ODEC and AMP sincerely appreciate the time and effort expended by the Mid Atlantic Transmission Owners to address the questions and issues raised from the December 8, 2015 Mid Atlantic Sub Regional Meeting. The discussion during the January 22nd meeting was a good first step. Our goal is to assure the Local Plans provide an effective means for stakeholders to understand the criteria, assumptions and models used in developing the Plan and to provide stakeholders a meaningful opportunity to review and provide written comments prior to finalization of the Local Plan.

ODEC and AMP have reviewed our notes from the meeting and offer some additional comments and questions based on the discussion. Additionally, we have looked at the PSEG slides (which were not covered) and offer some comments/questions on them.

General:

The "Reliability" Presentation was not covered; what facilities in that slide deck are different from the individual TO presentations by PPL, PHI and PSEG?

During the January 7th TEAC, we considered addressing the additional PPL Supplemental Projects presented during the January 22nd meeting. ODEC and AMP submitted two additional sets of questions prior to the 22nd. When will the second set of questions related to those projects be addressed?

As a reminder from our preliminary questions and comments, it would be helpful if the cost estimates included in the presentations only included the transmission costs, and excluded any distribution facility costs or customer related direct interconnection or facility costs.

Specific:

PHI

1. PHI did a nice job presenting additional information and responding to questions. Serving our Nation's Capital is a significant job. Waterfront, Mt Vernon and New Harvard have apparently been conceived as part of a holistic, long range plan. Waterfront is an immediate need facility; Mt. Vernon and New Harvard are still in preliminary engineering. These projects are enabling PHI to replace obsolete facilities (as opposed to simply rebuilding these facilities) with new infrastructure to meet future needs.
2. Would like to hear more about the future 230 kV substation referenced
3. It was useful to hear about some of the factors going into the decision-making process. More written descriptions of the decision-making process and alternatives considered, including cost, would be helpful.
4. Would like to see PHI's distribution planning guidelines. This information would support the growth assumptions as well as document applicable reliability tests (N-1).

5. Would like to break out and separate transmission and distribution costs.
6. Would like to discuss network facilities that do not support network through-flow. Would like to better discuss the concept of network flows on Supplemental projects, PJM's role in evaluating such projects and the statement made by PJM that "PJM will use flexibility to optimize the system." This is the first Supplemental Project that we are aware of that creates a new network path. In addition, it has PARs on these lines to control the flows. PARs are expensive and cause operational concerns and opportunities. To have them installed via a Supplemental Project with little or no input from PJM is problematic to AMP and ODEC.

PPL

1. PPL also did a nice job preparing for the meeting and describing the thinking behind its proposed projects.
2. Would like to see a copy of the PPL Practices and Principles documents. What is the actual title of this document? How is this document updated? Does this document contain PPL's latest specifications?
3. Would like more detail on how PPL identifies and prioritizes which facilities to replace. It is clear that a number of factors go into the decision; at the end of the day with limited resources, how does management chose between competing projects?
4. While PPL has a standards group to determine the most appropriate current PPL design standards, it is still unclear how PPL decides what capability is required for facilities replacing aging infrastructure.
5. We need more detail regarding PPL's concerns with line tapped transformers at local substations. PPL quoted PJM Manual 7, yet this is still not PJM or PPL criteria.
6. We need more detail in determining how performance is measured, including relative levels of improvement in outages.
7. Installation of new physical security measures for old substations should be PJM criteria.
8. PJM's RTEP process includes a reevaluation of selected RTEP facilities. To the extent a facility that has not yet been placed in-service and PJM determines through a later evaluation that the facility is no longer needed, for example due to a lower projected load, PJM will terminate the project and remove it from the RTEP. Does PPL have a similar process, especially for long lead time projects, with respect to it supplemental project planning process?
9. In the supplemental planning process does PPL consider the potential removal of aging facilities without replacement? For example, building new local facilities at a different location and removal of the existing facilities.

10. When will PPL address the second set of questions from the January 7 TEAC?

PSEG

1. **Slide 2**:
    a. Good background. Need to better explain so stakeholders understand how PSEG uses their 26kV system (distribution and support for transmission system??)
    b. Cost recovery for 69 and 26KV systems: Assume 69kV is transmission and FERC and 26kV is distribution and State
    c. PSEG says 26kV near end of life…proposal is to rebuild at 26kV or did PSEG look at higher distribution voltages for rebuilds?
2. **Slide 3**:
    a. What are the PSEG reliability criteria and how are they different from the criteria that is identified, but not detailed on this slide
        i. What is PSEG's maximum allowable load drop? Is this not a reliability criteria?
        ii. Does PSEG have performance criteria or guideline? If so, please share these so we can better understand your drivers.
        iii. What are the PSEG standards mentioned in this slide? Please provide them.
    b. How does PSEG view the improving and maintaining their distribution system in terms of impacts to their transmission system maintenance and design? More details on this are needed
    c. Modernizing to improve operational performance makes sense to me. Does this apply to transmission or distribution? Gets back to cost recovery between T and D.
3. **Slide 4**:
    a. First bullet, you say PSEG criteria includes both T and D violations. Please provide the Transmission and Distribution criteria used by PSEG.
    b. Need to better understand PSEG's decision on improving the 26kV performance and capacity as it impacts the 69kV system of PSEG.
4. **Slide 5**:
    a. Does PSEG have specific criteria or guidelines on SAIDI/CAIDI/MAIFI for their system? If so, it is based on system voltage level? Please provide. If not, they how does PSEG determine when an asset needs replacement, would it be based solely on age or health assessment rather than its performance?
    b. How does PSGE prioritize replacement of it Aging Infrastructure? Seems like assessment or performance are the two general categories for prioritization.
5. **Slide 6**:

a. Performance is considered, this seems reasonable since the industry guidance is just that, guidance. PSEG's actual performance will be different.
b. How does PSEG factor in or consider 'future system requirements' when you decide on the ratings for replacement facilities? How far in the future does PSEG look for future system requirements? Are other wholesale loads considered during this analysis?
c. Standard ratings for 69kV lines are good to have, does PSEG ever allow non-conductor equipment to limit a new, replacement 69kV line?
d. How does PSEG incorporate the needs of their distribution system when looking at 69kV facility replacements? Load growth only? Other factors?

6. **Slide 7**:
    a. Seems to be lacking some additional explanation on the first two bullets:
        i. What other solutions were looked at? It appears that PSEG is upgrading their 69-26kV switching stations, I would call these distribution feeder stations.
        ii. So generally, the PSEG 26kV needs upgrading and PSEG has some load pockets that need a new 69kV source to feed the load pocket if I am understanding the issues behind these projects.
        iii. PSEG is proposing some new 230-69kV stations, it is not clear why these are needed? If it is not enough to add 69kV stations, then since the 69kV lines are networked, some of these project should be baseline projects. Unless, PSEG is upgrading these 69kV line before they are needed to be upgraded via TO/PJM/NERC criteria. Why would PSEG do this? Other PSEG criteria/guidelines, please provide.
7. **Slide 9**:
    a. Overload verses which criteria? Please provide the PSEG criteria. Why it this not a TO FERC 715 criteria?
8. **Slide 10**:
    a. Replace conductor with what size, again, need the criteria to make this decision, please provide.
    b. Assume PSEG is not including 26kV protection control cables in their transmission costs of $6.5 million, please confirm.
    c. Please explain the spilt between PSEG and Generation Owner
9. **Slide 13**:
    a. Not clear on the capacity problem, old station seems reasonable, but what is overloaded, the 26kV distribution or the transmission feed to these two stations at 69kV?
    b. Solution seems reasonable, but unknowns on problem make it difficult to get the full picture. Is the 69kV system overloaded or under capacity? If so, when, by how much and by which criteria, standard

TO/PJM/NERC criteria or PSEG criteria? If PSEG criteria, please provide the details on the violation.

   c. Seems like stations are very, very old: no room to expand or rebuild. Solution is for a new station, seems reasonable. So why 230kV and why is this not Aging infrastructure-what is the violation/criteria?
   d. Does cost estimate include Distribution costs? Should only be transmission costs.
   e. Would be very useful to provide a one line of this area now and have the project to better understand the scope. Is PSEG still using 26kV as its distribution voltage in this area?

10. **Slide 15**:
    a. Not clear why 26kV service not sufficient. Not enough transformer capacity, not enough circuit capacity or enough circuits? Assume PSEG cannot add more circuits so something has to be done.
    b. PSEG distribution needs more capacity in this area, good problem statement. Expansion of the existing stations is not feasible due to space restrictions and age. Therefore, PSEG need a new station in this general area.
    c. Again, one lines would be useful.
    d. Why the need for 230kV? Why not increase the capacity of the 69kV system in this area? Is this not feasible, why?
    e. Should the new 69kV line be a baseline project? Guessing the system might not meet TO./PJM/NERC criteria if this new 69kV line is not built. If this is not the case, then why the need for it? What criteria or guideline is being violated?
    f. Costs- is this all Transmission costs? Please provide Transmission costs only.
11. **Slide 17**:
    a. Provide the PSEG N-1-1 criteria that is being violated. Is this PSEG criteria filed at FERC on Form 715?
    b. New source sounds good to have, aging infrastructure is reasonable.
    c. Why the 230kV need? Violation/criteria/guideline from PSEG?
    d. Are the two lines necessary for TO/PJM/NERC criteria? Is at least one line necessary for the same criteria? If No to both, then why the new line? PSEG criteria/violation, if so, then please provide more details.
    e. Costs: T or D or both? Only want T costs.
12. **Slide 19**:
    a. Provide more details on the PSEG N-1-1 criteria and how it is being violated here.
    b. Why the new for 230kV source? Criteria or violation, provide details?
    c. Are all of the new 69kV lines needed? Criteria or violations? Are any of them needed to meet TO/PJM/NERC criteria? Baseline vs. Supplemental issue
    d. Aging infrastructure makes sense

   e. Which one of these stations is the ‘existing switching station’ mentioned in the Alternative Considered? A before and after one line would be very, very useful in understanding this.
   f. T vs. D costs, provide transmission costs only
13. **Slide 21**:
   a. Why the need for new 69kV lines? PSEG criteria, please provide more details.
   b. Are either of the new 69kV line needed for TO/PJM/NERC criteria? Should one be a baseline project?
   c. T vs. D costs, provide only Transmission costs.
14. **13kV Projects**:
   a. Are these Transmission projects, is PSEG recovering these costs thru your FERC transmission rate? If Yes, please explain why as everywhere else these would be distribution facilities
   b. T vs. D Costs, show only Transmission costs
15. **Transformers**:
   a. Are any of these costs being included in your transmission rate? Please remove any that are not recoverable
   b. For the transformers with secondaries at transmission voltage, we assume these are transmission assets and recoverable at PJM/FERC.
   c. Seems reasonable to have emergency spares for critical transformer like a 345-138kV transformer.