



June 15, 2007

Via Email

PJM Board
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497

Re: *Transmission Advisory Committee Transmission Upgrade Project Recommendations*

Dear PJM Board:

On May 3, 2007, PJM Interconnection, LLC staff ("PJM") met with stakeholders in the Transmission Advisory Committee ("TEAC") to discuss transmission upgrade projects that PJM staff is recommending to the PJM Board of Managers ("PJM Board") to be included in PJM's Regional Transmission Expansion Plan ("RTEP"). Pursuant to the TEAC charter, PJM members are permitted to submit written comments to the PJM Board in connection with the RTEP projects. Constellation Energy Group Companies ("CEG"), on behalf of its subsidiaries, Baltimore Gas and Electric Company ("BGE"), Constellation Energy Commodities Group, Inc., Constellation NewEnergy Group, Inc., and Constellation Generation Group, LLC, welcomes the opportunity to provide meaningful feedback to management and the PJM Board and accordingly hereby submits the following comments:

1. Analysis. CEG is concerned that certain necessary information and basic assumptions need significant improvements. Without these improvements, incorrect decisions may be made which may result in significant long term consequences.
 - a. CEG is concerned with the "volatility" of the analysis. There is no question that modeling the grid is an imperfect science, but precisely for that reason it is important that PJM refine to the greatest extent possible the information it relies on to make transmission upgrade recommendations and conduct reliability pricing model ("RPM") auctions. As noted in BGE's presentation at the Town Hall at the PJM Annual Meeting on May 2, 2007, reliability violations with respect to lines at 500kv and above were picked up in PJM's five year analysis, but overlooked in the previously issued 15 year analysis. Members were last year informed that the constraints that this line would relieve were not overloaded until 2018-2019. However, at the most recent TEAC meeting, members were informed of a significant change in analysis in which PJM staff now proposes a new 765kv project in 2012, claiming that a violation will occur much sooner, necessitating a service date for a 330 mile transmission. Many members at the TEAC meeting commented that a target date of 2012 was, at best, extremely aggressive and perhaps, at worst, unrealistic. Although CEG recognizes and supports the need for

15 year planning, we are concerned about efforts to expand the scope of PJM's planning process when these types of significant issues become apparent with only a short amount of notice.

- b. With respect to the newly proposed transmission line, CEG also is concerned that PJM staff's analysis is incomplete in that it does not address the costs or the impacts on the system of the necessary "off-ramps" of the proposed project. No analysis has been made available on the impacts of connecting a 765kv line to lower line voltages to ensure that power can actually be delivered into the constrained regions in which consumers would be paying for the 765kv upgrade. In addition, PJM staff has not presented any analysis regarding the impact of such an additional line on congestion. It is conceivable that whether intended or not, lower voltage lines could be significantly overloaded with the addition of a higher voltage system, thereby actually *increasing* costs to some consumers.

- c. CEG appreciates the analysis and information PJM has been providing through the TEAC; however, the information provided to date is not sufficient to support generator or demand response investment decisions, which can also effectively provide solutions for reliability violations. PJM members have not been provided certain critical information necessary to make such investment decisions, such as the impact on the global (*i.e.*, western and eastern PJM) and zonal capacity emergency transfer limits ("CETL") of each specific transmission upgrade. This information directly affects the assessment of what amount of generation and/or demand response may solve the reliability problems at a more efficient cost. While we appreciate that this analysis was supposed to be included as part of the "scenario planning," only a few larger projects have had this information presented through TEAC. This information needs to be made publicly available for all projects. In addition to providing each project's impact on CETL within the planning window, PJM should make available the data and tools for market participants to conduct CETL analysis themselves, including:
 - i. Cases constructed to conduct each sub-area test including the mean generator dispatch (*i.e.*, the 2012 SWMAAC CETL case);
 - ii. All supporting files including contingency lists, monitored elements lists and MUST subsystem files;
 - iii. Any and all tools developed by PJM to conduct the analysis (*i.e.*, PSSE/MUST add-ons that include the logic to expedite the analysis);
 - iv. Complete descriptions of each upgrade in PSSE/MUST format (.idev files); and
 - v. Training on how to conduct the analysis – including manual steps taken to relieve overloads when they are reached (*i.e.*, redispatch).

The fluid nature of the RTEP requires that developers conduct on-going analyses with each new list of announced projects. There already is sufficient market uncertainty regarding forward fuel costs, market structure, emissions regulations, generator investment decisions, and timing of projects. The impact of transmission projects on CETL should be well-known and understood and should not fall in the list of “other market uncertainty.”

- d. Finally, many stakeholders have raised concerns both at proceedings before the Federal Energy Regulatory Commission and in the PJM forum about PJM’s current use of DFAX in its analysis. There seems to be near universal agreement that this approach is in need of reform.

2. Compatibility with RPM. CEG also is concerned with the need to ensure coordination between RTEP and RPM. In support thereof, CEG states that:

- a. Companies have indicated a desire to invest in generation in various locational deliverability areas (“LDAs”) and have entered PJM’s interconnection queue following the first RPM auction’s results, based on an understanding that significant transmission was not going to be required until 2019. Assuming that it will take at a minimum two full years to build a gas unit, let alone a few years longer for a nuclear or coal unit, any new unit that comes into a LDA will desire to receive adequate revenues (based on LDA premiums) for about two years, until the large transmission upgrade project equalizes prices across LDAs. While investors appreciate that there is no guarantee of investment recovery, it would simply be imprudent to make an investment that had no opportunity to recover its fixed costs after two years. These investors have no guaranteed recovery mechanism and bear all the risk of making good and timely investment decisions. On the other hand, transmission owners may receive full recovery on their investments but it is unlikely that they will have an obligation to any customers in the event that investment construction is not well managed financially or delivered on time. In this way, transmission owners do not face the type of long term revenue uncertainty as investors in new generation. An unanticipated acceleration of large transmission projects has the potential to undermine commitments to invest in needed capacity. As such new transmission projects may reduce the potential long term revenues of new generation. PJM should more closely consider such risks by ensuring proper coordination between RTEP and RPM.
- b. For example, unlike in RPM where merchant transmission and new generation and demand response have milestones to meet and are responsible financially for their failure to meet them, there is no similar obligation on transmission owners building reliability upgrades. PJM has stated that it must include these upgrades in any reliability modeling, which presumably includes RPM modeling. If these upgrades are not complete in a timely manner, then the wrong market signals will have

been sent for resource adequacy *e.g.*, LDAs may look unconstrained whereas without the transmission upgrade they are constrained, and it is possible that PJM may have a reliability problem on its hands. The interaction between RPM and completing transmission lines on time became particularly important when feasibility of the service date for 2012 765 kV was widely questioned at the most recent TEAC meeting. The RTEP process does contemplate deferring or even eliminating transmission projects when appropriate. However, there are no specific guidelines (other than the guarantee to transmission owners to recover costs incurred through any date of deferment or termination) for when such an event could happen. So, for example, it is simply unclear from a process point when a new generation resource might be included in any Baseline modeling, and how the transmission owner or the generator will be informed of any project deferments or terminations.

In conclusion, CEG makes the following recommendations to the Board:

- i. PJM must continue to improve its analytical modeling tools;
- ii. PJM must make publicly available certain information regarding impacts of transmission upgrades, as outlined above;
- iii. PJM must ensure better integration of RTEP and RPM; and
- iv. PJM must provide clarity for how new projects will be modeled into RTEP and the impacts on reliability projects.

Very truly yours,

/s/

Divesh Gupta
Counsel
Constellation Energy Group, Inc.
111 Market Place, Suite 500
Baltimore, MD 21202
(410) 468-3468
divesh.gupta@constellation.com

*On behalf of
Constellation Energy Commodities Group, Inc.
and Constellation NewEnergy, Inc.*