of this ongoing process, the City of New York's comments herein, like PJM's comments, are premature. Specifically, the City of New York's efforts to promote early NIETC designation of a New Jersey-New York City corridor are premature and do not satisfy the "necessary and appropriate" threshold articulated by the DOE in its NOI.

[10] The ISA and CSA were filed with the FERC for acceptance on February 16, 2006 in Docket No. ER06-649-000.

considered in a careful, step-by-step manner. In their comments herein, PJM, AEP, Allegheny and The City of New York appear to be using this proceeding to advocate on behalf of particular high-voltage, long-line transmission projects, projects which have not yet satisfied all of the requirements established by existing regional planning processes and which are currently being examined by the FERC. Issues such as need for the project, cost, and viability of alternatives – generation, demand-side and smaller-scale transmission projects – all must be addressed. The PSEG Companies respectfully request that the DOE give full consideration to these issues prior to accepting the commenters' request for early NIETC designations.

Respectfully submitted

Public Service Electric and Gas Company
PSEG Power LLC
PSEG Energy Resources & Trade LLC

By: *Jodi L. Moskowitz*
Jodi L. Moskowitz

Newark, New Jersey
March 23, 2006

6. Seminole Electric Cooperative, Inc., Received Wed 3/8/06 3:14 PM

UNITED STATES OF AMERICA
BEFORE THE DEPARTMENT OF ENERGY
EPACT Comments of
Seminole Electric Cooperative, Inc.
March 6, 2006

Commenting Party: These comments are being submitted by Seminole Electric Cooperative, Inc. ("Seminole") in response to the Department of Energy's ("DOE") Notice of Inquiry issued February 2, 2006 (71 Fed. Reg. 5660). Seminole is a non-profit electric generation and transmission cooperative organized under the Rural Electric Cooperative Law of Florida (Chapter 425, Florida Statutes). Seminole's corporate purpose is to supply wholesale electric power and energy at the lowest feasible cost to its ten member non-profit, rural distribution cooperatives. Seminole's member systems provide retail electric service to over 840,000 consumers in 46 Florida counties. In 2005, member system retail sales were in excess of 15 billion kWh. Seminole strongly supports the DOE's undertaking both because of the need nationally and in Florida for prompt action as regards deteriorating and increasingly inadequate transmission infrastructure.

Problem: a major region of the country – a region important to our national defense and our overall wellbeing, a region with a burgeoning electricity market, and a region served primarily by two vertically integrated utilities – is for all intents and purposes isolated electrically from the rest of the nation.

The affected region is Florida. The problem that plagues much of the nation, *i.e.*, inadequate infrastructure to move power between and among neighboring utilities, is many times more serious in Florida because the entire state is virtually cut off from outside power resources. The total available interface capacity between Florida and its neighbor to the north, Georgia, is a meager *3600 MW (summer)/3700 MW (winter)* for Florida imports, constituting less than *8%* of the peak demand in Florida, virtually all of which is committed to a few large utilities in the state. This situation, which has long been *contra* the public interest, is no longer tolerable in view of changes in the power industry and in the world in which we live.

In brief, there is a classic bottleneck between Florida and the rest of the nation, and the bottleneck impedes economic transfers and creates security vulnerabilities that could have significant adverse consequences to our nation. If ever there was a "national interest electric transmission corridor," it is the corridor between Florida and the power suppliers to the north.

The need for a broad power corridor to the north is underscored by recognition of the huge role that natural gas plays in the generation of power in Florida and of the few means of ingress for natural gas into the State. Until fairly recently, peninsular Florida was served by a single interstate pipeline (Florida Gas Transmission); with the addition in 2002 of Gulfstream Natural Gas System as a second pipeline into the middle of the State (via the Gulf of Mexico), there is now minimal diversity but virtually no redundancy. Florida has no natural gas production and no gas storage facilities. Nor does it have indigenous coal. A terrorist act or a Katrina-like act of nature could leave Florida power and gas consumers without energy for a sustained period of time, to the very great detriment of both that region and the nation.

In brief, there exists a *bottleneck* into a region of significant *national importance* – a region that is growing at a very high rate, with no anticipated surcease. This problem requires prompt attention by the DOE.

Comments on the Criteria: The DOE Notice of Inquire on considerations for transmission congestion study and designation of national interest electric transmission corridors ("NIETC") lists eight criteria on which it seeks comments; these eight criteria are addressed below, both generally and in the context of the situation in Florida.

Criterion No. 1: maintain high reliability. The NOI correctly points out (71 Fed. Reg. at 5662) that "[m]aintaining high electric reliability is essential to any area's economic health and future development." Seminole agrees wholeheartedly, and would simply point out the obvious, *viz*: under this criterion, numerous areas of the country, including several *within* Florida, would qualify for NIETC status. The point, of course, is that in determining NIETC status DOE will have to look at the size of the impacted area (in terms of load and geographic area) and importance to the nation's well-being of the area impacted. The situation in Florida is unique in that regard because the entire state is impacted by the lack of meaningful transmission access to the north.

Criterion No. 2: economic benefits for consumers. The interstate regulation of the electricity market is premised upon benefiting consumers through increased wholesale power trading, trading which is currently impossible in many areas of the nation. In Florida, for example, since there is no regional transmission provider (and hence no meaningful regional transmission planning), and since the major utilities were built in balkanized fashion to serve their native load, trading is minimal. If power customers in Florida had access to power suppliers to the north, then the potential economic benefits to consumers would grow enormously, especially in light of the open access transmission requirements of the Federal Energy Regulatory Commission.

Criterion No. 3: ease electrical supply limitations and diversify resources. These are important considerations that should be considered. As discussed, Florida is the poster child for the perils of electrical isolation and the inability to diversify due to lack of indigenous energy resources and lack of access to the outside world.

Criterion No. 4: energy independence of the United States. This is an important theme of the administration, and one that needs to be emphasized in all energy sectors. Florida's dependence on natural gas is already leading to reliance on imports of LNG from abroad, which imports, while they serve a useful short-term purpose in terms of ameliorating supply (and hence potentially price) problems afflicting the natural gas market, will *increase* our dependence on foreign sources for gas imports (and it is noteworthy that many of the countries exporting LNG have no love lost for the United States and are already talking about an forming an OPEC-like cartel to control supply and prices in the future). Thus, it is important that transmission corridors be built that permit regions of the country like Florida to access power from other areas that are less dependent on natural gas.

Criterion No. 5: further national energy policy. A key element of national energy policy is diversity, both because diversity makes this country less vulnerable to a targeted attack on a single resource and because diversity makes us less susceptible to blackmail by other countries that understand this nation's dependence on foreign energy resources. As noted above, allowing Florida to join the rest of the nation electrically (by designating the Florida-Georgia interface as a NIETC) fosters these goals.

Criterion No. 6: reliability of electricity supplies to critical loads and facilities. Florida has critical loads related to national defense as well as important ports. It is also uniquely vulnerable to attacks from Mother Nature and from those bent on this country's destruction given that it is bounded almost entirely by water. Because of this combination of factors, having access to power from the north is especially vital to our national interest.

Criterion No. 7: not unduly contingent on uncertainties associated with analytic assumptions. There can be no question that there are sufficient areas in this country whose needs are real and pressing without resort to various economic and other assumptions underlying many analyses regarding potential future problems. The DOE should focus on the here and now in putting together its NIETC list, at least at the outset, so that it can address in a meaningful manner the many dire situations confronting this nation's electrical grid. Given the lead time to build significant transmission infrastructure, some reliance on various assumptions is necessary to ensure that you are not protecting against a problem that will take care of itself in time. The situation in Florida, however, is not academic; and the assumptions that the load in Florida will grow, that Florida will continue to rely on energy sources from outside its borders, and that it will remain vulnerable to attacks from nature and from those intending this country no good are not subject to real debate.

Criterion No. 8: alternatives have been addressed. This is clearly an important consideration; building expensive transmission to cure a problem that can be cured by other, perhaps less costly (in real dollars and in terms of impact on the environment) means must be avoided. In Florida, the alternative has been to build more gas-fueled generation, which, of course, has worsened the situation in terms of dependence on a single fuel (which soon will be supplied in significant amounts from abroad) and hence Florida's vulnerability to price fluctuations and external attacks. In short, the alternatives available to Florida only tend to worsen its situation and hence are not alternatives at all in terms of achieving the various goals set forth in the other criteria in the DOE's NOI.

Conclusion: Seminole wholeheartedly supports the DOE's effort to identify NIETCs, as it is of the firm belief that the deterioration of this country's transmission infrastructure is a major national issue that threatens to undermine our economic well-being and our homeland security. Seminole understands that there are many areas of the country that require additional transmission capacity yesterday; however, focusing on the criteria that DOE has identified, which Seminole supports, Seminole believes that no case is more compelling than the need for prompt, significant transmission infrastructure investment to enhance the Florida-Georgia interface so that an area of the country of vital national significance can electrically join the rest of the Union.

Respectfully submitted,

Timothy S. Woodbury

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7. Wisconsin Public Power Inc., Received Fri 6/03/06 1:27 PM

June 2, 2006

Via E-Mail EPACT1221@hq.doe.gov
Office of Electricity Delivery and
Energy Reliability, OE-20
Attention: EPACT 1221 Comments
U.S. Department of Energy
Forrestal Building, Room 6H-050
1000 Independence Avenue, S.W.
Washington, D.C. 20585

RE: **Comments of Wisconsin Public Power Inc. on the Department of Energy's Notice of Inquiry, *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors,* 71 Fed. Reg. 5660 (Feb. 2, 2006)**

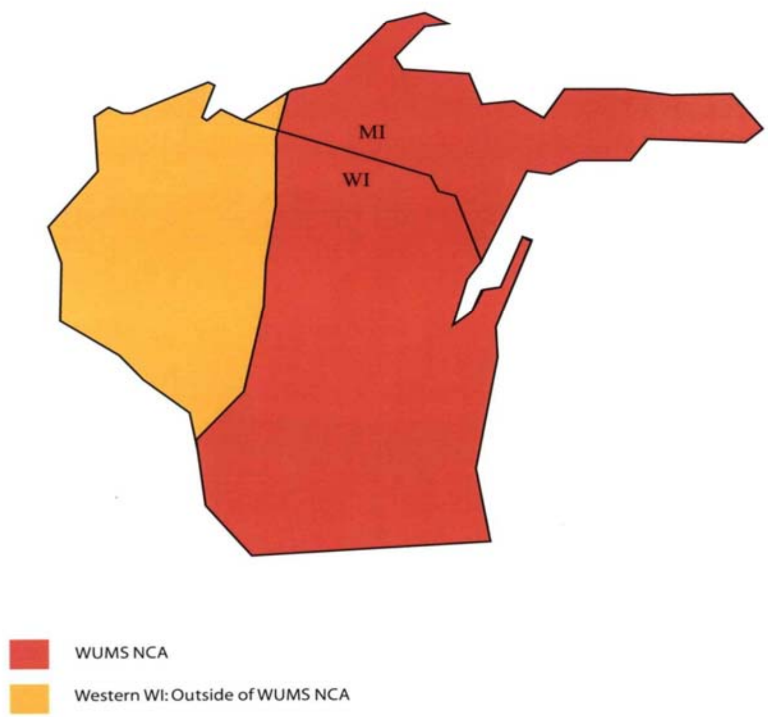
In response to the February 2, 2006, Notice of Inquiry ("NOI") issued by the U.S. Department of Energy ("DOE" or "the Department") on *Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors,* Wisconsin Public Power Inc. ("WPPI") submits its comments regarding DOE's plans for an electric transmission congestion study and the proposed criteria for the designation of National Interest Electric Transmission Corridors ("NIETCs" or "Corridors"). The NOI was issued to implement Section 1221 of the Energy Policy Act of 2005 ("EPAct 2005"), which amends Part II of the Federal Power Act by addition Section 216, "Siting of Interstate Electric Transmission Facilities."

WPPI supports the comments previously submitted by the American Public Power Association ("APPA") on March 6, 2006, as well as those submitted on that date by the Transmission Access Policy Study Group. It submits this separate comment to describe the serious transmission deficiencies in the Wisconsin and Upper Peninsula of Michigan ("WUMS") area, explain the economic harm such deficiencies are causing consumers within WUMS, and seek designation of appropriate transmission corridors by DOE that would remedy the lack of transmission import capacity into WUMS.

The Wisconsin – Upper Michigan System

The WUMS transmission area is that portion of the electric grid located in eastern Wisconsin, generally east of the Wisconsin River Valley and in portions of the Upper Peninsula of Michigan. The area consists of the balancing authorities in Wisconsin (the former control areas) of Wisconsin Electric Power Company (WEPCO), Alliant – East (WPL), Wisconsin Public Service Corporation (WPS), and Madison Gas and Electric Company (MGE); and in the Upper Peninsula of Michigan, the balancing authorities of WEPCO, WPS and Upper Peninsula Power

Company. The transmission owner in the WUMS area is the American Transmission Company LLC ("ATCLLC"). See the following map.



WUMS is bordered to the north by Lake Superior and to the east by Lake Michigan. The region's ties to the rest of the Eastern Interconnection are through what are known as the southern interface (the Wisconsin-Illinois border) and the western interface (across western Wisconsin to Minnesota and Iowa). (Minnesota and Iowa are part of the Mid-Continent Area Power Pool, or MAPP, and the interface is sometimes referred to as the MAPP – WUMS interface.)

WUMS has only four 345 kV voltage connections to the remainder of the Eastern Interconnection. There presently is only one 345 kV line across the western interface to Wisconsin. ATCLLC is currently in the process of constructing a new 345 kV line from Duluth, Minnesota to central Wisconsin. This line is known as the Arrowhead-Weston. It will provide a second 345 kV connection between the MAPP area west of Wisconsin and WUMS when it is completed in 2008. There are three 345 kV lines that cross the southern interface from Illinois into WUMS.

Wisconsin's existing four high-voltage connections to neighboring states are far fewer than those in most Midwest states. Today, Minnesota, Iowa, Illinois, Nebraska, South Dakota, and North Dakota each possess at least fifteen 200 kV or higher voltage transmission links to neighboring states.

Transmission Congestion in WUMS

Because there are few high-voltage transmission lines linking WUMS to surrounding areas, those lines tend to carry higher loads than other lines and are more frequently constrained or congested. The Department of Energy's May, 2002 National Transmission Grid Study ranked the MAPP-WUMS constraint fourth highest, among the twenty most congested paths in the Eastern Interconnection, in terms of hours of congestion. The Study noted that the MAPP-WUMS constraint is congested during 73% of the hours in the year.

The MAPP-WUMS constraint is singled out for mention in the January 2004 State of the Markets for January 2002 through June 2003 Report by FERC Staff from the Office of Market Oversight and Investigations.[1] In describing the generally high level of reserves in Midwest markets, the report noted (at 50): "However, there are congested areas within the Midwest, most notably, the Wisconsin-Upper Michigan subregion (WUMS). Congestion in the WUMS area is in part due to transmission configuration changes and a weak transmission interface."

Market Power

The WUMS area is characterized by very high generation concentration. Most of the generation located in WUMS is owned or controlled by the three largest utilities,[2] with nearly 50% of the generation owned or controlled by WEPCO, which lacked authority to sell at market-based rates within WUMS prior to the advent of the Midwest ISO.[3] The Midwest ISO's independent

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[1] Available at http://www.ferc.gov/legal/maj-ord-reg/land-docs/som-2003.pdf (last viewed June 1, 2006).

[2] For example, in *Wisconsin Elec. Power Co., et al.*, 79 F.E.R.C. ¶ 61,158, at 61,693-96 (1997), the Commission found that the market in eastern Wisconsin was highly concentrated. In *IES Utils., Inc.*, 81 F.E.R.C. ¶ 61,187, at 61,822 (1997), the Commission acknowledged the admission by applicants' witness that the WUMS market was highly concentrated (with pre-merger HHIs ranging from 1974 to 2658). *See* Exhibit __ (RWF-23) (REVISED) at page 1 of 7, in Docket Nos. EC96-13-000 and ER96-1236-000, Feb. 27, 1997 (FERC Accession No. 19970303-0259).

The Public Service Commission of Wisconsin has described WUMS as "an electric 'island system,' a limited market in which a large electric generating firm can obtain leverage over the prices paid for electricity." *See* Approval of Affiliated Interest Transactions Between W.E. Power, LLC, Wisconsin Electric Power Co., and Wisconsin Energy Corp., PSCW Docket No. 05-AE-109, Final Decision, at 23-24 (Dec. 20, 2002).

[3] *Wisconsin Elec. Power Co.*, 82 F.E.R.C. ¶ 61,067 (1998).

market monitor ("IMM"), in presenting his 2003 State of the Market Report, told FERC that the HHI in WUMS was 2,656, which is highly concentrated.[4]

Midwest Day 2 Energy Markets

On April 1, 2005, the Midwest ISO Day 2 energy markets began operations. The Midwest ISO's Independent Market Monitor (IMM) has developed a set of rules, approved by FERC, that are intended to mitigate the exercise of market power in the Midwest ISO Day 2 market. Among other restrictions, the rules, generally applicable during times when a transmission constraint is binding, prohibit withholding available generation from the market and place a cap on the prices at which market participants may offer their generation into the market. The market mitigation rules vary in their severity, depending upon whether they are applied in what the IMM construes as a Broad Constrained Area (BCA) or a Narrow Constrained Area (NCA). Under the Midwest ISO energy markets tariff, a Narrow Constrained Area is a market that is effectively separate from the larger market. The Midwest ISO Transmission and Energy Market Tariff (TEMP) § 63.4.1(b) defines an NCA as "an electrical area identified by the IMM that is defined by one or more Binding Transmission Constraints that are expected to be binding for at least five hundred (500) hours during a given twelve (12) month period and within which one (1) or more suppliers are pivotal." The IMM has found that WUMS and North WUMS (i.e., the Michigan portion of WUMS) are the only Narrow Constrained Areas within the Midwest ISO market.

Market Prices

As a result of WUMS' transmission situation, WUMS has, by far, the highest energy prices in the Midwest ISO's footprint. The data for the first seven (7) months of the average market energy price (average price around the clock)[5] were:

Eastern Wisconsin Energy Cost Premium

MISO Area	Average Market Price $/MWh	Market Premium $/MWh	Market Premium %
Eastern WI	63.92		
Rest of MISO	52.15	11.77	23%
Illinois Hub	46.69	17.23	37%
Minn. Hub	46.39	17.53	38%
Cinergy Hub	50.37	13.55	27%
Michigan Hub	53.57	10.35	19%

(April – October, 2005)

[4] Independent Market Monitor, Midwest ISO, Highlights of the Midwest ISO 2003 State of the Market Report, at 7, *available at* http://www.ferc.gov/EventCalendar/Files/20040505115830-A-3-MISO.pps (last viewed June 1, 2006).
[5] This data is taken from actual LMPs as made publicly available by MISO. Eastern Wisconsin data is compiled from load-weighted nodal data.

The data shows that consumers within WUMS are paying a very high premium for energy purchased from the Midwest ISO's market. This premium is almost exclusively caused by lack of transmission capacity.

The high prices prevailed even with a) the market power mitigation provisions of the Midwest ISO's tariff and b) generator bid for the first two months of market operation limit to cost-based bidding across this Midwest ISO footprint.

An NIETC Designation Could Prove Important for Resolving these Constraints

Because of WUMS location, efforts to resolve the severe constraints that plague WUMS will often be multi-state in character, *e.g.*, involving upgrades in Illinois and/or Minnesota, or beyond. While a major new line – the Duluth-Weston line – is currently under construction (with completion anticipated in the 2008-09 time frame), it will not solve WUMS' transmission woes, especially given load growth and other limiting factors. While a necessary and important step in addressing WUMS constraints, this line is not sufficient to solve the problem. Thus, NIETC designation could be very important in supporting the future upgrades required to bring relief to WUMS consumers.

Conclusion

The above facts establish beyond question that due to limited transmission import capability WUMS is a highly congested load pocket and as a consequence consumers in WUMS pay a premium for electric power. WUMS plainly constitutes a "geographic area experiencing electric energy transmission capacity constraints or congestion that adversely affects consumers." FPA Section 216(a)(2) (to be codified at 16 U.S.C. § 824p). Thus, the corridors into WUMS should be designated by DOE to remedy the economic risk and harm.

Respectfully submitted,

/s/ Michael Stuart

Michael Stuart
Senior Vice President
Legal & Regulatory Affairs

8. Revised Comment - City of Fayetteville, North Carolina, Public Works Commission [submission included here contains an addendum to original submission received Mon 3/6/2006 3:58 PM]

UNITED STATES OF AMERICA
BEFORE THE
UNITED STATES DEPARTMENT OF ENERGY

Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors	Notice Of Inquiry

COMMENTS OF THE PUBLIC WORKS COMMISSION OF THE CITY OF FAYETTEVILLE, NORTH CAROLINA

I. INTRODUCTION AND GENERAL PROBLEM

The Public Works Commission of the City of Fayetteville, North Carolina (hereafter "Fayetteville" or "PWC") appreciates this opportunity to respond to the Department of Energy's Notice of Inquiry, "Considerations for Transmission Congestion Study and Designation of National Interest Electric Transmission Corridors," which was published in the Federal Register on February 2, 2006. 71 Fed. Reg. 5660. PWC is a member of ElectriCities of North Carolina, Inc., and thus a member of the Transmission Access Policy Study Group ("TAPS"), which is filing generic overall comments today in this proceeding. We agree with those TAPS comments, but wish to add specific factual material to this record, as the TAPS comments have suggested will be done by TAPS members. The NOI as issued spells out:

> ***In that regard, if interested parties believe that there are geographic areas or transmission corridors for which there is a particularly acute need for early designation as NIETC, the Department invites interested parties to identify those areas in their comments on this NOI.*** If such areas are identified, the Department will consider whether it should complete its congestion study for that area in advance of the larger national study discussed elsewhere in this NOI, and proceed to receive comment and designate that area as an NIETC on an expedited basis. If interested parties wish to identify areas for early

> designation, they should supply with their comments all available data and information supporting a determination that severe needs exist. Parties should identify the area that they believe merits designation as an NIETC, and explain why early designation is necessary and appropriate. The Department will only consider for early designation as NIETCs those corridors for which a particularly compelling case is made that early designation is both necessary and appropriate, and for which data and information are submitted strongly supporting such a designation.

Fayetteville owns and operates a municipal electric system that provides retail electric service to residential, commercial, and industrial customers in the City of Fayetteville, North Carolina and surrounding areas. In connection with this service, Fayetteville owns and operates generation, transmission, and distribution facilities used to provide electric service to the public. Fayetteville is interconnected with Carolina Power & Light Company, also known as Progress Energy Carolinas, Inc.[1]

On August 16, 1999, Fayetteville issued a request for proposals for firm power supply to meet its demand and energy requirements beginning July 1, 2003. In response to that RFP, Fayetteville received a number of proposals, and found that most sellers had proposed to utilize one version or another of the form contract prepared by a committee of representatives of Edison Electric Institute and the National Energy Marketers Association member companies (referred to hereinafter as the "EEI Agreement"). As a result of that RFP process Progress Energy was selected as the successful bidder and three interrelated agreements were – after extended negotiations – entered into and became effective on July 1, 2003: a Master Power Purchase and Sale Agreement, a

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[1] We will refer to CP&L (or Progress Energy Carolinas, Inc.) as "Progress Energy" or simply "Progress" herein. Although there is also a Progress subsidiary in Florida, this filing addresses only issues applicable to Progress Energy Carolinas.

Marketing Agency Agreement, and a Scheduling and Services Agreement. Those agreements continue in effect through June 30, 2012. Under those agreements, Fayetteville purchases firm base and intermediate power supply from Progress, and supplies the balance of its requirements from its own peaking resources or from short-term market purchases when available. Fayetteville also became a network transmission customer of Progress Energy under its OATT, although PWC has approximately 200 MW of internal generation serving part of its load, which is approaching 500 MW on peak.

Under those agreements, PWC is entitled to purchase power and energy above the amounts purchased from Progress from other competitive entities if it is cheaper for it to do so. But Fayetteville has found that transmission constraints on the Progress system severely limit its ability to actually purchase energy from short term markets outside the Progress control area to displace more expensive energy from its own generation facilities. The last time Fayetteville was able to make any off-system purchases from outside the Progress control area was more than a year ago, in December, 2004. Fayetteville's inability to purchase in the short-term market is largely due to physical limitations on the Progress system.[2]

Even more serious, however, than the inability to purchase power on the short-term market, is the lack of transmission capacity for power supply alternatives when the current contract expires in 2012. Progress undertook a Scoping Study of interface capacity which found that starting in 2010 there will be <u>no</u> long-term firm transmission capacity available for importing power into the Progress control area in

North Carolina. Furthermore, the most likely transmission upgrades to alleviate this limitation could not be placed into service until 2016 or after. Because Fayetteville is a network transmission customer, Progress is responsible for planning its transmission system to provide for the needs of Fayetteville as well as for Progress's own needs. When Fayetteville's current power supply contract with Progress expires in 2012, however, if something is not done, it will be foreclosed from power supply options outside the Progress control area, and Progress is the only entity with sufficient base and intermediate power supply inside that area potentially available to meet Fayetteville's needs.[3] Consequently, Fayetteville will be limited to the current transmission supplier as its only power supplier option, unless new generating resources are constructed. Fayetteville is willing to participate in any way needed to promote transmission access and will consider joint ownership of a load ratio share of the transmission grid, if that will expedite transmission improvements. However, the failure of the transmission provider to solve this basic problem is a failure to meet the obligation to build for the needs of network customers (as well as for Progress's own customers). Clearly, something further needs to be done to assure transmission adequacy to support a competitive market.

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[2] There may also be artificial constraints associated with the methods of calculating ATC and TRM.

[3] There is some potential that peaking capacity will be built by North Carolina Electric Membership Corporation, but no indication known to Fayetteville of base or intermediate power capacity being built.

II. DETAILED DESCRIPTION OF WHY THE IMPORT LIMITATIONS OF PROGRESS SHOULD QUALIFY FOR EARLY NIETC DESIGNATION

A. Standards

As noted in the TAPS comments, TAPS members generally agree with the criteria proposed to be used in identifying transmission corridors of national interest. With respect, we believe that proposed criteria 1, 2, 3, 5, 6, 7 and 8 are met.

B. Short-Term limitations

As described above, Fayetteville currently receives its base and intermediate power requirements (approximately 300 MW) from Progress under an agreement which extends until June 30, 2012. The balance of Fayetteville's requirements is supplied from its own peaking generation, which is located in Fayetteville (approximately 200 MW), or from short-term market purchases when transmission is available. Fayetteville receives network transmission service from Progress under its OATT. The term of the transmission service coincides with the power supply commitment.

Because of current transmission constraints, Fayetteville is unable to purchase energy from the short-term resources outside the Progress control area to displace more expensive generation from its own resources (the Butler-Warner generating plant). Every morning at about 0720 a conference call takes place between the Progress traders and Fayetteville Control Room personnel. The purpose of this call is to develop plans for covering the projected Fayetteville load for the following day. The plans that were made on the preceding day for covering the Fayetteville load for the current day are also revisited at that time to determine if additional resources are going to be required or if the availability of any resources that were expected to be used has changed overnight. During that conference call, Progress advises Fayetteville whether there is any import capability to make market purchases of energy at a lower price than the cost of Butler-Warner generation. On every day during the summer months of 2005 for the hours that Fayetteville's load was above the floor, the report from Progress has been that there is no import transmission capacity available. On some of those days, there may not have been energy available at a lower cost, but there would have been no transmission availability in any event. The last time PWC was able to make any off-system purchase from outside the Progress control area was in December 2004. Thus it seems clear that even now there is no ability to obtain electricity at a competitive price in the wholesale market (Draft Criterion 5, since it is stated national policy to have a competitive wholesale market; see also Draft Criterion 2 and 3).

C. The Prospect for Long-Term Relief Is Bleak

As noted above, studies conducted by Progress in connection with efforts by North Carolina Electric Membership Corporation to import long-term firm power supply into the Progress control area showed, among other things, that starting in 2010, there will be <u>no</u> long-term firm transmission capacity available for importing power into the Progress control area. While the limiting factor (a phase-angle difference at a point of interconnection with Duke Power) could be corrected through construction of a new high-voltage transmission line to the Progress interties with the Duke system, such a line could not be placed into service until 2016 or after.

Attached as Exhibit A is an Import Scoping Study prepared by Progress on April 23, 2004, evaluating constraints at interties with other utilities. It shows that interties are constrained and concludes that, in order to provide 250 MW of additional import capability, the most cost effective alternative would be to upgrade the

Cumberland-Richmond-Newport tie line with Duke Power, which was estimated to cost $350 million and require at least ten years to complete. Obviously, this schedule would mean that Fayetteville will be deprived of any other alternative for supply of base and intermediate power (what is needed after the use of its own on-system peaking resources) when the current power supply contract expires in 2012, and that Progress has not expanded its transmission system for the known needs of network transmission customers like Fayetteville, as it is obligated to do.

Fayetteville believes that there should be a full evaluation of shorter term and less expensive options for interim relief on the tie line with Duke Power, such as modifications in switching facilities to allow the tie line to be loaded more fully. The additional capacity would be beneficial in the near term to provide much needed intertie capability until the proposed longer term project can be undertaken.

Among the alternatives being considered by Fayetteville are construction of its own transmission facilities to interconnect with suppliers outside the Progress control area and the construction of additional Fayetteville generation facilities to supply its base and intermediate power requirements. Neither of these options is the most efficient alternative, however.

Construction of transmission facilities likely will extend more than fifty miles and cross the path of Progress Energy's own 500 kV transmission lines. Construction of 300 to 400 MW of base load generation independently would not be the most efficient alternative either. Further, Fayetteville is not likely to be able to obtain environmental approvals to construct additional gas or coal-fired generation in its service territory.

Fayetteville will participate in any reasonable way needed to promote transmission access to more economical generation alternatives. Fayetteville also is willing to consider joint ownership of a load ratio share of the transmission grid if that will expedite funding of transmission improvements.

Fayetteville has participated, through ElectriCities of North Carolina, Inc., in a series of stakeholder meetings sponsored by the North Carolina Utilities Commission ("NCUC"), designed by the NCUC to "become better informed about the status of the electric transmission facilities in North Carolina and the potential transmission-related issues that might arise in the future" and to "identify any specific electric transmission issues that have the potential to impact the ability of transmission dependent load-serving entities to provide reliable and adequate service to their retail customers." The NCUC-sponsored process led to the recently executed "North Carolina Load Serving Entities' Transmission Planning Participation Agreement" among ElectriCities, NCEMC, Progress and Duke Power. While we are all hopeful that the process there established will lead to an adequate transmission network plan to solve the problems in the Progress region, over ten years will be needed, by Progress's own assessment. This time frame as estimated by Progress is not adequate to address Fayetteville's needs. We believe that this situation warrants designation of a transmission corridor in North Carolina by DoE to facilitate the necessary transmission system upgrades.

Since it seems clear that NIETC listing will help speed up planning and construction, and since it also appears clear that on a long-term basis the existing problem clearly meets Draft Criteria 1 (reliability), 2 (economic benefit for consumers), 3 (action needed to ease supply limitations in corridor), 5 (action would further the national energy policy of wholesale competition), 6 (action is needed to enhance the reliability of electric supply to critical loads and infrastructure), and 7 (alternatives have been thoroughly studied), Fayetteville respectfully requests that the constraints in the Progress Energy Carolinas grid which limit the ability of entities like Fayetteville to import power be included as a part of the NIETC listings.

Respectfully submitted,

/s/ James N. Horwood

Robert C. McDiarmid
James N. Horwood

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March 6, 2006

EXHIBIT A

Progress Energy Carolinas, Inc.
Eastern Area Transmission System
Import Scoping Study

Progress Energy

April 23, 2004
Transmission Department
Progress Energy Carolinas, Inc.

Purpose

The purpose of this study is to address an issue that has been found to limit future import capability of the Progress Energy Carolina's (PEC) eastern control area. This study was performed following results of OATT studies performed in association with a request for transmission service, specifically OASIS request # 216803. This request was for a 250 MW import into PEC sourcing from Dominion Virginia Power and sinking in the PEC control area beginning January 1, 2005. The Customer requested rollover with this request. Results of the study concluded that PEC was unable to confirm the import beyond 2009 due to an emerging issue with post-contingency phase angle difference on its Duke 500 kV interface in the south-western part of its system.

PEC's 500 kV EHV Transmission System

PEC's bulk transmission system includes 300 miles of 500 kV EHV transmission that is the backbone of the PEC system. PEC has 5-500kV substations. PEC interconnects with Duke Energy in the south-western part of its system at the Richmond 500 kV Substation and with Dominion Virginia Power in the northern part of its system at the Wake 500 kV Substation. The Cumberland 500 kV Substation is an intermediate station between Richmond and Wake. At these 500kV stations 500/230kV transformers serve PEC's underlying 230 kV systems. Also included is a 500 kV line extending from Wake 500 kV Substation to PEC's Mayo 500kV Substation and terminating at the Person 500 kV Substation. In addition to providing load serving capability for PEC control area load, the 500 kV system also provides through-flow for inter- and intra- regional transfers for flows in support of power movement in SERC and flows for transfers into or out of SERC with surrounding control areas in ECAR, MAAC, MAIN, and PJM.

Phase Angle Criteria

PEC currently uses phase angle as a criteria to manage the design and operation of its transmission system. For circuits that normally carry significant power flows, the phase angle difference of the circuit when opened provides a means of monitoring the severity of system impacts when closing the circuit. Closing a circuit with a large phase angle difference produces a step-change in power flow on area generation that can have adverse consequences to reliability. This step-change is influenced by system impedances and power-flows. Power-flow is a function of system configuration, generation pattern, and active internal and external scheduled transactions. Adverse consequences of closing breakers with large phase angle differences may include,

- Damage to transmission infrastructure due to potentially catastrophic switching transients that exceed breaker capabilities.
- Increased potential for area transmission outages.
- Damage to the rotating and stationary components of area generating units due to transient and oscillating mechanical forces.
- Increased potential of area generating unit trips.

Published industry standards, specifically, IEEE Standard C37.102-1995, provide guidance on this issue. Based on historical experience and lessons learned from past events, PEC utilizes a 30° phase angle difference as its limit. Sync-check relay protection incorporates this limit by design to not allow closing of a breaker if sync-check measures more than a set 30° phase angle difference. This relay safeguard is to prevent the introduction of a disturbance on the PEC transmission system that could affect generation stability in the area and possibly result in equipment damage and an adverse impact on grid reliability. PEC currently has developed a special operating procedure that consists of a sequence of switching operations when a 30° difference is encountered at certain points of its 500 kV system.

Emerging Phase Angle Issue

Results of studies for OASIS #216803 concluded that PEC was able to confirm portions of the import request through 2009 but not beyond due to post-contingency phase angle differences. Studies show that if the Richmond – Newport 500kV line experienced an outage during periods of high control area imports, the additional line loadings associated with request #216803 would result in a phase angle differential greater than 30° at the Richmond 500 kV terminal which will prevent the circuit breaker from reclosing. Quickly returning the circuit back to normal is necessary under NERC requirements[1]. Not being able to reclose this 500 kV line would have adverse impact to transmission grid reliability. For use when this condition is present, PEC has developed an Operating Procedure which identifies a sequence of switching instructions that will allow this 500 kV transmission line to be returned to its normal configuration when the phase angle difference is up to 35° (i.e. this operating procedure reduces the phase angle difference approximately 5°). At the time of studies for OASIS request #216803, additional imports rendered this Operating Procedure ineffective beyond 2009.

Methodology

The goal of this initial study is to scope a potential transmission solution that would support PEC's current 2010 import obligations plus an additional import of 1000 MW. It was necessary to specify a source for the additional 1000 MW. Since the phase angle issue is associated with PEC's 500 kV tie with Duke, Duke was chosen as the source of the additional import. The year chosen for the study was 2010 since the results of studies for OASIS #216803 indicated limitations after 2009. The size, source and schedule for this hypothetical import were assumed for the purpose of this scoping study only.

An import power flow case was developed. The interchange consisted of PEC's control area import obligations for 2010 summer. Interchange included import reservations of load serving entities, required import from SEPA for control area preference customers, imports for PEC native load, and transmission margin reserved for the benefit of all control area load. A listing of these reservations is shown graphically in Figure 1. Base imports total 3603 MW and 4603 MW with the additional 1000 MW import.

[1] Compliance with NERC Operating Policy 2, following a contingency or other event that results in an OPERATING SECURITY LIMIT violation, the CONTROL AREA shall return its transmission system to within OPERATING SECURITY LIMITS soon as possible, but no longer than 30 minutes.

2010 Summer
PEC Control Area Obligations & Test Import

Figure 1

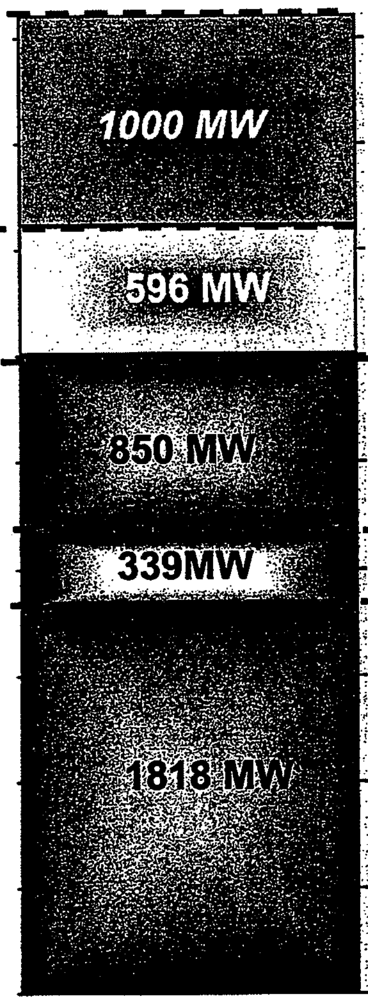
4603 MW

Added Hypothetical Import — *1000 MW Via Duke*

3603 MW

LSEs (NCEMC, Tri-Towns) — AEP/NCEMC 205MW, AEP/NCEMC 100 MW, SCEG/NCEMC 100 MW, SCEG/NCEMC 150 MW, SoCo/NCEMC 25 MW, VP/Tri-Towns 16 MW

Base Imports
- Broad River — Duke/BroadRiver 850 MW
- Other base — AEP Rockport 250 MW, VP SEPA 95MW, PEC/ West-to-East 150MW, PEF 50 MW, SCPSA/QF 9MW, VP/NCEMPA -175 MW, VP/Littleton -8 MW, Duke/Seneca -32MW[1].



TRM -Transmission transfer capability reserved that provides a reasonable level of assurance that the interconnected network will be secure. PEC considers variation in dispatch, loop flow, and Operating Reserves in developing TRM quantities.

Interface	MW
AEP	97
Duke	505
SCE&G	191
SCPSA	194
VP	831

[1]*Negative entries are exports permitted to net during import studies.*

Progress Energy
Progress Energy Carolinas

April 23, 2004

Solutions Tested

Power normally flows into the PEC system from Duke on the 500 kV tie line. Study case base flows on the 500 kV tie line are approximately 1300 MW and increase to approximately 1450 MW with the additional 1000 MW import. The phase angle at Richmond with the additional 1000 MW import is 37°.

Studies showed that PEC system response to the additional 1000 MW on the Duke interface is approximately 37% of the additional 1000 MWs with the Richmond-Newport 500 kV tie-line directly carrying approximately 15%. Solutions were tested that were projected to reduce the loading on the 500 kV interface with Duke.

With a regional perspective, potential transmission solutions were narrowed down to those thought to best reduce the 500 kV import flows into PEC's Richmond 500 kV Station. The results below in Table 1 show the impact on phase angle for seven different projects that were projected to provide the most improvement to the phase angle. As shown below, the best solution was found to be the Cumberland-Richmond-(Duke)Newport 500 kV Line, which would be a new tie line between PEC and Duke Energy. The next best solution in the study was the Cumberland-Richmond–(Duke)Pleasant Garden 500 kV Line which is comparable in length and cost but produces less reduction to phase angle.

Table 1: Impact of Alternatives on Richmond Phase Angle

Transmission Alternative	Richmond 500 kV Angle (Open Terminal)
No Project	37°
Person-(AEP)Axton- 500 kV Line	34°
Person-(VP)Clover 500 kV Line	36°
Durham-(AEP)Axton 500 kV Line	33°
Durham–(Duke)Parkwood 500 kV Line	34°
Cumberland-Richmond–(Duke)Pleasant Garden 500 kV Line	28°
Cumberland-Richmond-(Duke)Newport 500 kV Line	15°

Cost

The Cumberland-Richmond-(Duke)Newport 500 kV Line would be approximately 145 miles in length with roughly 50 miles located in the Duke Energy service territory. Also, 25 of those 50 miles in Duke's territory would be located in South Carolina with the remainder of the line located in North Carolina. It is estimated that the average cost per mile of building this line would be $2 million, therefore, the 145 miles of line would cost approximately $290 million (PEC and Duke). Other underlying transmission expansion to existing infrastructure would be necessary to distribute the power flows internal to the PEC transmission network. An estimate of the additional PEC transmission and its cost is provided in Table 2. This additional expansion is estimated to cost in the neighborhood of $60 million. It is expected that this new 500 kV tie-line would also necessitate additional upgrades to Duke Energy's transmission system. While PEC has met and shared this issue with Duke Energy, estimates of Duke costs for other upgrades are not provided in this report. The total costs of the new 500 kV interconnection and additional PEC internal transmission upgrades would be approximately $350 million not including additional Duke Energy expansion requirements.

Table 2: Additional PEC Internal Transmission Expansion

Other Issues	Potential Solutions	Cost
Wake 500/230kV banks	Up-rate Wake 500/230kV Banks	$20M
Richmond-Rockingham 230kV	Richmond-Rockingham 230kV #2	$5M
Durham-Cary Regency Park 230kV	Harris - Durham 230kV	$15M
Sutton-Castle Hayne S. 230kV	Up-rate Sutton-Castle Hayne S. 230kV	$2M
Falls 230/115kV Bank	Add Falls 230/115kV Bank #2	$10M
Method-East Durham 230kV	Loop E. Durham-Method 230 kV into Durham 230	$3M
Harris LOCA Voltage	TCUL-Aux Transformers Harris Plant	$5M
	Estimated Additional Cost	**$60M**

Schedule

The schedule to complete this 500 kV line was developed based on PEC's recent experiences in constructing lower voltage transmission as well as other known industry experiences in building EHV lines. Table 3 shows an estimate of the time schedule to construct this 500 kV tie-line. Based on this 9 to 12 year estimate, the earliest possible in-service date would be in the range of 2013 to 2016.

Table 3: Schedule

Event	Time Estimate
Coordination with Duke Energy	1 year
Siting / Permitting	2-5 years[2]
Survey	0.7 years
Acquire ROW	2.0 years
Clear ROW	1.0 year
Foundations	0.5 years
Construction	2.0 years
Total	9-12 years

Risks

There are many risks that could impact the completion of this 145 mile 500 kV project. In addition to federal requirements, construction of this 145 mile 500 kV project will involve two states and therefore two state regulatory commissions. Potential risks associated with regulatory approvals, public opposition, ROW acquisition and construction could increase the time required to complete this project and result in a cost higher than the current preliminary estimate.

Summary

This report is a result of a continuing effort to scope a possible solution to the PEC eastern control area import limitation. PEC has met with and held several discussions with Duke Energy on this issue. PEC is continuing to study the situation.

[2] AEP's Jackson Ferry-Wyoming 765 kV line required 12 years to permit