September 16, 2019

Ake Almgren, Chairman PJM Board of Managers
Susan J. Riley, Interim President and CEO
PJM Interconnection, L.L.C.
2750 Monroe Boulevard
Audubon, PA 19403

PJM Board or Managers
c/o Ake Almgren, Ph.D., Chairman
2750 Monroe Boulevard
Audubon, PA 19403

Dear Chairman Almgren, President Riley, and the Members of the Board,

The Consumer Advocates of the PJM States (CAPS) hired Continuum Associates (Continuum) to perform a detailed assessment of the planning, approval, and oversight process associated with supplemental transmission projects in the PJM region. Attached is the Report.

As many stakeholders are aware, the costs associated with supplemental projects within the PJM region have increased significantly. Continuum noted that the total capital expense associated with these projects is projected to increase from $3 million in 2013 to $3.9 billion by 2020.[1] A total of 1,094 supplement projects are proposed now, and many have in-service dates through 2040.[2] Undertaking this effort, CAPS members were seeking more insight into how supplemental projects are incorporated into PJM's regional planning efforts, the magnitude of supplemental projects, the standards used to review projects, and perhaps most importantly, where jurisdiction to approve or review supplemental projects rests.

Continuum's Findings

Continuum found that while the planning criteria used by transmission owners and PJM are generally consistent, there is inconsistency in how required details are reported for specific projects.[3] There are often minimal to no details on criteria exceptions or deviations from generally accepted standards. Where transmission owners make reference to criteria that may be more stringent than what is required by

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[1] Final Report, Expert Consultation on PJM Supplemental Transmission Projects: Standards and Oversight (Report), September 4, 2019, at 1.
[2] Report at 6.
[3] Report at 4.

federal law,[4] no details are provided on these more stringent criteria. Moreover, Continuum concluded many transmission owners are not regularly – or even periodically – updating their standards.[5] Most importantly, Continuum also concluded that PJM performed little to no oversight on how these standards and planning criteria were applied and incorporated into the regional transmission planning process.[6]

In reviewing the PJM planning process, Continuum noted that many CAPS members had little or no insight into the supplemental project pipeline, that is, how projects were conceived and designed.[7] Meetings with transmission owners and Commission staff regarding supplemental project planning happen sporadically and without any formal requirement.[8] As a result, there is very little chance for advocates to receive meaningful information or provide feedback as supplemental projects are planned.[9] Continuum found that once a supplemental project was incorporated into the regional planning process there was no additional analysis. PJM does not conduct an independent needs assessment for supplemental projects, nor does PJM study whether a project already planned could address a different system need. As a result, supplemental projects in states which do not require any certificate of convenience or need (CPCN) have no needs assessment applied to them at any point.[10] Further, this means no assessment of solution options and no assessment of cost prudency occurs.[11]

Continuum found very similar issues at the later planning stages as well, noting the lack of any requirement to assess alternatives to proposed projects or provide efficient ways for stakeholders to offer feedback.[12] They also identified a number of transparency-related issues within the PJM regional planning process, from minimal and vague information provided by project sponsors to missing or outdated information, and a failure on PJM's part to ensure the information is adequate.[13] The report specifically calls out the lack of insight and transparency transmission owners provide throughout the "pipeline" process,[14] and the lack of communication from transmission owners about their intended plans for development.[15]

CAPS Member Responses

Continuum makes several suggestions to enhance and improve oversight of supplemental projects. Members are considering adopting some – if not all - of these options:

- Improving the PJM stakeholder process and better implementation of the PJM Attachment M-3 process.
- Periodic and on-going access and review of supplemental project information, and access to the transmission owner staff developing the projects, from the conceptual stage.

[4] E.g. standards imposed by the North American Electric Reliability Corporation (NERC). Report at 4.
[5] Report at 4 (noting for example that Duke Energy last updated its planning criteria in 2011).
[6] Report at 5.
[7] Report at 14.
[8] Report at 14.
[9] Report at 14.
[10] Report at 15.
[11] Report at 15-16.
[12] Report at 17.
[13] Report at 16-17.
[14] Report page 14, 19.
[15] Report page 14. (Point 2. Minimal Communications during the Conceptual Planning Phase).

- Create appropriate levels of oversight at the state level
- Improve expertise in the transmission planning area and address any resource availability constraints among advocates and state commission staff.
- Ensure adequate oversight during the implementation phase of supplemental projects.
- Consider use of emerging technologies to address system needs.

It would be helpful if PJM works with stakeholders to develop a standardized planning criteria that includes supplemental transmission projects in the PJM regional transmission plan.[16]

The report raises a number of concerns for the Consumer Advocates. In particular, the report finds the level of transparency and oversight for supplemental projects is woefully lacking. CAPS members are concerned that without the application of certain standard planning criteria, the transparent sharing of project data, and the opportunity to provide meaningful feedback on proposed needs and solutions, the costs associated with supplemental projects will continue to rise. Moreover, end-use customers may well find themselves paying for projects to address needs identified using outdated or incomplete information, and with project costs higher than customers would have paid had non-wires alternatives, emerging technologies, or existing distributed energy resources been deployed. PJM's competitive energy markets have worked to deliver savings to customers and provide pathways to promote new technologies. CAPS members believe increased transparency and competitive planning can deliver similar results for transmission.

When considering the report's findings and ongoing discussions regarding updating PJM Manual 14b, the Advocates are concerned that it will be increasingly hard for PJM to regionally plan. For instance, it will be hard to identify baseline solutions that also address the need underlying a supplemental project if PJM is unable to even see, assess, or verify the underlying need. These supplemental projects are included in the RTEP so easily that it creates an issue for PJM and all stakeholders because much of the data underlying their regional plan is not verifiable. PJM oversight and review of these projects would permit identification of supplemental projects that could displace reliability projects. The transmission grid is dynamic, and it is essential that PJM adequately assess grid reliability with specific information and analyses about supplemental projects.

As a result, transmission planning will remain a top priority for the foreseeable future. Establishing clear lines of authority over supplemental projects, and clear lines of sight on system needs, solutions, project costs, and project benefits, will be essential to meeting consumers' demands placed on the region's transmission system in coming years.

CAPS thanks Continuum Associates for its work on this effort, and looks forward to working with PJM stakeholders, staff and Board of Managers on these very important issues.

Sincerely,

Kristin Munsch

Kristin Munsch
President, Board of Directors

[16] Public Utilities Commission of Ohio, July 30, 2019 recommendations to PJM.

FINAL REPORT

Expert Consultation on PJM Supplemental Transmission Projects: Standards and Oversight

Prepared for:
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September 13, 2019

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DISCLAIMER

This report was prepared by Continuum Associates LLC (Continuum Associates) for Consumer Advocates of the PJM States, Inc. (CAPS). The work presented in this report represents Continuum Associates' professional judgment based on the information available at the time this report was prepared. Continuum Associates is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. Continuum Associates MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

List of Abbreviations and Acronyms

PJM Pennsylvania-New Jersey-Maryland Interconnection or PJM Interconnection, LLC

CAPS Consumer Advocates of the PJM States, Inc.

TO Transmission Owner

PC PJM Planning Committee

TEAC PJM Transmission Expansion Advisory Committee

STP Supplemental Transmission Projects

CAPEX Capital cost or Capital Expenditure estimated for a transmission project, specifically a Supplemental Transmission Projects in the context of this report

CA Continuum Associates LLC [Consultant to CAPS for this engagement]

B Used to denote one billion United States Dollars. Equivalent to $1,000,000,000

M Used to denote one million United States Dollars. Equivalent to $1,000,000

CPCN Certificate of Public Convenience and Necessity

NTA Non Transmission Alternatives

CY Calendar Year

OATT PJM's Open Access Transmission Tariff

ROW Right of Way

1. Executive Summary

Continuum Associates LLC (Continuum Associates) was retained by the Consumer Advocates of the PJM States (CAPS) to perform a detailed assessment of planning, approval, and oversight process associated with Supplemental Transmission Projects (STPs) in PJM. The intent of the Continuum Associates' mandate was to perform a detailed and thorough assessment of the PJM planning process as it relates to STPs proposed in PJM. Additionally, Continuum Associates identified the shortcomings with the oversight process associated with STPs, both at PJM and State Commissions that review and approve power transmission projects in their jurisdictions. Finally, Continuum Associates developed recommendations on enhancing and improving the overall oversight for STPs.

Over the past few years, the numbers of STPs proposed in PJM have increased significantly. Based on information collected from PJM's website, the CAPEX of STPs built and commissioned into service in 2013 totaled about $3M. In 2020, the CAPEX of STPs expected to be built and commissioned is expected to be approximately $3.9B, an increase of almost 1,300 times. As the first step of its engagement, Continuum Associates completed an assessment and review of planning standards and guidelines used by PJM TOs to plan and conceptualize transmission projects. This is covered in Section 2 of this report. A comparative assessment of the planning standards is provided in Appendix A of this report.

A thorough assessment of STPs currently proposed and completed in PJM's service territory was completed for all TOs to assess the numbers and CAPEX budget of all STPs proposed in PJM. Data on STPs was collected from PJM's website and further scrubbed and organized to provide insights on different classifications of STPs. This included STPs across different PJM regions, across different PJM TOs, and different types of transmission projects amongst other pertinent categories. This information is presented in detail in Section 3 of this this report and Appendix B provides graphical details on our findings. STPs proposed until the expected in-service year of 2040 were assessed. Section 4 of the report specifically focuses on the STPs that were completed or proposed to be completed in 2018. Appendix C provides further graphical details and illustrations on STPs proposed to be completed in 2018.

Section 5 of the report details the issues with STPs from initial conceptualization to final commissioning. Continuum Associates studied the complete life-cycle of a STP, from conceptual planning to its implementation and realization. Issues and shortcomings with each phase of development of a STP are detailed in Section 5 with particular focus on the issue of lack of oversight.

In an effort to find recommendations to address the issues identified with the overall life-cycle of a STP and the issue of lack of oversight, Continuum Associates completed interviews with State Commissions and Consumer Advocates for PJM states. A summary of findings and issues related to oversight of STPs collected through these interviews is presented in Section 6 of this report. Section 7 details the concrete, impactful, and readily implementable recommendations for the Consumer Advocates and the State Commissions that should be implemented to enhance overt oversight of STPs proposed across the PJM footprint.

2. Review of Planning Standards and Guidelines Used by PJM Transmission Owners for Supplemental Transmission Projects

Continuum Associates completed a comprehensive review of planning standards, planning criteria, interconnection requirements, and other guidelines used by various PJM Transmission Owners for transmission projects. These standards and criteria were specifically reviewed to evaluate how they were or are being applied to study and evaluation of Supplemental Transmission Projects (STPs) proposed by various Transmission Owners within the PJM footprint. The intent of this exercise was not to evaluate the validity of a specific planning criteria and standard as it may apply to the conceptual or final planning of a PJM Supplemental Transmission project or qualitative assessment of a planning criteria being used by PJM TOs for PJM Supplemental Transmission Projects. The intent of this exercise was rather to identify the reasonableness of planning standards and criteria currently in use by different TOs. Reasonableness of planning criteria and standards used by various TOs were assessed to determine if any of them may be resulting in STPs with excessively large scopes of work and capital costs for STPs. Continuum Associates' intent was also to evaluate whether efficient planning practices were being following while planning for STPs.

Appendix A lists a high-level comparative assessment of planning criteria and standards evaluated for various PJM TOs. Since PJM TOs do not differentiate a transmission project based on different categories such as STP or Baseline Reliability, the TO planning criteria evaluated also applies to STPs.

It should be noted that not all TOs publish their planning criteria on PJM's website in sufficient detail to perform a thorough comparative assessment. Planning standards and criteria are also not published in a consistent manner, i.e. not all of them address all aspects of planning across different voltage levels and categories of power transmission equipment such as overhead transmission vs. underground transmission and so on. Some of the TOs only provide a cursory reference to planning standards and criteria that they are using. As an example, some of the TO planning standards just refer to PJM's Manual 14B and NERC planning criteria, such as the NERC TPL TPL-001-4 as a reference for planning their own transmission infrastructure needs, without providing any further details. Considering lack of sufficient details in planning standards and criteria across all PJM TOs, a full and comprehensive comparative assessment between the planning standards cannot be completed as part of this work. It should also be noted that NERC Transmission Planning (TPL) criteria and other standards mentioned or referenced by TOs indicate only the minimum criteria that a TO needs to follow to avoid NERC criteria violation, and does not delve into details of good practices or efficient practices in transmission planning that should be applied. As a result, the NERC planning criteria only establishes a floor or minimum requirements for the purposes of designing and planning power transmission infrastructure. Transmission owners are not bound by any upper limits or requirements to plan their transmission infrastructure to be capital cost efficient, in line with good planning practices. A Transmission Owner can always plan or engineer its transmission network to a higher benchmark or standard based on its unique needs which it finds reasonable based on its own unique circumstances or customer needs. Such instances cannot be evaluated without performing a deeper and more detailed assessment of a need that may be driving a certain STP and the transmission solution proposed to address that transmission need.

Based on the limited assessment that we could perform for the TO planning standards and criteria, the following are our findings[1].

1. All TOs comply with NERC planning criteria, specifically the NERC TPL TPL-001-4 planning criteria. TOs with a footprint in PJM also specifically comply with PJM Planning Manual 14-B planning standards. Hence, all TOs are adhering to minimum planning requirements.

2. The transmission planning criterial and standards used by PJM TOs are generally consistent across the board for voltages 100 kV and higher. The primary or governing planning criteria in most cases is the NERC Planning Criteria NERC TPL TPL-001-4 and the PJM Planning Manual 14-B, and hence are largely consistent across the TOs.

3. Details – In many instances, TOs provide minimal details on their planning criteria, as is evident from the planning criteria published on PJM's website[2].

4. Inconsistencies in providing the required details pertaining to planning standards and requirements. The TOs have provided minimal to no details on criteria exceptions or deviations from generally accepted standards. Many TOs talk about more stringent planning criteria that they follow under certain circumstances. However, in many instances no details are provided on these more stringent criteria, except for referencing them.

5. Updates – TOs do not appear to be making regular or periodic updates to their standards, as provided to PJM. Some of the TO planning criteria has not been updated in years. For example, Duke Energy last provided an update on its planning criteria in 2011.

[1] Stability criteria used by different TOs was not evaluated as part of our work for CAPS, since the cost of transmission upgrades associated with stability related issues are significantly smaller compared to transmission upgrades required for powerflow related issues.

[2] https://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx

6. There is little to no PJM oversight or due-diligence on how and when the criteria are being submitted, or what is being submitted as part of the criteria. It appears that PJM does not enforce uniformity or minimum standards on the planning criteria that the TOs are submitting to PJM which are eventually published on PJM's website. TO planning criteria vary significantly on details and frequency at which planning criteria are published.

Our overall assessment of TO planning standards and requirements did not indicate any unreasonable standards. However, as noted earlier comparison of TOs planning standards and requirements cannot establish how reasonably such standards are being applied to STPs being proposed by Transmission Owners. Such assessment of reasonableness can be evaluated only by delving deeper into the details of a particular STP being proposed by a TO and comparison of transmission upgrades proposed as part of a STP with TO published transmission planning criteria. Such an exercise was outside the scope of our current phase of work with CAPS and also needs significantly more concerted effort. As part of recommendations to enhance oversight by the Consumer Advocates and the State Commission staff in section 6 of this report, we recommend that a thorough assessment of STPs being proposed be completed on a regular basis, with emphasis on ensuring that TOs are judiciously and reasonably planning STPs.

3. Status of Supplemental Transmission Projects in PJM Footprint[3]

We performed detailed assessments of all Supplemental Transmission Projects currently proposed in PJM footprint by PJM member TOs. The primary source of this information was the PJM portal. Continuum Associates also performed a scan of TO presentations for Supplemental Transmission Projects presented at the PJM PC, TEAC, and regional sub-committees to get a sense of type, cost, and volume of STPs that have been proposed by Transmission Owners.

Appendix B shows the details of our findings and various metrics on all STPs proposed across the PJM footprint.

Below are the highlights of our findings on STPs that have been proposed in the PJM footprint.

1. Total of 1,094 transmission projects are proposed across all categories, with proposed in-service dates extending into 2040.

2. Total capital cost of 937 projects proposed to be completed by 2040 is $15.7B. Total CAPEX of all projects proposed, over the same period is probably close to about ~ $18.5B - $20B.

3. Average cost of a supplemental project proposed in the PJM footprint, when calculated on the basis of all STPs proposed on the PJM footprint is about $16.8M.

4. There is a significant variety in the STPs proposed based on capital cost:

    a. Largest or most expensive project is a Transmission Hardening Program totaling $1,275B proposed by PSE&G. Expected to be complete by April 30, 2020.

    b. STPs as low as $100,000 are proposed by TOs.

5. Almost 157 proposed projects have no cost allocated to them. No CAPEX has been listed for these STPs on the PJM portal.

[3] Source of Information:

1. PJM Website (https://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx
2. Other publicly available sources such as meeting material published on PJM committee meeting portals
3. Material published on PJM's regional subcommittee meeting portals
4. PJM TEAC presentations – January 10, 2019 and February 7, 2019

6. Up to an estimated $2.63B[4] in STPs have no CAPEX budgeted, and hence may not be accounted for in total CAPEX ($15.7B) for all STPs. Actual CAPEX for all STPs proposed may be much higher.

Additionally, below is a snapshot of STPs that are currently under construction. The actual in-service date of STPs currently under construction may change as the projects are implemented and more up-to-date information is provided by TOs implementing STPs. The in-service date of STPs listed below is estimated to be between 2019 – 2025 (a six-year time period):

7. Total of 542 supplemental projects are currently under construction.

8. Total capital cost of 542 projects under construction is approximately $8.8B.

9. Average cost of a supplemental project under construction is $17.54M.

10. Actual CAPEX spend is most likely higher since almost 42 supplemental projects have no cost allocated.

11. We estimated that actual cost of supplemental projects under construction may be approximately around $9.51B, after estimating cost for 42 STPs that had no CAPEX cost allocated to them.

In January 2019 and February 2019, PJM presented additional insights on STPs proposed at the PJM TEAC. Below are additional insights from those presentations[5]:

1. By the end of CY2018, the total Supplemental Transmission Projects across PJM footprint topped $26B in CAPEX budget, an incremental increase of over $6B compared to Supplemental Transmission Projects proposed at the end of 2017.

2. 2018 saw the largest increase in Supplemental Transmission Projects at over $5.7B. The second largest set of Supplemental Projects in PJM was proposed in 2015, totaling about $5.1B.

3. Top three TOs proposing Supplemental Projects in PJM in 2018:

[4] Estimated based on the average cost of a STP; Average cost of a STP (approximately $16.8M) * Total number of STPs that have no CAPEX budget allocated on the PJM portal

[5] CAPEX and/ or cost numbers rounded to one decimal place, where applicable

a. PSE&G - $1.6B
b. AEP - $2.4B
c. ATSI - $511M
d. Top three TOs proposing Supplemental Projects in PJM since 2005:
    i. PSE&G - $9.1B
    ii. AEP - $6.2B
    iii. PPL - $3.1B

It should, however be noted that the number and scope of STPs remains dynamic and fluid through the planning and PJM stakeholder process. These projects change in scope and numbers frequently as evident from frequent updates by PJM of STPs on its portal. Hence the number and the total budget of STPs Projects presented as part of this report should be more viewed as an indicator of quantity and trend of STPS that are being proposed. The information presented here should not be used to evaluate merits of individual STPs.

Full details of our findings with graphical illustrations on all STPs proposed and under construction in PJM are provided as part of Appendix B of this report. Information presented here on STPs, currently proposed and under construction in PJM was sourced solely from PJM's portal and is subject to further updates based on periodic information provided by PJM TOs.

4. Supplemental Transmission Projects Planned and Completed in 2018[6]

Continuum Associates collected comprehensive data on Supplemental Transmission Projects that were proposed to be completed and were actually competed in 2018. The source of this data and information was the PJM portal. Extensive scrubbing and analysis on raw data collected from PJM's portal was completed to gain insights on Supplemental Transmission Projects that were proposed and completed in 2018.

Below is a snapshot of data that was collected and analyzed:

1. A total of 362 Supplemental Transmission Projects were proposed and planned to be completed in CY 2018. Total CAPEX for all planned supplements projects was $2.97B

2. A total 114 transmission supplemental projects were actually completed at a total CAPEX of $991.2M

3. Project realization (construction completed) rate for all STPs, on average was approximately 33.4 percent

4. There was a significant and varying variety in the STPs that were proposed and completed in 2018:
    a. Lowest cost supplemental project was $50,000 and involved installing a wave trap at an existing substation. Proposing TO was ComEd.
    b. Highest cost supplemental project was $156 M and involved building a 138 kV substation for four new 138 kV circuits. Proposing TO is PEPCO.

5. In terms of planned STPs, PSE&G had the largest CAPEX allocated to planned STPs at $838M

6. AEP had the second largest CAPEX allocated to planned supplemental transmission projects at $774M

[6] Source of Information:
1. PJM Website (https://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx)
2. Transmission Cost Information Center (TCIC) (https://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx
3. Other publicly available sources such as meeting material published on PJM committee meeting portals
4. Material published on PJM's regional subcommittee meeting portals

7. In terms of realized (construction completed) STPs, AEP realized the highest number of supplemental transmission projects at $26 M, at a realization rate of about 34 percent

8. PEPCO achieved a realization rate of 100 percent, completing construction of all supplemental projects that it had planned, at a total CAPEX of $156M

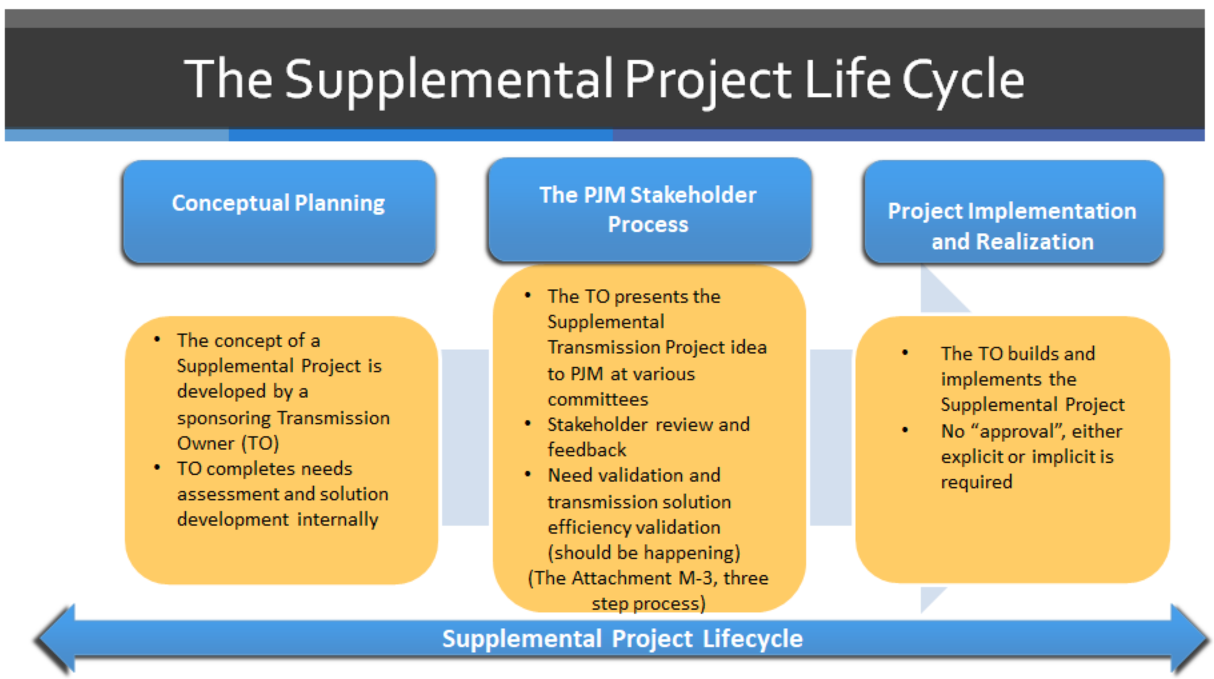
9. PSE&G realized supplemental transmission projects totaling $147M, a realization rate of about 17.5 percent

Full details of our findings with graphical illustrations are provided as part of Appendix C of this report. It should be noted that Continuum Associates could not verify the accuracy of these numbers with actual on-the-ground implementation of STPs. Information presented here was sourced solely from PJM's portal and is subject to further updates based on periodic information provided by PJM TOs.

5. Current and Known Issues with PJM Supplemental Transmission Projects

5.1 The Supplemental Transmission Project Life Cycle

Continuum Associates performed a thorough assessment of the life-cycle of a Supplemental Transmission Project, from the moment it is conceptualized by a Transmission Owner through the PJM stakeholder process and finally when it moves through the implementation or construction process. The overall process can be summarized graphically as shown in Figure 1.



Figur: PJM Supplemental Transmission Project Life Cycle

There were a number of issues that Continuum Associates identified with the life cycle of STPs during the course of our consulting engagement with CAPS. The overall STP life cycle can be broadly divided into the following three high-level steps:

1. Conceptual Planning
2. PJM Stakeholder Process
3. Project Implementation and Realization (construction and commissioning)

In the following section, we detail each of the three steps that complete the life cycle of a STP. Section 4.2 describes the issues with each of these three steps.

1. **Conceptual Planning**

   Conceptual Planning involves developing the concept of a STP based on developing or identifying transmission needs. The sponsoring TO analyzes the needs internally and develops a transmission based solution to the identified needs. The sponsoring TO should be using good utility practices and efficient transmission planning techniques to identify the most cost effective and efficient transmission solution to an identified needs. However, that is not happening uniformly across the board for all the STPs proposed by every TO[7]

2. **PJM Stakeholder Process[8]**

   The PJM Stakeholder process involves the sponsoring TO presenting the STP at various PJM committees and sub-committees. This involves presenting the identified need and the STP to mitigate the identified need at the PJM TEAC and sub-regional committee meetings. This is where significant changes, in terms of adhering to the PJM Tariff for STPs have taken place and have been pursued by PJM. PJM has started enforcing the three-step process and the timelines mandated for each step per the Attachment M-3 of the PJM OATT. However, the PJM stakeholder process still lacks a needs assessment and validation of a transmission solution proposed by a sponsoring TO[9]. PJM currently performs no validation of the need and no assessment of the proposed Supplemental Transmission Solution in response to an identified need. Such an assessment by PJM or another entity, such as the State Commissions or the Consumer Advocates should involve both assessment of efficacy and effectiveness of a proposed transmission solution and assessment of capital costs or CAPEX for the proposed solution. Ideally, this step should also evaluate if a non-transmission solution exists to an identified transmission needs, and if a non-transmission solution is more cost effective than the identified transmission need. More on our recommendations for NTAs is covered in section 6 of this report.

[7] American Municipal Power, Inc. performed an in-depth analysis of some of the Supplemental Transmission Projects proposed by PJM TOs, which indicated inefficient planning involving inadequate use of existing transmission network resources.

[8] Per recent changes to the Attachment M-3 process by PJM, stakeholders now have the opportunity to review assumptions and provide comments on assumptions used during the early planning stages of a STP.

[9] No needs assessment and validation of a transmission solution is performed by PJM or another independent stakeholder.

3. **Project Implementation and Realization**

Project Implementation and Realization follows the PJM stakeholder process described in step 2 above and involves the implementing and construction of the proposed STP. Per the current OATT, TOs do not need an approval, either explicitly or implicitly from PJM to proceed with the implementation. Sponsoring TOs are also not required to provide any feedback or reporting to PJM or PJM stakeholders once a STP has progressed to the Project Implementation and Realization phase.

5.2 Issues with the Overall PJM Supplemental Transmission Project Life Cycle – From Conceptual Planning to Project Implementation and Realization

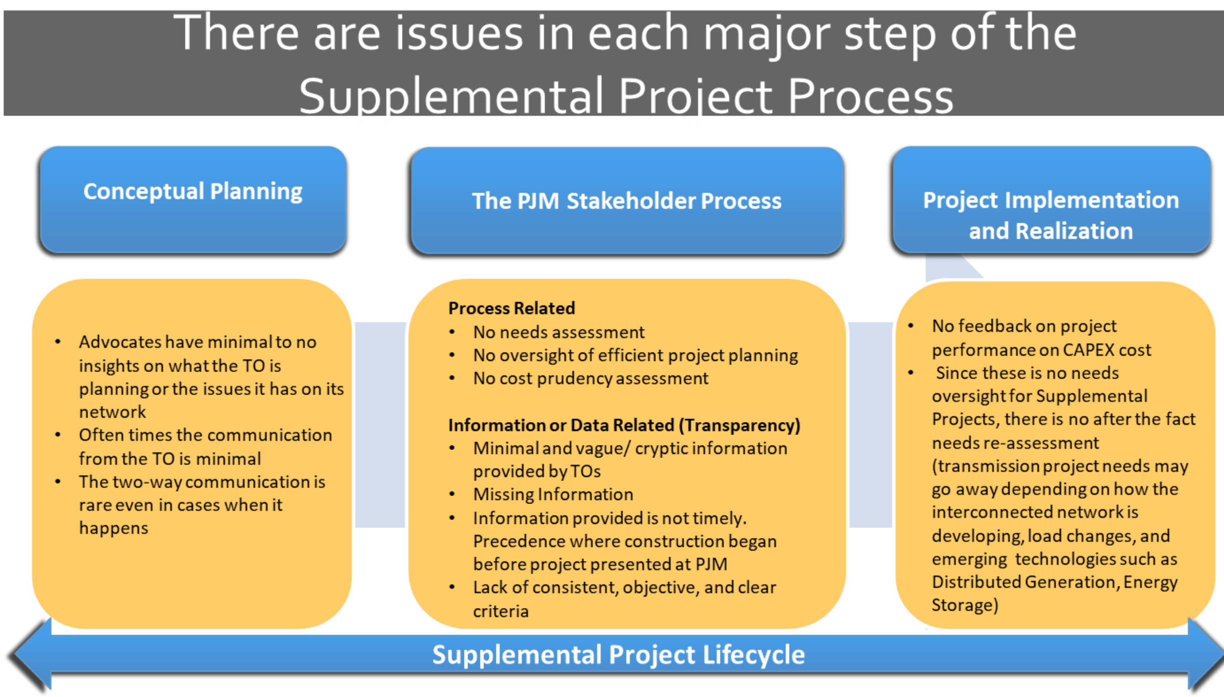


Figure 1: Issues with Supplemental Transmission Project Process

Though PJM has taken some steps to improve the stakeholder engagement for STPs, numerous issues remain with the overall assessment and oversight of STPs. These issues also apply to STPs which were implemented or constructed in 2018. These issues are:

Issues with the transmission project oversight process during Step1 - Conceptual Planning phase:

1. **Lack of insights into STP pipeline**

   Most State Commission staff and Consumer Advocates have little to no insights into the PJM STP pipeline. Though certain states such as Ohio and West Virginia commission staff will have meetings with TOs in their respective states from time-to-time, such meetings are not required by commission statutes and as a result, may not happen regularly and are not obligatory. Such meetings are also not happening uniformly across all PJM member states. In most cases the Commission staff and the Advocates are learning about the STP pipeline during the PJM stakeholder process. This results in lack of oversight into developing transmission needs. It also prevents oversight during initial stages of the transmission planning process for a STP, which is important to determine the scope of work and CAPEX budget of the developing pipeline of STPs.

2. **Minimal Communications during the Conceptual Planning Phase**

   State Commission staff and Consumer Advocates have, in most cases minimal feedback or insights from incumbent transmission utilities during the conceptual planning phase. Such communication should include a snapshot or summary of transmission issues developing in a utility's footprint and a high-level summary of potential transmission solution(s) that can address the identified STP needs.

   In some cases, there may be some communication happening between the sponsoring TO and the State Commission staff, but such communication is rare, irregular, and not procedurally required.

Issues with the transmission project oversight process during the PJM Stakeholder process and during assessment by State Commissions and State Consumer Advocates:

1. **No independent needs assessment**

   Currently there is no transmission needs assessment being performed for STPs by an independent authority such as PJM. Per the PJM tariff, PJM is not required to perform any needs assessment for STPs and PJM currently performs no need assessment for STPs. Similarly, if a STP needs no Certificate of Public Convenience and Necessity (CPCN), it is likely to have no regulatory oversight at the State Commission level. As a result, STPs needing no CPCN will have no need assessment performed to assess the need of the transmission project during its entire life cycle, from concept to completion. Therefore, a significant number of STPs reach the project construction or implementation phase without any independent needs assessment. The only project needs assessment that is being performed in such cases is performed by the Transmission Owner sponsoring the project.

2. **Limited assessment of transmission solution options**

A comprehensive transmission solution assessment and solution development should involve rigorous assessment and testing of transmission solutions that may address an identified transmission issue or need. Though some limited needs assessment is being performed by a sponsoring transmission owner, it is not fully clear (or transparent) that a comprehensive assessment of all possible solutions is being performed by the sponsoring transmission owner. Such an assessment is important to identify the most cost effective and cost efficient STP to an identified need for a STP. Though Continuum Associates did not perform a deep-dive review on how and to what extent sponsoring TOs are performing assessment of transmission solutions to a particular need, we did find instances where stakeholders such as AMP found lower cost alternatives to a specific transmission solution that the TO was proposing to pursue. We believe that this may be an indication that TOs may be performing only a limited assessment of transmission solution options to a particular transmission need. Additionally, there may be instances where a lower cost or more efficient solution may exist to a particular transmission need, but has not been pursued or evaluated by a transmission project sponsoring Transmission Owner. And as mentioned previously in this report, since PJM is not performing any independent needs assessment of STP, a comprehensive and thorough assessment of transmission solution options may be lacking for a number of STPs.

3. **No or minimal transmission project cost prudency assessment**

Transmission project cost prudency in the context of STPs involves ensuring that the least cost transmission project that addresses the transmission need is proposed and pursued for implementation. It is an iterative process requiring costing each transmission solution that can address specific needs that have been identified and a comprehensive cost-benefit analysis of each viable and effective solution. Ultimately, the iterative exercise should result in the lowest cost transmission solution that addresses a specific transmission needs. Since none of the STPs undergo a rigorous needs assessment or solution assessment at PJM, such cost prudency is not being done by PJM staff when the project is presented to PJM. If the STP needs no CPCN, no cost prudency is being done by the State Commission staff either. During our interviews with the State Commission and Consumer Advocates staff, lack of transmission project cost prudency was repeatedly highlighted as an issue. Transmission project cost prudency in this context also means that the CPAEX cost of a STP is accurately estimated, and neither overestimates or underestimates. State Commission and State Advocates repeatedly indicated lack of or absence of in-house expertise within their organizations that can perform thorough cost prudency assessment of transmission projects.

4. **Transparency related issues:**

There are a number of transparency related issues with the current PJM Stakeholder Process:

a. Minimal and vague information provided by project sponsors (incumbent TO proposing the project)

   This primarily involves limited information provided by a TO for a STP in many cases during the PJM stakeholder process. Even in cases where the information is provided, it may be vague preventing a stakeholder from fully understanding the issue that a TO is trying to resolve and the solution that is being proposed. We found that in many cases, the TOs are presenting very limited information during the PJM stakeholder process, thereby limiting comprehensive understanding of the needs that a proposed STP is addressing.

b. **Missing information**

   During our due diligence, we found instances where not all the pertinent information was being presented for a STP by the sponsoring TO. In many cases, only high-level information for a STP was being presented for both the transmission solution and the transmission need. Lack of all pertinent information from the sponsoring TO for a STP prevents thorough due-diligence of a STP during the PJM stakeholder process.

c. **Lack of up-to-date information and not following the Attachment M-3 process**

   There have been instances where the STP related information presented by a sponsoring TO, was either not up-to-date or did not follow the right order of pursuing a STP through the PJM stakeholder process, the Attachment M-3 process. There are known instances where a STP was presented by the sponsoring TO after engineering and design had begun on the STP or the STP was ready to proceed to implementation, indicating completion of engineering and design. This is not in line with the intent of PJM's Attachment M-3 process, according to which PJM Sub-regional RTEP Committees should have an opportunity to provide comments on assumptions, methods, system needs, and potential transmission solutions for a STP. Per the Attachment M-3 process, the PJM Sub-regional RTEP Committees should have a meaningful opportunity to participate and provide comments and feedback thorough the entire planning process for a STP[10].

d. Lack of consistent, objective, and clear planning criteria

As noted in Section 1 of this report and Appendix A of this report, a number of TOs do not provide clear, concise, and comprehensive planning criteria for their transmission projects. Transmission criteria provided by TOs and published on PJM's website varies from a single page to tens of pages. At this time, it also appears that PJM is not requiring its member TOs to provide a consistent set of planning criteria which can be used by stakeholders to evaluate a STP in a uniform manner.

5. No assessment of non-transmission alternatives (NTAs)

Based on our review of STPs presented at various PJM committees and forums, our understanding is that the TOs are currently performing no non-transmission alternatives solutions assessments for an identified need requiring a transmission solution. Certain type of needs for STPs such as those feeding non-networked loads at the end of long radial transmission lines, critical loads requiring second or third feed for high redundancy, and loads in densely populated urban areas where building transmission is difficult may be good candidates for NTAs. NTAs may be easier to implement, more cost effective, and lower in cost in such situations. However, such assessment is currently either not being performed at all or not being performed in earnest for serious consideration.

Issues with the transmission project oversight process during the STP Implementation Phase:

1. Little to no feedback on efficient implementation of a STP

Currently, TOs are not required to report their performance on the implementation of a STP, i.e. a TO is not required to report on its performance on implementation metrics such as cost and schedule. This prevents the Consumer Advocates or the PJM stakeholders from

[10] Attachment M-3: Additional Procedures for Planning of Supplemental Projects; PJM Open Access Transmission Tariff

knowing how well a STP is being implemented by a sponsoring TO. However, we note that this is a wider industry issue and is not limited to PJM STPs.

2. **No after-the-fact reassessment and assessment of non-transmission alternatives:**

There is no periodic re-assessment of need for a STP. Such a re-assessment would generally happen before a STP begins construction and may apply only to larger STPs with longer gestation periods. A final re-assessment may reinforce the need for a STP and also ensure that the proposed transmission solution continues to be the most appropriate solution, in case there is a change in the scope and need for a STP.

5.3 Issues and Challenges with Planning and Implementation of Supplemental Transmission Projects, Specifically Applicable to Consumer Advocates and State Commission Staff

To fully understand the issues of regulatory oversight for STPs, it is also important to understand some of the challenges that the State Commission staff and Consumer Advocates currently face with performing oversight for transmission projects. During the course of our assessment of current oversight mechanisms in place at State Commissions and Consumer Advocates for STPs, we identified a number of systemic and structural issues with the oversight required for STPs and their planning. These issues specifically impact the Consumer Advocates and the State Commission staff due to the nature of these issues and their interaction with the structure of the Consumer Advocates and State Commissions. These issues were identified during our discussions and interviews with the State Consumer Advocates and State Commission staff. Below is a summary of these additional issues:

1. **Technical challenges with thorough evaluation of transmission projects, including STPs**

   Transmission planning process is technically challenging and requires diverse skill sets, currently not in place at most State Commissions or Consumer Advocate offices. Similarly, project costing and estimating skills are also lacking within the State Commission and Consumer Advocate organizations.

2. **Resource Constraints**

Most State Commission staff and Consumer Advocates are resource constrained and lack sufficient staff strength to perform a full and thorough oversight and due-diligence of STPs that are being presented at PJM committees. In the past few years, as also shown in the data presented in Appendix B and C, the numbers of STPs have increased significantly further worsening the situation of resource constraints at various State Commissions and Consumer Advocates. In states where the number of STPs has increased significantly over the past few years such as Ohio, Virginia and New Jersey (amongst others), Consumer Advocates have not been able to keep up with oversight related workload.

3. Lack of Overt Regulatory Oversight

Some states such as New Jersey and Indiana require no CPCN for power transmission projects. Hence in such states, under certain circumstances, a STP may have no overt oversight project at all. Certain other states such as Michigan have a higher threshold for transmission projects at 345 kV and hence may have rather limited or no oversight for STPs, which in many cases tend to lower voltage at less than 345 kV.

6. Interviews with State Consumer Advocates Staff and State Utility Commission Staff

Continuum Associates reached out to Consumer Advocates for all 13 PJM member states and District of Columbia to understand any statute or regulations in place, which gives the Consumer Advocates an opportunity to participate in the regulatory oversight of Supplemental Transmission Projects proposed in PJM's footprint. At the suggestion of CAPS, Continuum Associates also reached out State Commission staff for the 13 PJM States and District of Columbia to identify and understand specific statutes in the public utilities laws in the respective states which gives the ability to the Commission staff to have regulatory oversight of Supplemental Transmission Projects.

Below is a summary of our findings from our outreach with the Commission State and Consumer Advocates staff:

Comments and Feedback on Oversight for STPs	Applicability
On statutory regulations governing Supplemental Transmission Project in PJM Footprint	
1. States do not have statutory regulations that apply specifically to Supplemental Transmission Projects. Transmission Projects are not differentiated or categorized based on the nature of need that they are trying to address. As a result, there is no differentiation between Baseline Reliability Transmission Project, Supplemental Transmission Project, or another category of transmission projects.	Applies to all states. No exceptions.
2. States depend on the Certificate of Public Convenience and Necessity (CPCN) process to regulate transmission projects, including Supplemental Transmission Project. Other than the CPCN process, there is no other statutory regulatory mechanism through which the States perform oversights of STPs, specifically the need for STPs.	Applies to all states. Exceptions are Indiana and New Jersey which do not have a CPCN requirement for transmission projects

Comments and Feedback on Oversight for STPs	Applicability
Oversight Process	
1. In general, both State Commission and Consumer Advocates make good effort to keep track of Supplemental Transmission Projects, where possible. The primary mechanism through which such an oversight is provided is the need for a CPCN in cases where a transmission project meets or exceeds thresholds for a CPCN. Transmission projects that do not need any CPCN may have no overt oversight. The only exception to this may be cases where the Commission is approached to provide zoning exemptions for transmission projects traversing multiple towns and counties within their states.	Applies to all states
2. State Commissions and Consumer Advocates depend on the PJM stakeholder process undertaken through various PJM committees and sub-committees as the initial oversight mechanism. The PJM stakeholder process also serves as the initial and in some cases the only mechanism through which Consumer Advocates and State Commissions learn about the STPs proposed in their respective states.	Applies to all states

6.1 Regulations Used by Different PJM States for Oversight of PJM Supplemental Transmission Projects

None of the PJM States use specific statutory regulations that apply only to PJM Supplemental Transmission Projects. No overt regulations exist within PJM States which may be specific to Supplemental Transmission Projects. State statutes make no differentiation of transmission projects based on the need or the issue that they address such as baseline reliability, supplemental, or network projects. State regulations generally apply to transmission project and the extent of regulatory reach is determined by the scope of the project including length (length of a transmission line in miles), voltage level (69 kV and above, 100 kV and above, etc.), the need for green field development (a new ROW or expansion of an existing ROW), and in some cases the extent of additional infrastructure (number of new transmission poles and so on).

The only regulations through which the PJM States have regulatory oversight of transmission projects, including Supplemental Transmission Projects is the Certificate of Public Convenience and Necessity (CPCN). The need for a CPCN is the only threshold through which PJM member states have regulatory oversight over a transmission project. Transmission projects which do not need a CPCN for any reason currently have no state-level regulatory oversight.

6.2 Policies and Methods Used for Oversight of PJM Supplemental Transmission Projects.

Most State Commissions and Consumer Advocates engage with PJM committees and sub-committees on as needed basis. In many cases, there is also some engagement with TOs, but that is limited and not regular. Below are our findings on how State Commissions and Consumer Advocates are currently undertaking oversight of PJM STPs.

1. State Commission and Consumer Advocates regularly call into PJM TEAC and sub-committee meetings such as Sub-regional RTEP Committee meetings to keep abreast of developments of transmission infrastructure in their states.
2. Commission staff depends on Organization of PJM States, Inc. (OPSI) and the consultant(s) hired by OPSI to keep them updated on transmission related issues at PJM, which may also include issues relates to STPs.
3. Certain states such as Kentucky and Ohio have close cooperation between the State Commission and the Consumer Advocates where both parties collaborate on issues related to transmission development and filings for transmission projects by the incumbent TO.
4. Our discussion with Kentucky and Illinois highlighted the active involvement of Consumer Advocates where they both educate and advise the Commission staff on issues related to transmission development and vice-versa. Consumer Advocates also have a precedence of intervening in CPCN proceedings from time to time.

Additionally, in talking with the State Commissions and Consumer Advocates, most of them highlighted limited resources within their organizations to perform thorough oversight of transmission projects. Except for a handful of State Commissions such as Ohio, most State Commission do not have adequate technical and engineering staff or resources that specialize in utility transmission planning and cost estimation of utility transmission infrastructure. In such cases, the Commission staff mostly depends on PJM's ability, as the regional transmission organization to provide such expertise which can be utilized during needs assessment of transmission projects. Such an arrangement and delegation of responsibility would generally work well in cases where PJM is providing a more thorough due-diligence. But in the case of Supplemental Transmission Projects where PJM is not performing any needs assessment or due diligence of the underlying needs of a transmission project, there is a strong possibility of no need assessment or due diligence ever being performed. This is especially true of a Supplemental Transmission Projects that fall under the threshold of a CPCN in a respective state.

7. Improving Oversight of PJM Supplemental Projects

7.1 Methods to Improve Oversight of Supplemental Transmission Projects

In this section we identify specific methods and steps that need to be incorporated to enhance and improve oversight of STPs. These methods are specific to the State Consumer Advocates and the State Commission staff. Our overall approach to implementing methods and steps to improve oversight is two-pronged:

1. Short-term improvements that can be implemented immediately to provide prompt oversight improvements

2. Medium-term to long-term improvements that are more profound and should be or can be implemented only over a longer period or systemic improvement which are required to make the oversight process more sustainable. Medium-term to long-term improvements are also required to meet the overall long-term objectives of the State Commission staff and Consumer Advocates

A. Short-Term Improvements

Figure 3 below provides a summary of short-term improvements that should be made to each of the three main steps of the STP life cycle to enhance oversight. Detailed descriptions of our recommended improvements are provided following Figure 3.

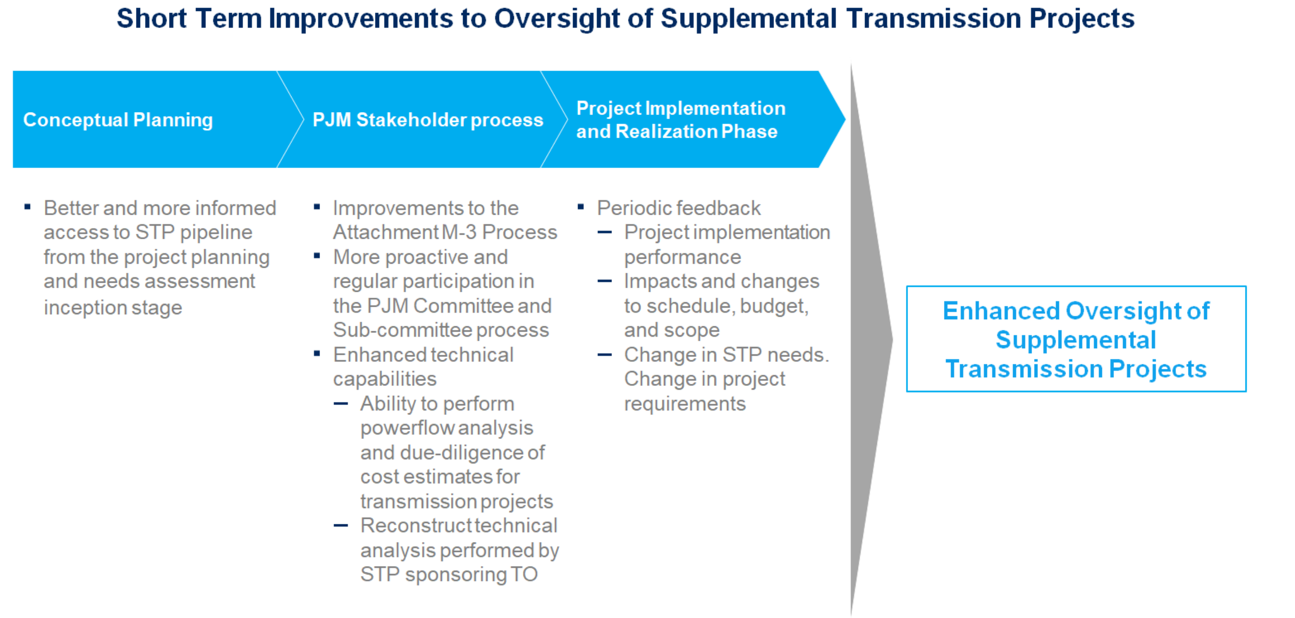


Figure 2: Short-term improvements to enhance oversight of Supplemental Transmission Projects

1. Periodic and on-going access to STPs from the conceptual stage

The Consumer Advocates and the State Commission staff need to have better, on-going access, and more periodic interaction with their TOs to learn about the Supplemental Transmission projects as soon as they are planned or conceived. This will avoid the information asymmetry that the Consumer Advocates and the State Commission staff currently have. Under the currently unstructured process, most Consumer Advocates and State Commission staff either learn about a STP when it has been presented during various PJM stakeholders at the PJM Stakeholder process or when the sponsoring TO approaches the State Commission for regulatory approval for a CPCN. There are few instances where the State Commission staff will learn about a proposed transmission project early on in the planning process, but such instances are rare and do not happen consistently across all states or for all STPs.

Some of the resources that the State Commission staff and the Consumer Advocates can use to proactively learn about STPs, early in the planning process include:

- Integrated Resource Plan (IRP), which a sponsoring TO may publish from time-to-time.[11]

[11] Not all TOs do or are required to publish their IRPs. Some of the states where IRPs are filed regularly include West Virginia and Kentucky.

- Annual Transmission Plans – These may include insights on a utility's transmission development plans over a five, ten, or a longer period of time.

- Rolling Transmission Plans on Planned and Proposed Projects – These may provide details on transmission needs and possible transmission solutions.

- Periodic Meetings with presentations – to discuss transmission needs, solutions, and cost of various solutions.

2. Improvements to the PJM Stakeholder Process

The PJM stakeholder process for STPs has made some improvements pertaining to compliance of the overall stakeholder process with the PJM OATT, however there are still number of shortcomings in the overall due-diligence of STPs. The Attachment M-3 process is good in intent in its current form and PJM is undertaking efforts to ensure that the PJM stakeholder process follows the Attachment M-3 process. However, our assessment is that the Attachment M-3 process is currently not being followed in spirit and more efforts are required from PJM to enforce compliance with Attachment M-3 process. Some of this effort by PJM is currently underway.

The other issue with PJM stakeholder process from the Consumer Advocates and State Commission staff perspective is irregular and inadequate participation in the stakeholder process. Though some of the Consumer Advocates and State Commission staff regularly participate in the PJM committee and sub-committee process, many are not able to. This can be attributed to lack of internal resources to undertake adequate and regular committee and sub-committee participation and in some cases lack of access to technical skills or staff to comprehensively participate in the PJM stakeholder process. Our recommendations to improve the PJM stakeholder participation process by Consumer Advocates and State Commission staff include:

- Proactive participation in the SRTEP, RTEP, and other PJM Committee Processes, with a sharp focus on assessment of STP needs and STP solutions being proposed.

- The Consumer Advocates and State Commission staff will need to enhance their technical capabilities significantly to productively participate in the three-step Attachment M-3 Process at the various PJM committees.

3. Mitigating Resource constraints and enhancing technical due-diligence capabilities

In terms of enhancing or developing technical capabilities, we recommend this effort be undertaken in a centralized manner by CAPS rather than by individual Consumer Advocates. The following skill sets should be developed as part of this short-term improvement recommendation:

- Full Transmission Planning needs evaluation and assessment capabilities. This capability has to be fairly comprehensive to the extent where CAPS or a consultant supporting CAPS can fully interpret the technical analysis that the TOs are presenting and recreate the powerflow results if the need be

- Develop cost estimation capabilities to develop high-level cost estimates (+/- 30%) for TO proposed transmission upgrades

Developing these skills in-house at CAPS through hiring full-time staff may be expensive and inefficient. Initial work load may not be consistent and sufficient to justify hiring full-time technical staff. A more efficient approach may be to engage a qualified consultant to transmission planning and transmission cost estimation capability and transition to full-time employees as and when the workload justifies it.

4. Improvement to the oversights during the project implementation phase

Currently, there is no mandatory feedback required to be provided to Consumer Advocates, State Commission staff, or to PJM once a STP has progressed beyond the stakeholder committee process and into the implementation phase. The transmission planning function is very dynamic in nature. Additionally, the dynamics of the electric power grid in terms of transmission needs and transmission projects being proposed change frequently. Considering such a scenario, we recommend a feedback loop to Consumer Advocates and the State Commission staff on a periodic basis, once a STP has progressed to implementation phase. Such information based feedback loop will provide updates to Consumer Advocates and State Commission staff on any changes in the needs for the STPs and any changes to the scope and budget of the STPs due to change in needs for the STPs.

B. Medium-Term Improvements and Long-Term Improvements

Medium-Term and Long-Term improvements primarily involve structural and systemic changes that need to be made to the overall STP oversight process from conceptual planning to implementation process. These structural and systemic changes would help achieve many of the objectives of transparency, more stringent oversight, and efficient transmission system planning in line with the objectives of the State Commissions and Consumer Advocates.

Below are recommendations to implement structural and systemic changes to the overall STP oversight process. These recommendations are targeted at PJM, State Commissions, and the Consumer Advocates:

1. Thinking outside the "Transmission Box"

Building additional transmission to address transmission system need is, in most cases the most cost effective solution. But this may not be true in all situations. Over the past few years, new and emerging technologies such battery storage, distributed generation, micro or mini grid, active and passive demand side management, collectively known as Distributed Energy Resources (DERs) have shown to provide a lower cost and equally reliable solution as a transmission solutions in some cases. This may be particularly true in cases where incremental power capacity is not significant or the transmission upgrade is required to serve a limited number of customers such as at the end of a radial transmission line or an isolated load pocket. In industry parlance, evaluation of DERs as an alternative to transmission solution is known as Non-wires Alternatives (NWA)

Some of the State Regulators such as the Massachusetts Department of Public Utilities (MADPU) require utilities to evaluate NWAs to a competing transmission need to ensure that the most cost-effective and efficient solution per the ratepayer's needs is selected. We recommend that evaluation of NWA be incorporated into the needs assessments that State Commission staff undertake for a STP.

2. Enhancing oversight for STPs through change in regulations [will require legislative interventions and changes]

During the course of our work for the CAPS, it was amply clear that some of the States lack overt oversight for STPs. New Jersey and Indiana are prime examples of this. Both New Jersey and

Indiana do not require CPCN for electric transmission project. In West Virginia, A CPCN is not required for extension of transmission projects that are classified as “extension during normal course”. Other states such as Michigan do not require CPCN for transmission voltages less than 345 kV. Most STPs, due to the type of transmission needs that they mitigate are likely to be less than 345 kV and hence may not need CPCN in states with higher CPCN voltage thresholds. We recommend that States undertake a thorough assessment of their CPCN requirements and thresholds, and make suitable change to state regulatory statutes to enhance overt oversight of transmission projects.

Appendix A

Comparative Assessment of Planning Criteria and Guidelines Used by PJM Transmission Owners for Transmission Projects

Transmission Owner (TO)	Date Published or Last Updated	Classification Based on Voltage Level	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
Atlantic Electric (AE)	March 31, 2016 AE updated its criteria to be consistent with other Exelon subsidiaries in May 2019	Yes, planning criteria applicable to only 69 kV and above	Not called out explicitly, but needs to be followed per NERC reliability standards	Mid-Atlantic Area Council (MAAC), NERC TPL Standards, ReliabilityFirst Corporation Standards, PJM Reliability Criteria per PJM's Manual 14-B	Yes. Atlantic City Electric also has its own internal planning criteria which will meet or exceed primary planning criteria. Voltage criteria that AE follows is stricter than PJM's reliability criteria	Yes, voltage criteria	A stricter voltage criteria will most likely lead to higher cost of transmission solutions	Details provide by AE on its planning criteria are fairly minimal. This assessment is based on the criteria published in 2016.
American Electric Power (AEP)	April 26, 2017	Yes	Yes, 765 kV, 345 kV, 161 kV, and 138 kV are considered BES. Lower voltages are non-BES (consistent	NERC TPL Standards, ReliabilityFirst Corporation Standards PJM Reliability Criteria not explicitly mentioned	Yes. P7 category event is tested as a three phase fault. NERC criteria requires P7 to be tested only as a single phase to ground fault	None indicated in its planning criteria document -NA-	Analysis of a P7 category event as a three phase fault is likely to increase cost of a transmission project involving power	AEP's planning criteria primarily depends primarily on NERC reliability criteria and PJM's Reliability

Transmission Owner (TO)	Date Published or Last Updated	Classification Based on Voltage Level	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
			with NERC definition)				stability issues	Criteria per Manual 14-B
PPL Electric Utilities Corporation (PPL)	Revision 6, June 1, 2011. Additional revisions on August 27, 2018	Yes, based on BES and non-BES voltage standards	Yes	NERC TPL Standards and PJM Reliability Criteria per PJM's Manual 14-B	None indicated in the planning criteria published by PPL	None indicated in its planning criteria document	-NA-	PPL's planning criteria primarily depends primarily on NERC reliability criteria and PJM's Reliability Criteria per Manual 14-B

Transmission Owner (TO)	Date Published or Last Updated	Classification Based on Voltage Level	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
Baltimore Gas and Electric Co. (BGE)	February 29, 2016	Yes	Yes	NERC, ReliabilityFirst, PJM Reliability Criteria, and BGE's internal criteria	BGE has its own internal criteria or standard. However, BGE claims that its internal criteria is consistent with ReliabilityFirst Regional Reliability Council Standards and NERC Planning Standards	BGE standard EPB-13006 is explicitly mentioned, which appears to apply only to relay and communication devices used for protection and control of power transmission infrastructure	BGE's internal criteria is not likely to have significant impact on supplemental transmission project costs Details on BGE standard EPB-13006 are not available publicly	BGE. This assessment is based on the criteria published in 2016.
Commonwealth Edison (ComEd)	December 5, 2015 Exelon updated its	Yes	Yes	NERC, ReliabilityFirst, PJM Reliability Criteria	Yes, based on certain substation and critical power	ComEd has its own transmission planning security and	Higher cost of transmission projects in certain niche	Impact of ComEd's own transmission planning security and

Transmission Owner (TO)	Date Published or Last Updated	Classification Based on Voltage Level	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
	criteria to be consistent for all its subsidiaries in May 2019				generation facilities such as nuclear power plants	adequacy criteria which it claims to be governed by NERC TPL standards	cases. Such cases may be limited in number.	adequacy criteria on supplemental projects may be limited
Dayton Power and Light (DP&L)	May 19, 2015	Yes, DP&L has 69 kV, 138 kV, and 345 kV transmission assets	Yes, 69 kV is non-BES. 138 kV and 345 kV is BES (consistent with NERC standards)	NERC Reliability Standards applicable to 345 kV and 138 kV. 69 kV is planned using PJM reliability criteria and DP&L's design guideline	None indicated in its planning criteria document	-NA-	-NA-	DP&L's planning criteria provides minimal detail and primarily refers to NERC Reliability Standards

Transmission Owner (TO)	Date Published or Last Updated	Classification Based on Voltage Level	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
Delmarva (same as AE)	March 30, 2016 Exelon updated its criteria to be consistent for all its subsidiaries in May 2019.	Yes, planning criteria applicable to only 69 kV and above	Not called out explicitly, but needs to be followed per NERC Reliability Standards	Mid-Atlantic Area Council (MAAC), NERC TPL Standards, ReliabilityFirst Corporation Standards, PJM reliability criteria per PJM's Manual 14-B	Yes. Delmarva also has its own internal planning criteria which will meet or exceed primary planning criteria. Voltage criteria that Delmarva follows is stricter than PJM's Reliability Criteria	Yes, voltage criteria	A stricter voltage criteria will most likely lead to higher cost of transmission solutions	Details provide by Delmarva on its planning criteria are fairly minimal, similar to what was observed for AE's planning standards
Dominion	March 15, 2019	Yes	Yes	NERC Reliability Standards, PJM reliability criteria per PJM's Manual 14-B	Yes	Dominion has its own "Dominion Energy Criteria" which is more stringent for	Higher cost of developing transmission at 500 kV. Cost impact of "Dominion Energy Criteria" on supplemental	Dominion provides a very detailed planning criteria

Transmission Owner (TO)	Date Published or Last Updated	Classification Based on Voltage Level	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
						500 kV transmission	projects may be minimal	
Duquesne Light Company (DLC)	March 1, 2017	Yes	Yes	NERC TPL Standards, ReliabilityFirst Corporation Standards, PJM reliability criteria	Yes, DLC follows load and area specific internal planning criteria which is more stringent compared to NERC Reliability Criteria	Local criteria, specifically to the City of Pittsburgh, and surrounding tristate area. No loss of load following N-2 event	DLC's specific and more stringent internal planning criteria likely leads to higher cost for transmission solution proposed in City of Pittsburgh, and surrounding tristate area	Details provided by DLC on its more stringent internal planning criteria are minimal.

Transmission Owner (TO)	Date Published or Last Updated	Classification Based on Voltage Level	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
Duke	October 17, 2011	No explicit voltage level classification is mentioned	No explicit classification is mentioned, but most likely applies (NERC requirement)	NERC TPL Standards and ReliabilityFirst Corporation Standards Duke applies its own planning criteria as well	Yes	Yes, location specific and asset specific	Duke's internal criteria should have minimal impact on incremental cost of a transmission project	In general, Duke provides minimal details on its planning criteria
Eastern Kentucky Power Co-operative (EKPC)	March 1, 2016	No explicit voltage level classification is mentioned	No explicit classification is mentioned, but most likely applies (NERC requirement)	North American Electric Reliability Council (NERC) Southeastern Reliability Coordinator (SERC) PJM Manual 14B Planning Criteria	Yes	Yes, specific to forced outages of power plants and transmission lines	EKPC's local criteria sis expected to have minimal impact on cost of developing transmission in most cases. Generation related local criteria may have a bigger impact on cost of	

Transmission Owner (TO)	Date Published or Last Updated	Classification Based on Voltage Level	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
							transmission development that serve generation	
FirstEnergy	December 18, 2014	Yes, classification based on 100 kV and higher, and less than 100 kV (but not less than 23 kV)	Yes	NERC TPL Standards, ReliabilityFirst Corporation Standards, and PJM Reliability Standards	Yes	Yes, "Transmission Planning Criteria" developed and applies to assets less than 100 kV. Additional guidelines also apply	Could not be determined since FE provides no details on its internal "Transmission Planning Criteria"	-NA-

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
Neptune Regional Transmission System, LLC (Operates an interconnector between PJM and NYISO)	April 6, 2009	None explicitly mentioned	No explicit classification, but expected to apply in line with NERC requirements	NERC TPL Standards and ReliabilityFirst Corporation Standards No further details are provided	None mentioned	None	Cannot be determined	The standard is mentioned in three lines. No meaningful comparison to criteria used by other TOs is possible for lack of details
Old Dominion Electric Cooperative (ODEC)	December 5, 2018	Yes, more stringent internal planning criteria for 69 kV transmission system	No explicit classification, but expected to apply in line with NERC requirements	North American Electric Reliability Corporation (NERC), ReliabilityFirst Corporation (RF), SERC Reliability Corporation (SERC), and the	Yes, ODEC follows a more restrictive and stringent criteria for 69 kV system	Yes, applicable to 69 kV network. Local criteria apply to both radial lines as well as networked transmission	ODEC restrictive local criteria applies to its 69 kV network Restrictions mostly apply to radial 69 kV transmission lines and to the extent	Such restrictions are likely to lead to increased costs for upgrades to or addition of new 69 kV

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
				PJM Interconnection, LLC (PJM)		lines at 69 kV. Limitation on generation dispatch	generation can be re-dispatched to alleviate overloads on the network.	lines

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
ITC Holdings	August 27, 2018	Yes, separate criteria for 100 kV and above. Criteria for below 100 kV is not provided	No explicit classification is mentioned, but most likely applies (NERC	NERC TPL Standards and SPP Planning Criteria	Yes. ITC planning criteria does provide more restrictions on NERC	None specifically mentioned. ITC mentions an End of Life as a planning	ITC's provides more restrictive planning criteria above and beyond the NERC TPL standards.	In our assessment, ITC's restrictive planning requirements above and

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
		or published on PJM website	requirement) Voltage classification appears to apply, after accounting for NERC BES voltage classifications		planning requirements	criteria that it considers as part of its planning process but provides no objective details around its applicability	These restrictions are expected to impact a small set of transmission projects, especially those required to mitigate more severe reliability concerns and issues on the ITC transmission network	beyond NERC standards will likely lead to higher cost of transmission projects in selected few cases. Such an impact, however, may be limited.
NAEA Rock Springs, LLC	April 6, 2009	None explicitly mentioned	No explicit classification	NERC TPL Standards and ReliabilityFirst Corporation Standards	None mentioned	None	Cannot be determined	The standard is mentioned is minimal in detail. Comparison to criteria

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
				No further details are provided				used by other TOs is not possible for lack of details

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
Ohio Valley Electric Corporation (OVEC)	October 18, 2018	None explicitly mentioned	Yes, OVEC follows NERC BES classification	NERC TPL Standards and ReliabilityFirst Corporation Standards OVEC depends on American Electric Power Service	"External Documents" are referred to in OVEC's planning standard, but no further details are	None explicitly mentioned	OVEC's transmission network was developed using a much more stringent criteria, but it appears a more stringent criteria is no	OVEC's system was designed to a more stringent standard in 1950s since it was developed to

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
				Corporation (AEPSC) East Transmission Planning group to conduct planning related assessments on its behalf	provided.		longer followed. As a result, cost impact on new transmission development including supplemental projects should be minimal.	supply the critical load of DOE's uranium enrichment facility in Portsmouth, Ohio
Orange and Rockland (O&R)	July 12, 2018 A previous version dated June 7, 2017 was reused in 2018.	Yes. Classification based on 100 kV and above.	Yes.	NERC TPL Standards, ReliabilityFirst Corporation Standards, PJM Reliability Criteria	None mentioned explicitly	None mentioned explicitly.	-NA-	-NA-

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
PECO	January 1, 2016	Yes, classification based on 100 kV and higher, and less than 100 kV	Yes, in line with NERC definition of BES and non-BES	North American Electric Reliability Corporation (NERC), ReliabilityFirst (RF) and the PJM interconnection.	Yes, PECO follows a stringent set of planning standards that apply to its transmission network, above and beyond NERC standards.	None mentioned, except a more stringent planning criteria that PECO applies across the board with no restrictions.	PECO's more stringent planning standards are invariably going to lead to a higher cost for transmission projects. Since PECO applies its more stringent planning criteria across the board with no exceptions, PECO's supplemental projects are expected to cost substantially more compared to a similar project in	

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
							another PJM TO's footprint	

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
Southern Maryland Electric Cooperative, Inc. (SMECO)	September 27, 2018	Yes, 100 kV and above vs. lower than 100 kV. Primary voltage levels are 230 kV, 69 kV, and 12.47 kV	Yes	NERC TPL Standards and ReliabilityFirst Corporation Standards and the PJM Interconnection, LLC (PJM) Reliability	None mentioned	No local criteria explicitly mentioned. But SMECO uses a narrower range for planning its lower voltage	Using a narrower voltage range for lower voltage network is likely to require a more robust network (lines and substations), especially at 15 kV and lower	Lower voltage steady state planning criteria will likely increasing costs for 15 kV and lower voltage network lines

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
		(SMECO)		Standards		(<=15 kV) network	voltages to meet reliability criteria	and substations
Rochelle Municipal Utilities	March 21, 2017	Yes	Yes	North American Electric Reliability Corporation (NERC) Standards, ReliabilityFirst Corporation Standards, and ComEd Transmission Planning Criteria PJM Planning criteria for transmission projects included in PJM RTEP	None mentioned	None mentioned	Cannot be determined, since no local criteria is mentioned	-NA-

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
Southern Maryland Electric Cooperative, Inc. (SMECO)	September 27, 2018	Yes, 100 kV and above vs. lower than 100 kV. Primary voltage levels are 230 kV, 69 kV, and 12.47 kV (SMECO)	Yes	NERC TPL Standards and ReliabilityFirst Corporation Standards and the PJM Interconnection, LLC (PJM) Reliability Standards	None mentioned	No local criteria explicitly mentioned. But SMECO uses a narrower range for planning its lower voltage (<=15 kV) network	Using a narrower voltage range for lower voltage network is likely to require a more robust network (lines and substations), especially at 15 kV and lower voltages to meet reliability criteria	Lower voltage steady state planning criteria will likely increasing costs for 15 kV and lower voltage network lines and substations
Rochelle Municipal Utilities	March 21, 2017	Yes	Yes	North American Electric Reliability Corporation (NERC) Standards, ReliabilityFirst Corporation Standards, and ComEd Transmission	None mentioned	None mentioned	Cannot be determined, since no local criteria is mentioned	-NA-

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
				Planning Criteria PJM Planning criteria for transmission projects included in PJM RTEP				

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
UGI, Inc.	April 3, 2009	None mentioned	None mentioned. But most likely followed per NERC	None mentioned	-NA-	-NA-	Cannot be determined since no local criteria mentioned.	-NA-

Transmission Owner (TO)	Date Published or Last Updated	Voltage Level Classification	BES vs. Non-BES	Primary Planning Criteria	Exceptions to the Primary Planning Criteria	Any Local Criteria	Impact of Local Criteria	Additional Notes and Observations
			requirements					

Appendix B

PJM Supplemental Transmission Projects: Proposed and Under Construction

PJM Transmission Supplemental Projects – Proposed and Under Construction

January 25, 2019 [Revised March 18, 2019]

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Source of information on supplemental projects

Sources (publicly available):

1. PJM Website (https://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx)
2. Other publicly available sources such as meeting material published on PJM committee meeting portals
3. Material published on PJM's regional subcommittee meeting portals
4. PJM TEAC presentations – January 10, 2019 and February 7, 2019

Data Processing:

1. Data on PJM's website is incomplete and generally of poor quality
2. Most updates are in the form of appending the database, rather than refreshing and updating
3. CA performed extensive data scrubbing and filled in the data where it was missing, to the extent possible

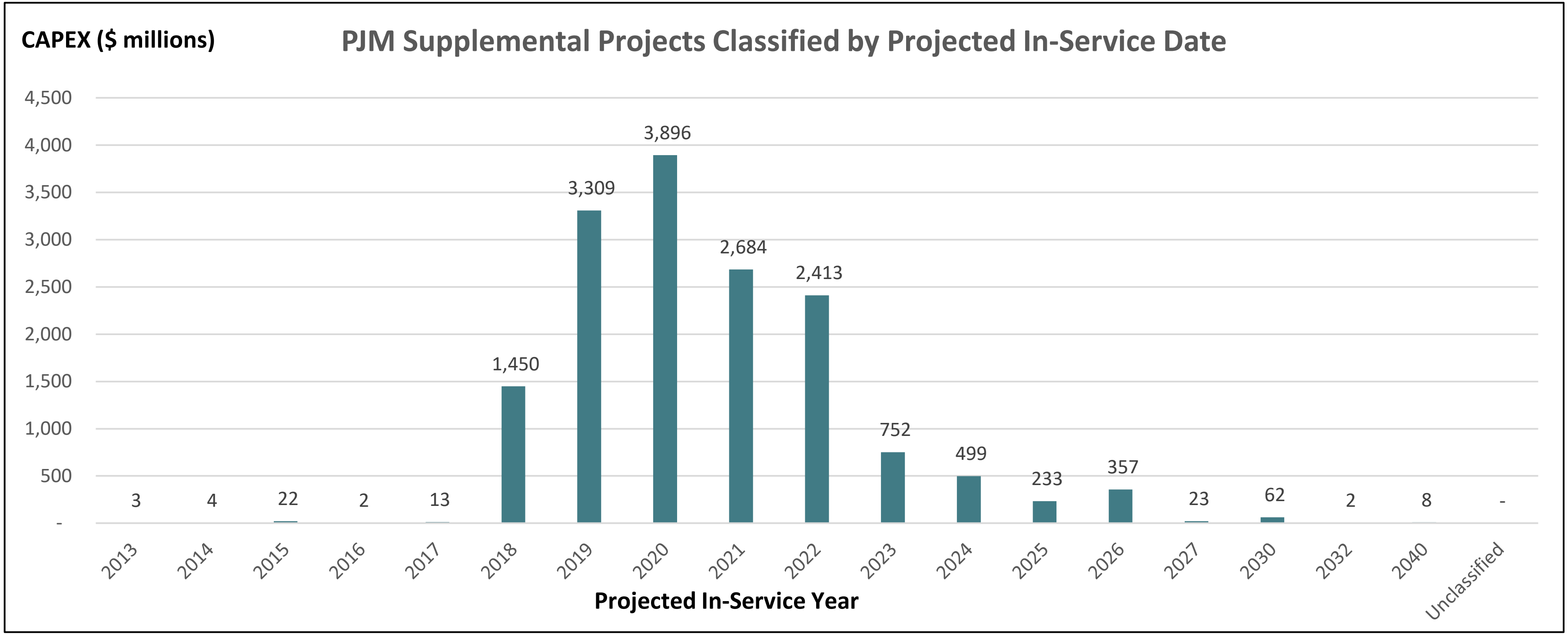
Findings – Supplemental Projects Proposed

- Total of 1,094 transmission projects are proposed across all categories. The in-service dates for STPs extend into 2040. In-service dates that are more than five years out are not likely to be accurate.
- Total capital cost of 937 projects proposed is $15.7 billion with proposed in-service dates extending up to 2040. Total CAPEX of all projects proposed is probably close to about ~ $18.5B - $20B
- Average cost of a supplemental project proposed is about $16.8M across all STPs proposed
- Variety of projects proposed based on capital cost:
  - Largest or most expensive project is a Transmission Hardening Program totaling $1,275B proposed by PSE&G. Expected to be complete by April 30, 2020
  - There are supplemental projects as low as $100,000 that are proposed by TOs
- Almost 157 proposed projects have no cost allocated to them
- Almost $2.63B in transmission projects have no cost allocated to them, and hence is not in total CAPEX for all projects. Actual cost may be much higher.

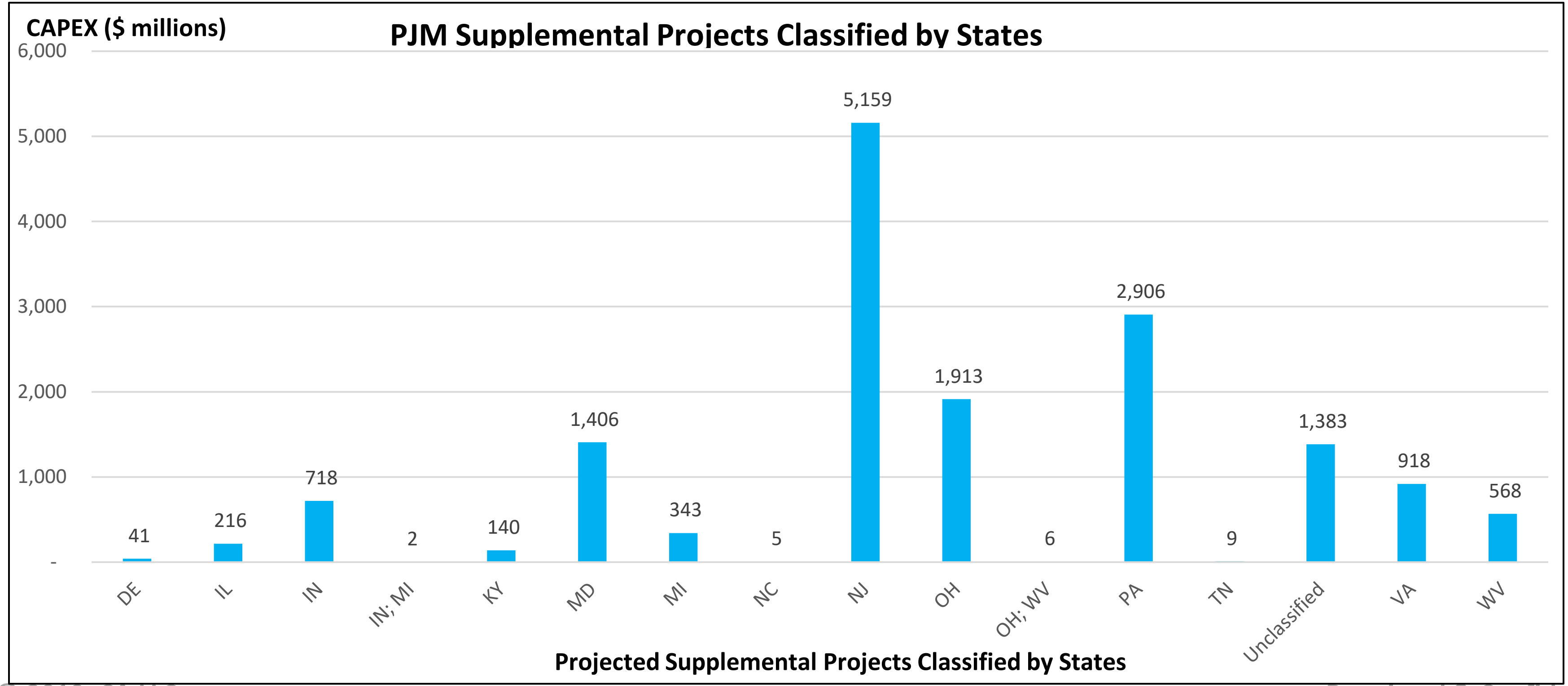
Findings – Supplemental Projects Under Construction

- Total of 542 supplemental projects are currently under construction. They are proposed to be completed by 2025.
- Total capital cost of 542 projects under construction is approximately $8.8B
- Average cost of a supplemental project under construction is $17.54M
- Actual CAPEX spend is most likely higher since almost 42 supplemental projects have no cost allocated
- We estimated that actual cost of supplemental projects under construction is approximately around $9.51B

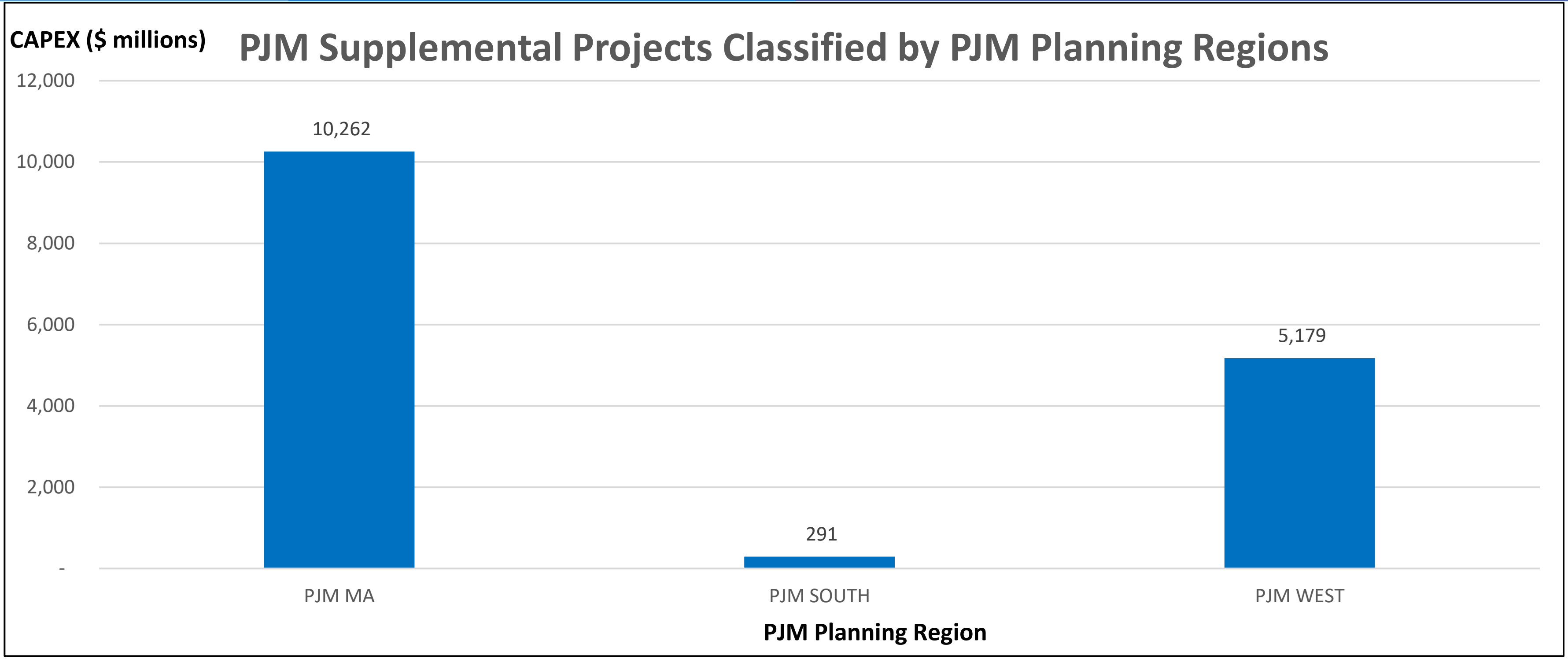
Analysis of proposed supplemental project – by proposed in-service date



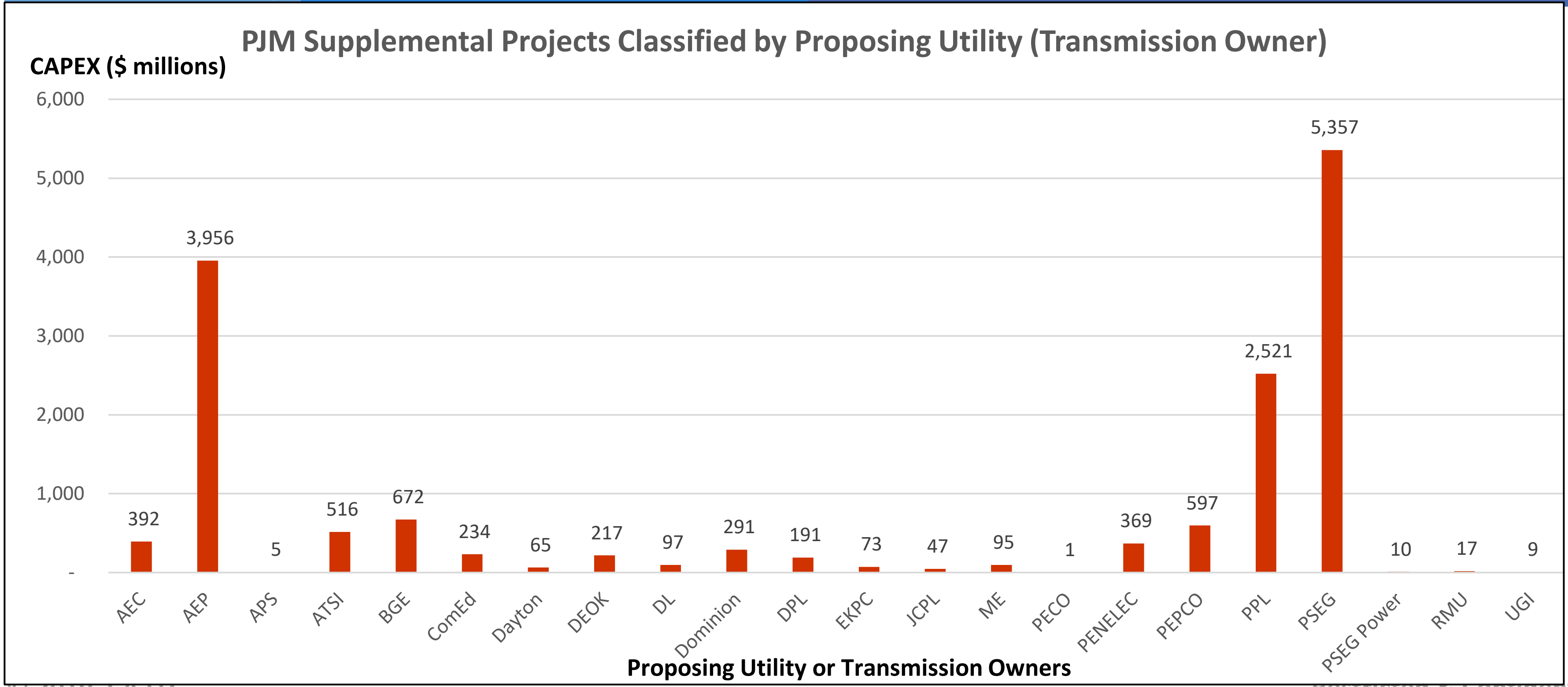
Analysis of proposed supplemental project – by State



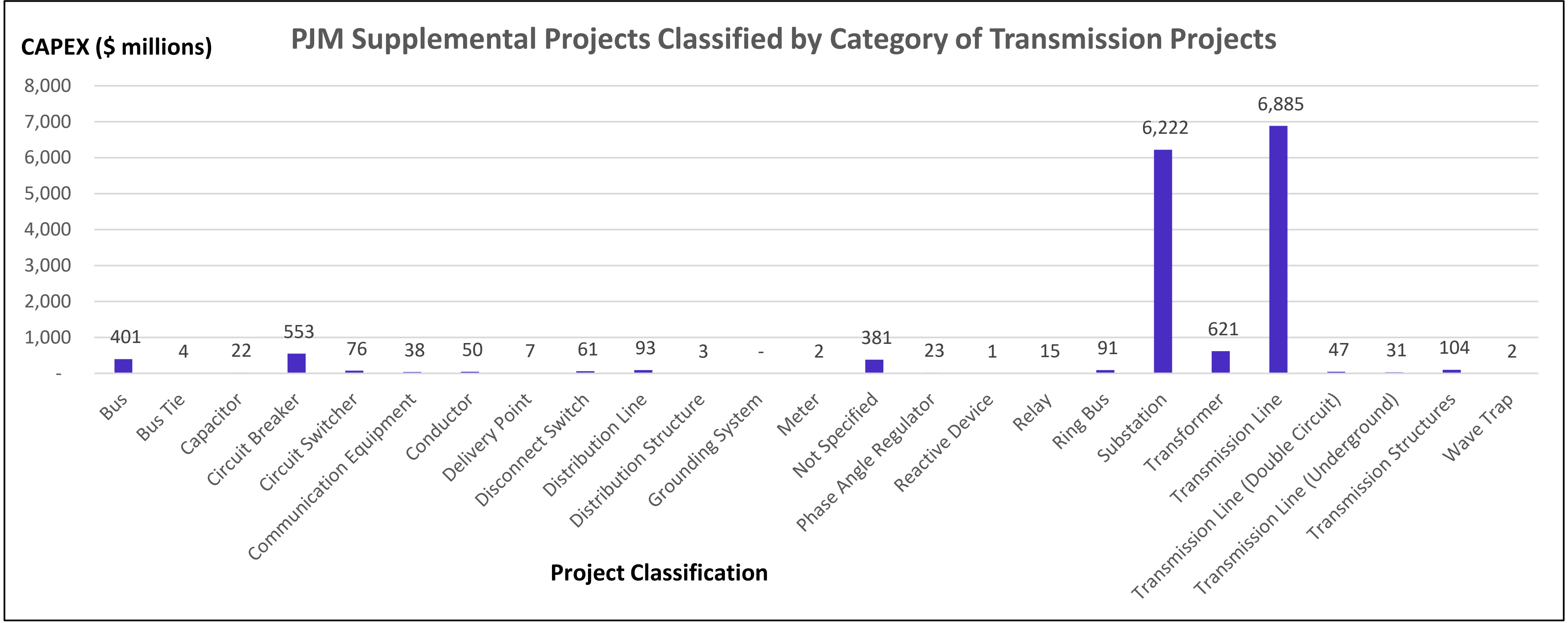
Analysis of proposed supplemental project – by PJM's planning region



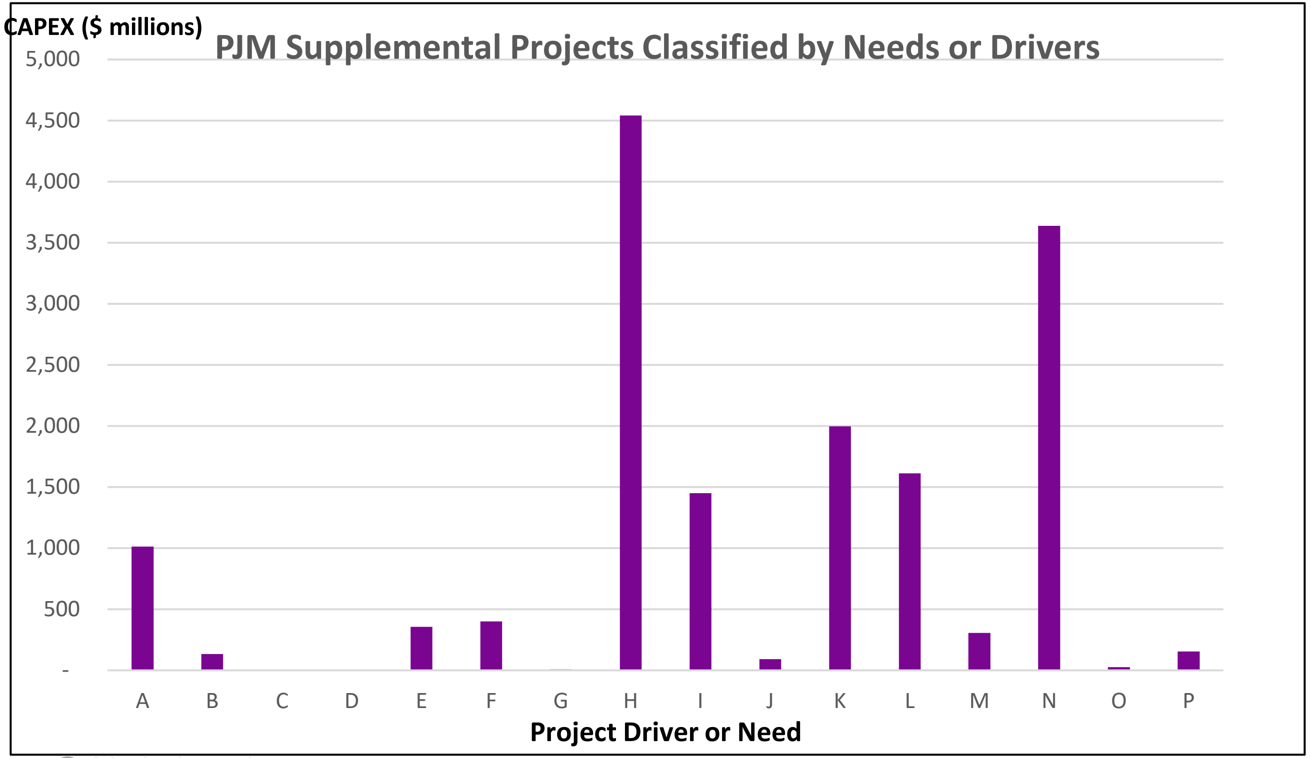
Analysis of proposed supplemental project – by the proposing TO or utility



Analysis of proposed supplemental project – by category of projects

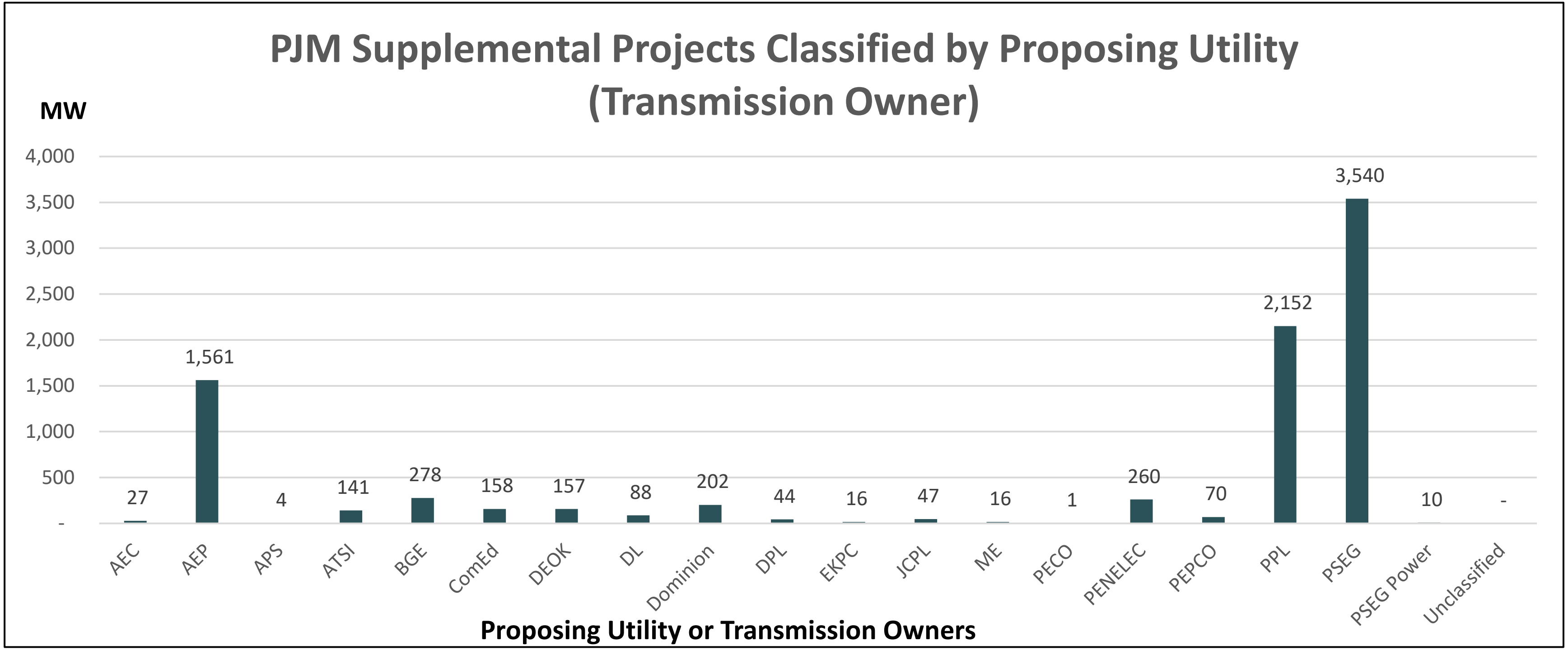


Analysis of proposed supplemental project – by needs or drivers

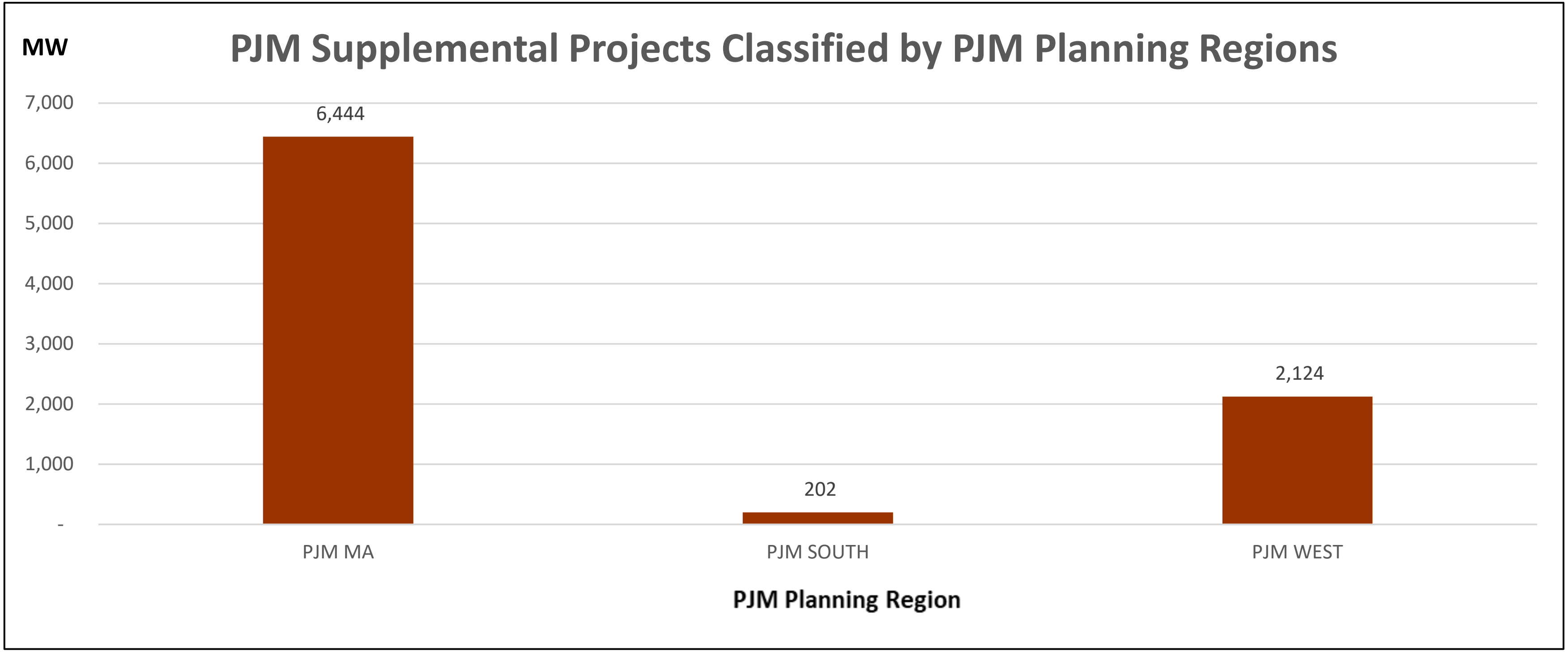


Driver Category	Driver Details
A	Customer Service
B	Customer Service / Equipment Material Condition,
C	Customer Service / Equipment Material Condition, Performance and Risk / Infrastructure Resilience
D	Customer Service / Equipment Material Condition, Performance and Risk / Infrastructure Resilience /
E	Customer Service / Equipment Material Condition, Performance and Risk / Operational Flexibility and
F	Customer Service / Operational Flexibility and
G	Customer Service / Operational Flexibility and Efficiency / Equipment Material Condition, Performance
H	Equipment Material Condition, Performance and Risk
I	Equipment Material Condition, Performance and Risk /
J	Equipment Material Condition, Performance and Risk / Infrastructure Resilience / Operational Flexibility and
K	Equipment Material Condition, Performance and Risk /
L	Infrastructure Resilience
M	Infrastructure Resilience / Operational Flexibility and
N	Operational Flexibility and Efficiency
O	Other
P	Unknown

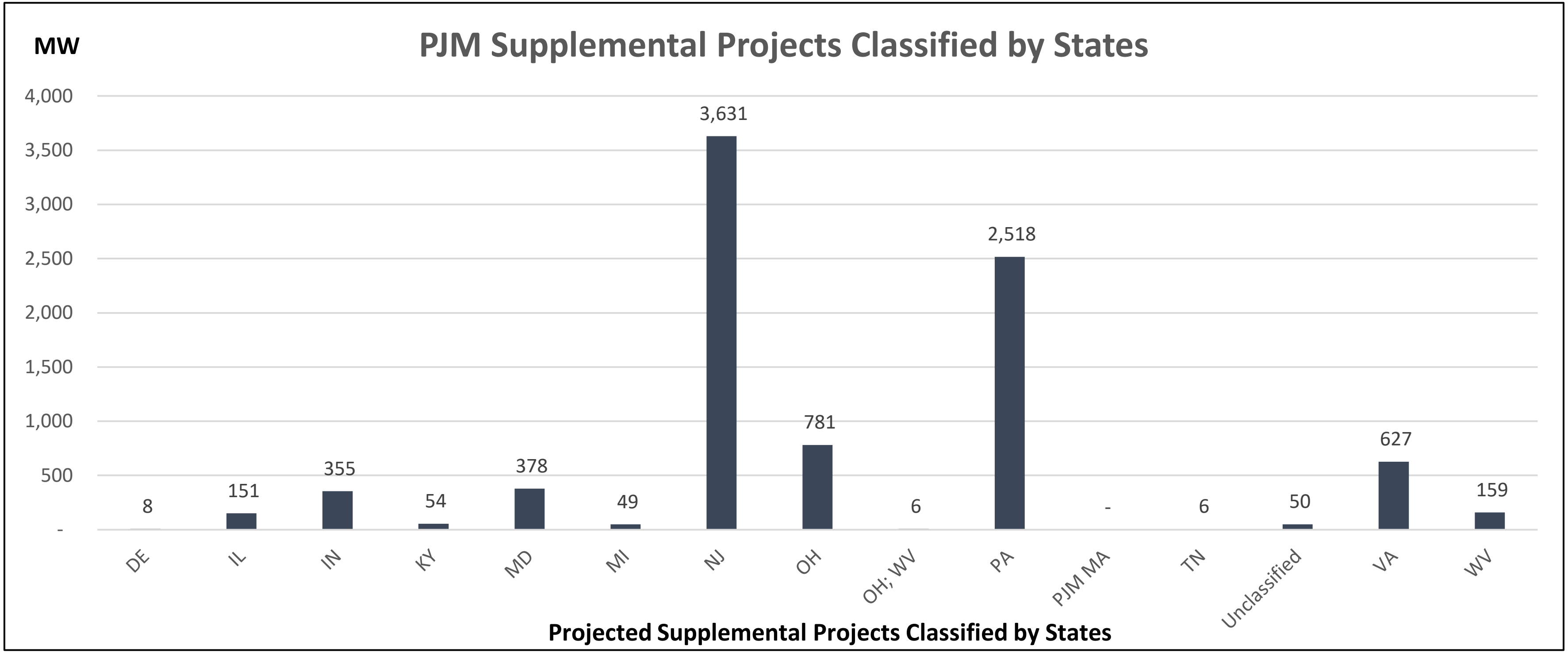
Analysis of supplemental project under construction – by the proposing TO or utility



Analysis of supplemental project under construction – by PJM's planning region



Analysis of supplemental project under construction – by State

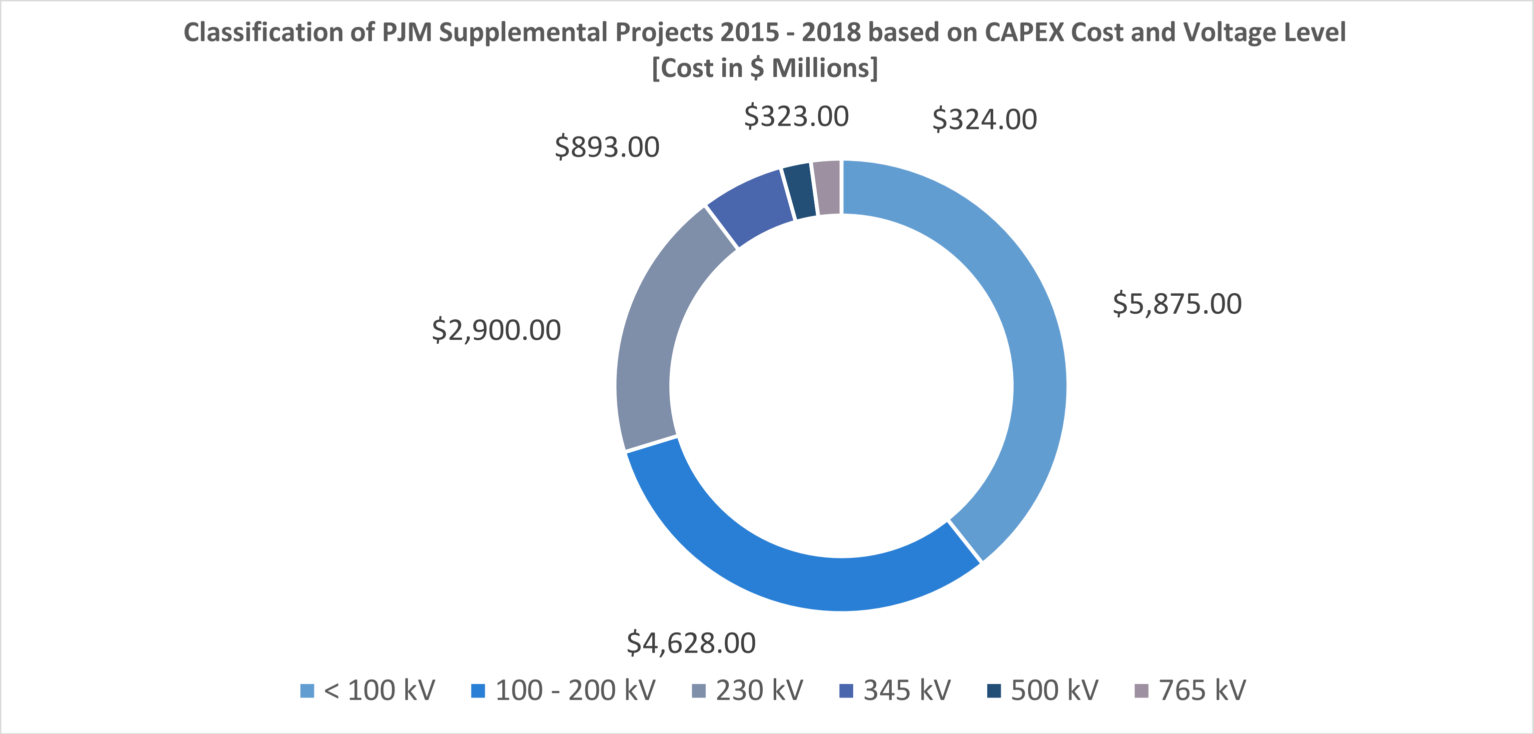


Additional Insights – PJM TEAC Meetings – January and February 2019

- In Feb. 2019, PJM presented additional insights on Supplemental Transmission Projects proposed in PJM footprint. Below are additional insights from those presentations*:
  - At end of 2018, total Supplemental Transmission Projects across PJM footprint topped $26B, an incremental increase of over $6B compared to Supplemental Transmission Projects proposed at the end of 2017
  - 2018 saw the largest increase in Supplemental Transmission Projects at over $5.7B. The second largest set of Supplemental Projects in PJM were proposed in 2015, totaling about $5.1B
  - Top three TOs proposing Supplemental Projects in PJM in 2018:
    - PSE&G - $1.6B
    - AEP - $2.4B
    - ATSI - $511M
- Top three TOs proposing Supplemental Projects in PJM since 2005:
  - PSE&G - $9.1B
  - AEP - $6.2B
  - PPL - $3.1B

*CAPEX and/ or cost numbers rounded to one decimal place, where applicable

Additional Insights – PJM TEAC Meetings – January and February 2019



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Appendix C

PJM Supplemental Transmission Projects: Planned and Completed in 2018

PJM Transmission Supplemental Projects: Planned and Completed in 2018

Analysis of PJM supplemental projects proposed to be completed and actually completed in 2018

February 14, 2019

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Source of information on supplemental projects

Sources (publicly available):

1. PJM Website (https://www.pjm.com/planning/rtep-upgrades-status/construct-status.aspx)
2. Transmission Cost Information Center (TCIC) (https://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx)
3. Other publicly available sources such as meeting material published on PJM committee meeting portals
4. Material published on PJM's regional subcommittee meeting portals

Data Processing:

1. CA performed extensive data scrubbing and filled in the data where it was missing, to the extent possible

Findings – Supplemental Projects Planned and Completed in 2018

- Total of 362 transmission supplemental projects were proposed and planned to be completed in CY 2018. Total CAPEX for all planned supplements projects was $2.97 B

- A total 114 transmission supplemental projects were actually completed in CY 2018 at a total CAPEX of $991.2 M

- Project realization (construction completed) rate of 33.4 percent

- Variety of projects completed construction based on capital cost:
  - Lowest cost supplemental project was $50,000 and involved installing a wave trap at an existing substation. Proposing TO was ComEd
  - Highest cost supplemental project was $156 M and involved building a 138 kV substation for four new 138 kV circuits. Proposing TO was PEPCO

Findings – Supplemental Projects Planned and Completed in 2018

- PSE&G had the largest CAPEX allocated to planned supplemental transmission projects at $838 M

- AEP had the second largest CAPEX allocated to planned supplemental transmission projects at $774 M

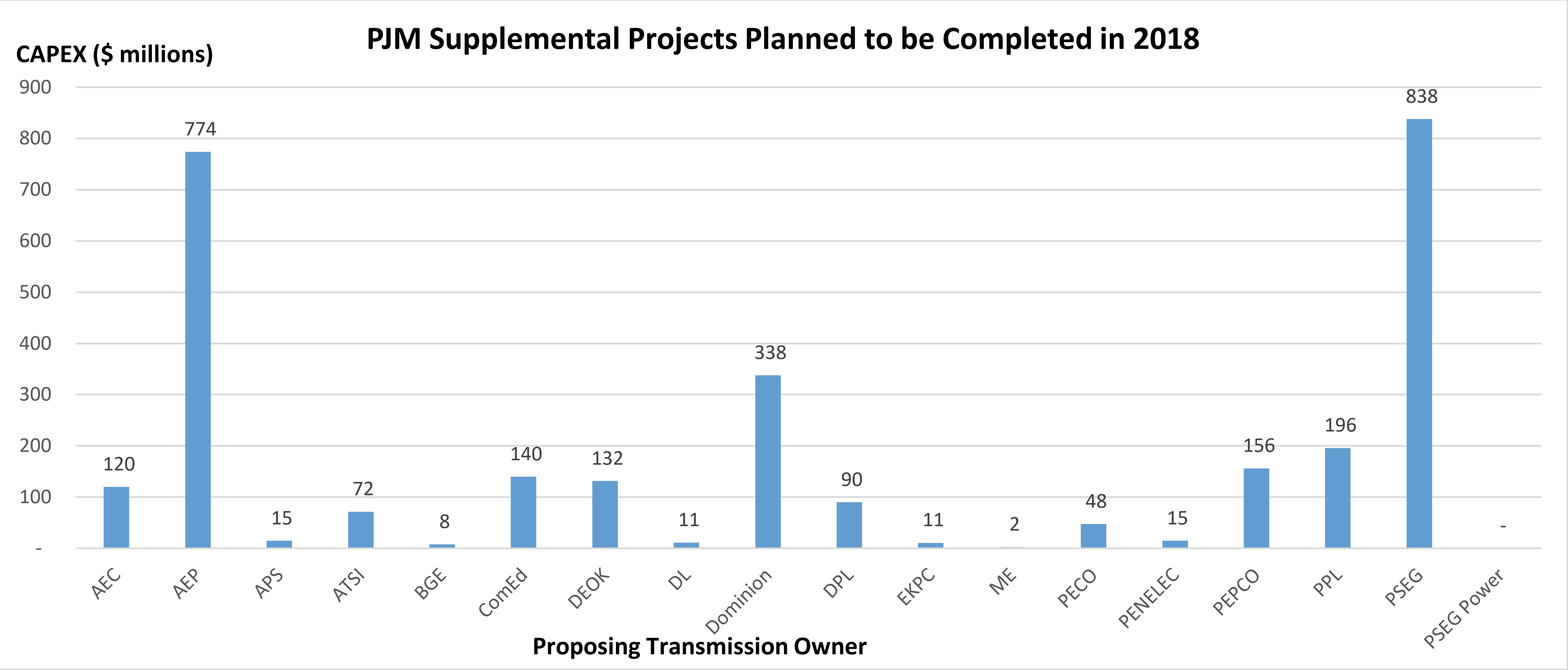
____

- AEP realized (construction completed) the maximum number of supplemental transmission projects at $264 M, a realization rate of about 34 percent

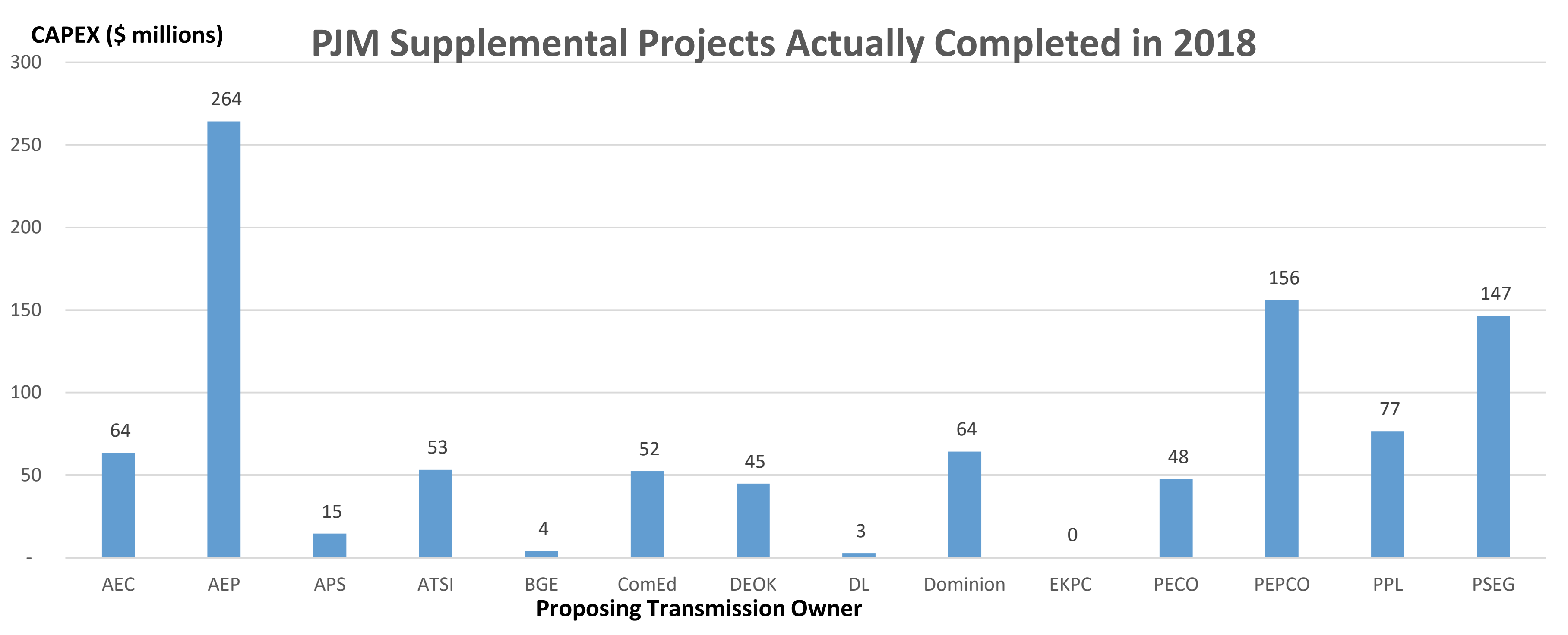
- PEPCO achieved a realization rate of 100 percent, completing construction of all supplemental projects that it had planned, at a total CAPEX of $156 M

- PSE&G realized supplemental transmission projects totaling $147 M, a realization rate of about 17.5 percent

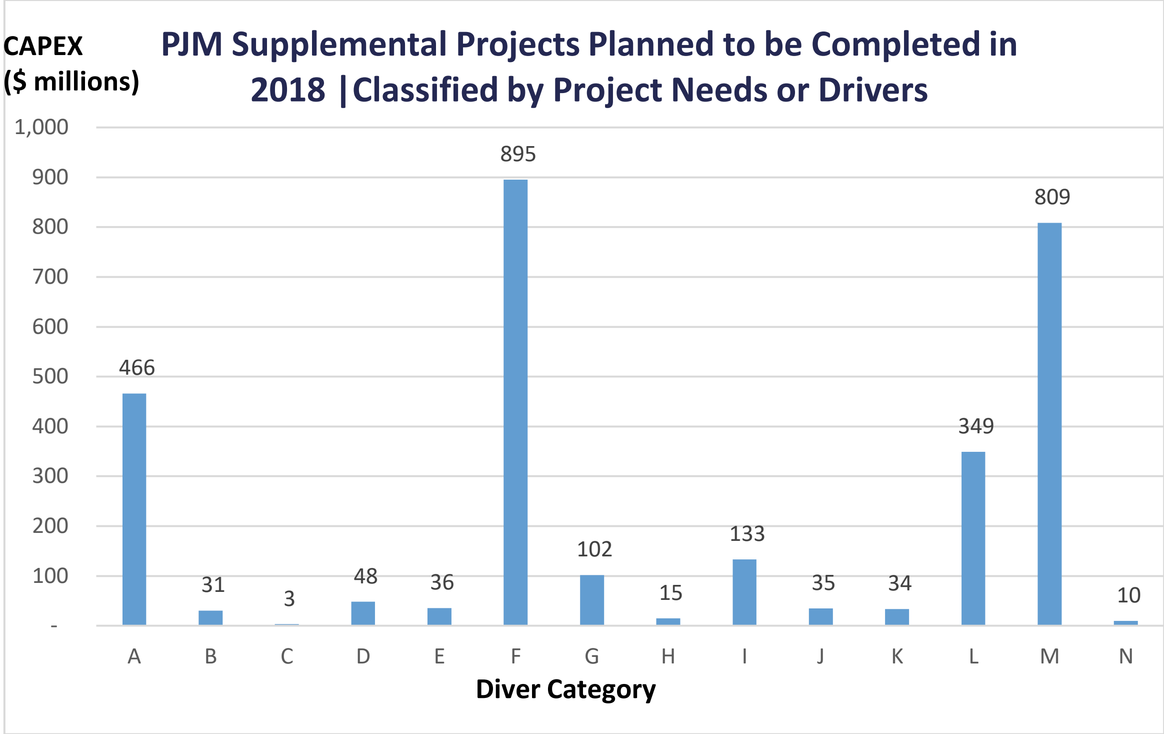
PJM Supplemental Projects Planned to be Completed in 2018 | Classified by Proposing TO



PJM Supplemental Projects Actually Completed in 2018 | Classified by Proposing TO

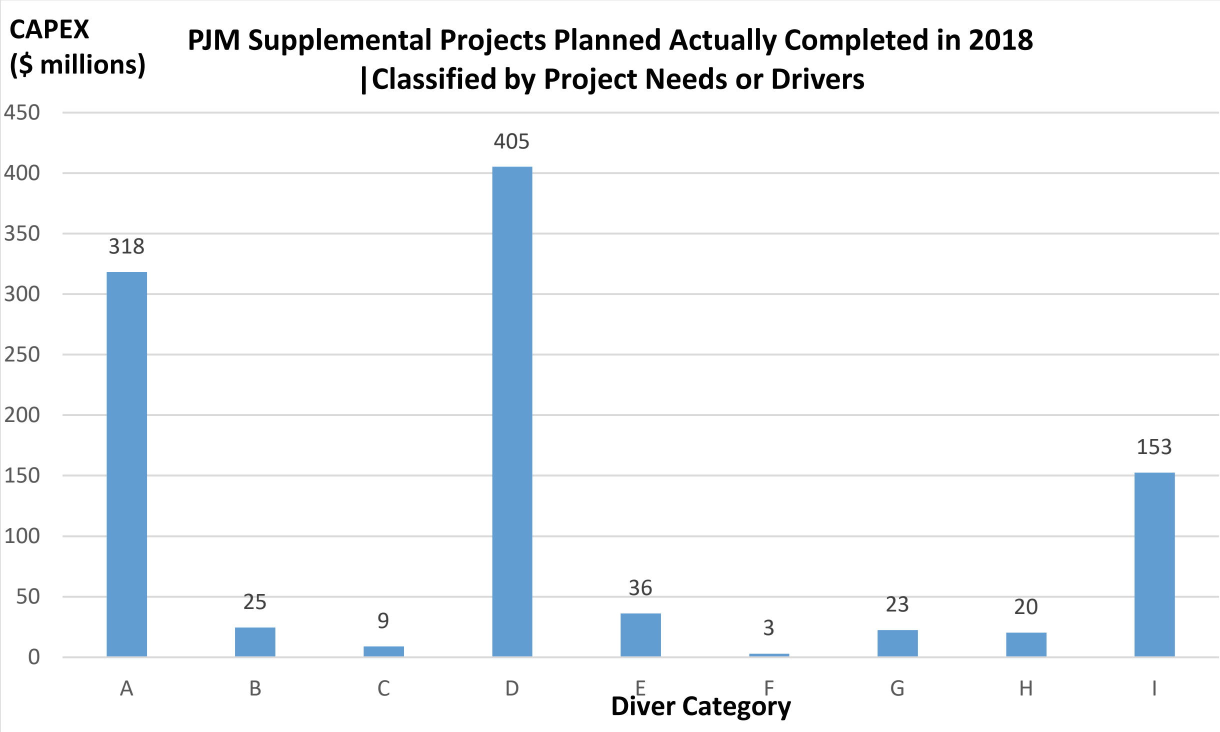


PJM Supplemental Projects Planned to be Completed in 2018 | Classified by Projects Needs or Drivers



Driver (Category)	Driver(Description)	Total
A	Customer Service	466
B	Customer Service / Equipment Material Condition, Performance and Risk	31
C	Customer Service / Equipment Material Condition, Performance and Risk / Infrastructure Resilience /	3
D	Customer Service / Equipment Material Condition, Performance and Risk / Operational Flexibility and	48
E	Customer Service / Operational Flexibility and Efficiency	36
F	Equipment Material Condition, Performance and Risk	895
G	Equipment Material Condition, Performance and Risk / Infrastructure Resilience	102
H	Equipment Material Condition, Performance and Risk / Infrastructure Resilience / Operational Flexibility and	15
I	Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency	133
J	Infrastructure Resilience	35
K	Infrastructure Resilience / Operational Flexibility and Efficiency	34
L	N/A	349
M	Operational Flexibility and Efficiency	809
N	Other	10
Total ($ in millions)		**2,965**

PJM Supplemental Projects Actually Completed in 2018 | Classified by Projects Needs or Drivers



Driver (Category)	Driver(Description)	Total
A		318
B	Customer Service / Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency	25
C	Customer Service / Operational Flexibility and Efficiency	9
D	Equipment Material Condition, Performance and Risk	405
E	Equipment Material Condition, Performance and Risk / Infrastructure Resilience	36
F	Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency	3
G	Infrastructure Resilience / Operational Flexibility and Efficiency	23
H	N/A	20
I	Operational Flexibility and Efficiency	153
Total ($ in millions)		991

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Appendix D

Summary of Certificate of Public Convenience and Necessity Requirements For PJM States

Summary of Certificate of Public Convenience and Necessity Requirements by PJM States[1]

Below is a summary of Certificate of Public Convenience and Necessity (CPCN) requirements for various PJM States and a link to CPCN related statutes on state regulator's website. Other sources included as pertinent and appropriate.

State	CPCN Requirements	Source and Link to State's Regulatory Statute for CPCN Requirements
Delaware	• One time CPCN requirement for first project above 34.5 kV in state • Not required for any construction, modification, upgrade or extension within the perimeter of any territory already served	3011 Rules for Certification of Electric Transmission Supplier; 3000 Energy Regulations http://regulations.delaware.gov/AdminCode/title26/3000/3011.pdf
Illinois	• Need a CPCN or Commission Order in order to use eminent domain authority • CPCN needed for new builds only of 100 kV or greater • Commission Order is required to make additions, extensions, repairs or improvements to, or changes in an existing plant or facility • No CPCN required if serving a single customer or a new generator interconnection, where the beneficiary owns the property to be used for the new transmission line or has secured necessary right of way	Article VIII of Illinois Public Utilities Act (220 ILCS 5/) Section 8-406 and 8-406.1
Indiana	• No CPCN required for electric power transmission lines. • CPCN is only required for power generation projects	-NA-
Kentucky	• CPCN is required for electric power transmission lines greater than 138 kV or more than one mile in length • Exemptions to CPCN requirement include ordinary extensions of existing systems in the usual course of business	Statute 278.020 of Kentucky Revised Statutes Chapter 278. 278.020 Certificate of convenience and necessity required for construction provision of utility service or of utility -- Exceptions --

[1] Input taken from Summary of CPCN Requirements by PJM State originally developed by LS Power

State	CPCN Requirements	Source and Link to State's Regulatory Statute for CPCN Requirements
		Approval required for acquisition or transfer of ownership -- Public hearing on proposed transmission line -- Limitations upon approval of application to transfer control of utility or to abandon or cease provision of services -- Hearing -- Severability of provisions.
Maryland	• Need a CPCN if overhead line greater than 69 kV • Need a CPCN to exercise condemnation Commission may waive requirement with "good cause" if construction related to existing transmission line **<u>and</u>** does not require additional acquisition by eminent domain or construction does not require larger and higher structures to accommodate increased voltage or larger conductors.	Maryland Public Utility Companies Section 7-207 and Section 7-208
Michigan	• No CPCN needed unless line 345 kV or higher, and 5 miles or longer in length. Voluntary below 345 kV, but a voluntary CPCN application will trump the local siting and zoning process. Voluntary CPCN approval will be "conclusive and binding" as to public convenience and necessity in eminent domain proceedings. • A certificate is not required for reconstructing, repairing, replacing or improving existing transmission line, including the addition of circuits to existing transmission line	ELECTRIC TRANSMISSION LINE CERTIFICATION ACT. Act 30 of 1995. Sections 460.561 through 460.575. Enrolled Senate Bill No. 408.
New Jersey	• No CPCN required for electric transmission projects	-NA-
North Carolina	• CPCN needed for any transmission line above 161 kV • CPCN exemption for the replacement or expansion of an existing line with a similar line in substantially the same location or for the purpose of increasing capacity or	NC - General Statutes of North Carolina Annotated > CHAPTER 62. PUBLIC UTILITIES > ARTICLE 5A. SITING OF TRANSMISSION LINES

State	CPCN Requirements	Source and Link to State's Regulatory Statute for CPCN Requirements
	widening of an existing right of way	
Ohio	• CPCN needed for any transmission line above 100 kV • Transmission line length threshold is greater than 2 miles for a standard application • Different thresholds for Letter of Notification Application and Construction Notice Application, which are lower than CPCN requirements.	Title 49 Public Utilities Code [http://codes.ohio.gov/orc/49] Chapter 4906 – Power Siting http://codes.ohio.gov/pdf/oh/admin/2018/4906-1-01_ff_n_app1_20151130_0921.pdf
Pennsylvania	• CPCN required for transmission lines over 100 kV, with no exception for rebuilds, repairs, or ordinary course of business	Chapter 57 of Pennsylvania State Utility Regulations Chapter 69 of Pennsylvania State Utility Regulations
Tennessee	• CPCN required for transmission, with no exception for rebuilds, repairs, or ordinary course of business for any entity not transmitting power as of March 1955 • CPCN for any line, plant or system serving a municipality already served by another public utility	
Virginia	• Incumbent utility may build certain transmission facilities without a CPCN, if they are "ordinary extensions. • Following categories of transmission projects are statute classified as "non-ordinary extensions"	Va. Code Ann. § 56-265.2(A)(1); tit. 5 Va. Admin Code 5-20-80. Va. Code Ann. § 56-265.1.

State	CPCN Requirements	Source and Link to State's Regulatory Statute for CPCN Requirements

	that require a CPCN:
	• 138 kV and above that:
	    • proposes construction of a new line more than 0.5 mile long;
	    • requires the use of new ROW not supplied voluntarily by the requesting customer(s) for which the project is being undertaken;
	    • includes the replacement of more than three existing structures; or
	    • requires the replacement of one or more existing structures with a structure that is more than 20% taller than an existing structure being replaced; or
		Va. Code Ann. § 15.2-2232
		
		Va. Code Ann. § 56-265.2(A)(2).;
		
		tit. 56 Va. Code Ann. § 56-265.2(A)(1)

West Virginia	• Certificate required for transmission line of 200 kV and above • Construction activities which deal with the in-kind replacement of existing facilities are not subject to the certification process • Statute provides CPCN requirement exemptions for "extensions during a normal course of business". The exemption has been highly subjective in the past.	CHAPTER 24 – Public Service Commission. Article 2. Powers and Duties of Public Service Commission. §24-2-11. Requirements for certificate of public convenience and necessity.