STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN RATE ADJUSTMENT; AND FOR APPROVAL OF RELATED RELIEF INCLUDING: (1) REVISED DEPRECIATION RATES; (2) ACCOUNTING RELIEF; (3) INCLUSION IN RATE BASE OF QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECT; (4) ENHANCEMENTS TO THE DRY SORBENT INJECTION SYSTEM; (5) ADVANCED METERING INFRASTRUCTURE; (6) RATE ADJUSTMENT MECHANISM PROPOSALS; AND (7) NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	)	**CAUSE NO. 45235**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 7

TESTIMONY OF

OUCC WITNESS MICHAEL GAHIMER

August 20, 2019

Respectfully submitted,

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TESTIMONY OF OUCC WITNESS MICHAEL GAHIMER
CAUSE NO. 45235
INDIANA MICHIGAN POWER COMPANY

I. INTRODUCTION

Q: Please state your name, business address, and employment capacity.

A: My name is Mike Gahimer and my business address is 115 W. Washington St., Suite 1500 South, Indianapolis, Indiana 46204. I am employed by the Indiana Office of Utility Consumer Counselor ("OUCC") as a Senior Utility Analyst in the Federal Division. My qualifications are set forth in Appendix A of this document.

Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A: Yes, during my first period of employment at the OUCC (1992-1995), I testified in numerous cases before the Commission. While I was employed at NIPSCO (1995-2000), I testified in cases before the Commission as well as in cases before the Federal Energy Regulatory Commission ("FERC").

Q: You referred to your "first period of employment at the OUCC." Why?

A: My current employment represents the second time in my career I have been employed by the OUCC.

Q: Would you please provide more detail with respect to your current role at the OUCC?

A: I participate in most planning, market, and transmission-related stakeholder meetings in the Midcontinent Independent System Operator ("MISO") and PJM. In most cases, my participation takes the form of personal attendance at meetings (either physically or telephonically). When circumstances prevent my personal attendance at meetings, my participation takes the form of pre-meeting reviews of materials and/or post-meeting follow-up with colleagues from other consumer advocate agencies (typically in the case of PJM) or state commissions (typically in the case of MISO). I am also an active participant in the Consumer Advocates of PJM States ("CAPS") which, as the name implies, is an organization comprised of consumer advocate agencies from every PJM state and the District of Columbia. CAPS facilitates and coordinates consumer advocate participation in PJM matters and supports its member agencies' advocacy. On most issues at PJM, I am one of the most active consumer advocate representatives.

Q: What is the purpose of your testimony in this Cause?

A: The purpose of my testimony in this Cause is three-fold. First, I will address Network Integration Transmission Services ("NITS") and I&M's proposed recovery of the costs incurred thereunder ("NITS Charges"). Second, I will reiterate and reinforce the OUCC's concern, as first expressed in testimony by OUCC Witness Dr. Peter Boerger in I&M's previous rate case (Cause No. 44967), with the current magnitude and expected dramatic growth of NITS Charges and propose future Commission action in that regard. Third, I will address I&M's request to recover the premium associated with the purchase of Capacity Performance Insurance.

Q: Please summarize your recommendations.

A: Regarding NITS Charges, I recommend the Commission reject I&M's request to recover NITS Charges through the OSS/PJM Rider. I also recommend the Commission include the estimated Test Year level of I&M's NITS Charges in base rates – subject to a compliance filing through which base rates are adjusted downward if I&M's actual NITS Charges are lower than the estimated level. Using I&M's WP-JCD-2, I show the Indiana jurisdictional amount of forecasted test year NITS Charges to be $233,040,725, and recommend this figure be embedded in I&M's base rates subject to the treatment described above.

Moreover, I&M's portrayal that NITS Charges are outside its control is inaccurate. I discuss why the Commission should be concerned about the current process. Given the lack of effective oversight over the planning of Supplemental Projects that result in NITS Charges to I&M, I recommend the Commission open an investigation to ensure transmission investments that wind up in I&M's electric rates are prudent. The Commission should explore the potential to (1) assess the prudency of Supplemental Projects built in Indiana and (2) shield I&M's electric customers from the costs of Supplemental Projects built outside of Indiana, but in the AEP East zone, before those Supplemental Projects are included in I&M's FERC Formula Rate Filing.

Finally, I recommend the Commission deny I&M's request to recover costs associated with Capacity Performance Insurance in rates. I&M's O&M Adjustment 6 to the forecasted Test Year shows a Total Company miscellaneous expense for Capacity Performance Insurance of $1,513,220. I discuss the reasons below.

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with Petitioner's proposal?

A: No. Excluding any specific adjustments or amounts proposed by I&M from my testimony does not indicate my approval of those adjustments or amounts, but rather that the scope of my testimony is limited to the specific items addressed herein.

II. <u>NITS CHARGES</u>

Q: What is NITS?

A: NITS is a transmission service in the PJM Regional Transmission Organization ("RTO") that allows a transmission customer to integrate its dispersed generation to serve its dispersed load. In PJM, a transmission owner ("TO") provides NITS under the rates and terms of service of the Open Access Transmission Tariff ("OATT").[1] A TO's rates for NITS are included in its respective FERC-approved OATT. For example, OATT Attachment H-14 corresponds to service provided by the American Electric Power ("AEP") East Operating Companies ("AEP East OpCo"), while OATT Attachment H-20 corresponds to service provided by the AEP Transmission Companies (AEP East TransCo").

Q: Does I&M pay other types of PJM costs?

A: Yes. I&M generally categorizes PJM charges as either NITS Charges or non-NITS charges ("Non-NITS Charges").[2] My testimony will focus on NITS Charges because, as opposed to Non-NITS Charges, they are the largest and most dramatically increasing new transmission cost category by PJM TOs.

Q: In what role and from whom does I&M purchase NITS?

A: I&M performs three roles in PJM - a generator, a TO and a load serving entity ("LSE"). In its role as LSE, I&M buys NITS from itself and other AEP entities in their roles as TOs. The NITS revenue requirement for AEP East OpCo (Attachment H-14 referenced above) is based on the combined NITS rate base of all of AEP's Operating Companies in PJM.[3] The revenue requirement for AEP East TransCo (Attachment H-20 referenced above) is based on the combined NITS rate base of all of the AEP

[1] The OATT is a FERC-approved tariff that contains the terms and conditions for transmission service.
[2] See Direct Testimony of Kamran Ali, p. 8 (discussion of Non-NITS Charges).
[3] The AEP Operating Companies are Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company.

Transmission Companies in PJM.[4] Pursuant to Appendix I of the AEP Transmission Agreement,[5] NITS Charges for each AEP Operating Company's retail load are based on its contribution to the average of the 12 coincident peaks through October 31st of the prior year. The NITS Charges for each AEP Operating Company are *not* based on the revenue requirement resulting from the AEP OpCo and AEP TransCo projects in that AEP Operating Company's service territory. The NITS Charges recovered through I&M's retail rates pay for a share of every Attachment H-14 and H-20-related transmission facility that exists in any AEP Operating Company service territory in PJM.

Q: How does I&M propose to recover NITS Charges?

A: I&M proposes to recover 100% of its NITS Charges through its Off System Sales Margin Sharing/PJM Cost Rider ("OSS/PJM Rider").[6]

Q: Does I&M explain why it thinks such tracker recovery is reasonable?

A: Yes. I&M witness Kamran Ali states that "in determining whether to approve the tracking of costs, the Commission considers whether the costs are (1) collectively and potentially significant; (2) potentially variable or volatile; and (3) largely outside the utility's control."[7] Mr. Ali states that NITS Charges satisfy each of those tracker-eligibility considerations.[8]

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[4] The AEP Transmission Companies are AEP Appalachian Transmission Company Inc., AEP Indiana Michigan Transmission Company Inc., AEP Kentucky Transmission Company Inc., AEP Ohio Transmission Company Inc., and AEP West Virginia Transmission Company Inc.
[5] Attachment KA-3 to the Direct Testimony of Kamran Ali, p. 15.
[6] Direct Testimony of Kamran Ali, p. 2, lines 17-19.
[7] *Id.*, p. 19, lines 8-16. These three considerations were set forth by Commission in its Final Orders in Cause No. 43259 at page 115, (PSI Energy Inc. rate case) and Cause No. 44576 at page 79, (Indianapolis Power & Light Company rate case).
[8] *Id.*, p. 20, line 20 – p. 21, line 6.

Q: Do you agree that NITS Charges are largely outside of the utility's control?

A: No, I do not. NITS Charges are largely within I&M's and the other AEP-affiliated TOs' (collectively, "AEP TOs") control.

Q: You refer to AEP-affiliated TOs' control in a plural sense, yet, the Commission consideration relating to control refers to "utility" in a singular sense. Are you attempting to expand the Commission's previously stated considerations?

A: No, I am not. I am merely applying them to the unique situation that has been created by past decisions made somewhere in the AEP corporate family ("AEP Corporate Decisions").

Q: To what AEP Corporate Decisions are you referring?

A: I am specifically referring to decisions made in (1) developing and maintaining the AEP corporate structure and (2) creating, modifying and maintaining the AEP Transmission Agreement. The AEP Transmission Agreement is included in Attachment KA-3 to Mr. Ali's testimony.

Q: Please explain the relevant AEP Corporate Decisions made by AEP relating to its corporate structure.

A: A corporate structure was developed and maintained under which, within the footprint of each of the AEP Operating Companies, transmission assets can be owned by each of two (2) AEP-affiliated TOs: (1) the utility itself and (2) an AEP transmission company corporately separate from the utility. In I&M's service territory, transmission is owned by Indiana Michigan Power Company (I&M) and AEP Indiana Michigan Transmission Company Inc. ("I&M Transco").

Q: Please explain the relevant choices made by AEP relating to the AEP Transmission Agreement.

A: Through the AEP Transmission Agreement, each of the AEP Operating Companies providing utility service in PJM's footprint pays a share of the NITS costs associated with every Attachment H-14 and H-20 transmission facility in the PJM AEP East footprint, not just those projects it owns or even those in its own service territory.[9]

Q: What is the practical effect of these AEP Corporate Decisions?

A: Through these AEP Corporate Decisions, some of I&M's control over its NITS Charges was ceded to the other AEP-affiliated TOs in the PJM footprint. So, in referring to the AEP TOs in the plural sense, I am not suggesting that the Commission should expand its "control" consideration. Rather, the Commission should recognize the unique situation caused by the referenced AEP Corporate Decisions and, in light of them, "deem" I&M to still have control that the AEP Corporate Decisions ceded on I&M's behalf to other AEP-affiliated TOs.

Q: You said some of I&M's control over its NITS Charges is ceded to other AEP-affiliated TOs. Doesn't that support I&M's claim that NITS Charges are outside of its control?

A: No, it does not. As mentioned above, because that control was ceded voluntarily by AEP Corporate Decisions, the Commission should "deem" I&M to still have the same level of control that it had before the control was ceded. AEP should not be able to justify tracker recovery based on a lack of control that AEP Corporate Decisions created.

Q: Does the fact that the AEP Transmission Agreement shifts some of I&M's transmission costs to other AEP utilities in the PJM footprint affect your analysis?

A: No it does not. By shifting some of I&M's transmission costs to other AEP utilities, the AEP Transmission Agreement effectively cedes some of the other AEP utilities' control to I&M *while* ceding some of I&M's control to them. In this regard, it doesn't matter that ceding is multi-directional. It only matters that some of I&M's control was ceded.

Q: Do I&M and the AEP TOs have control over NITS Charges?

A: Yes, this section of my testimony describes in detail how, contrary to I&M's assertion, I&M and the AEP TOs exercise significant control over the projects and costs that drive NITS Charges. Before offering that analysis, I want to highlight a relevant portion of AEP's annual incentive pay plan, which is discussed in greater detail in the testimony of OUCC witness Mark Garrett. AEP's annual incentive pay includes an incentive component based on its transmission infrastructure investment:

> If AEP's transmission infrastructure spending is below the threshold level of $3.310 billion, there is 0% payout for this metric. If AEP meets the transmission infrastructure target of $3.519 billion, the Plan is funded at 100% payout level, and if the maximum target of $3,655 billion is achieved, the Plan is funded at 200%.[10]

In weighing the credibility of I&M's assertion that it has no control over NITS Charges, the Commission should keep in mind how unlikely it is that AEP would incentivize something over which it had no control. AEP employees stand to directly benefit from the incentives to invest in transmission, so it stands to reason that AEP must have control over that investment.

Q: Does Mr. Ali explain why he thinks NITS Charges are largely outside of I&M's control?

A: Yes. To support his claim that NITS Charges are largely outside of I&M's control, Mr. Ali attempts to frame the issue of control by focusing attention on the conditions that cause the AEP TOs to consider additional investments in transmission ("Needs"),

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[10] Direct Testimony of Mark Garrett, p. 12, lines 6-9.

rather than on the decisions that they make in response to those Needs ("Projects"). The effect is to shift focus away from the very activity that gives the AEP TOs control over NITS Charges: transmission planning – which I will discuss below. Mr. Ali presents the drivers ("drivers" are the same as what I refer to above as Needs) considered by I&M in identifying what Mr. Ali labels Owner Projects.[11] He states that many of the drivers are outside of I&M's control,[12] although whether or not that is true is irrelevant.

Q: Why isn't control over "drivers" relevant?

A: Mr. Ali's focus on drivers is misplaced, as control is found in decision-making, not in inputs to that decision-making. Needs are inputs. Projects (and, thus, NITS Charges) result from decision-making in response to those Needs. Control over the incurrence of NITS Charges in *response* to the drivers is. For example, Mr. Ali presents asset performance as one of the drivers of projects and states that asset performance is outside of I&M's control. Assuming *arguendo* that asset performance is outside of I&M's control, that assumed fact doesn't mean I&M lacks control over the replacement of assets (and thus, over NITS Charges). In fact, Mr. Ali even concedes that I&M has such control:

> Although **I&M has some control over its own specific asset replacement** if the replacement is made before the asset's failure, many of the underlying drivers of asset performance such as equipment age, equipment abnormalities and environmental conditions are also outside of the Company's control.[13] (Emphasis added.)

[11] *Id.*, p. 12, line 12 – p. 13, line 10.
[12] *Id.*, p. 13, lines 11-21.
[13] *Id.*, p. 12, lines 12 - 21.

Even if deterioration of asset performance was completely outside of I&M's control, actions taken in response to that deterioration are within I&M's control. It can choose whether, when, with what and how to replace aging assets. Those decisions result in NITS Charges and involve judgment. Where there is judgment in decision making, there is control.

Q: Please discuss the transmission planning processes as they relate to I&M's control over NITS Charges.

A: There are different categories of transmission projects. The substantial control that AEP TOs have over NITS Charges can best be highlighted by contrasting the planning processes involved in two (2) of them.

Q: What are the different categories of transmission projects?

A: PJM defines three (3) categories of transmission projects: Baseline Projects, Supplemental Projects, and Network Upgrades. The fourth type of transmission project, Non-Topology Projects, are those that do not affect the flow of electrons, so I&M does not need to present them to PJM. Consequently, PJM does not have a category for them.

Q: How does PJM define the three (3) categories?

A: PJM describes the categories as follows:

> Baseline Projects include projects planned for (i) reliability, (ii) operational performance, (iii) FERC Form No. 715 criteria, (iv) economic planning, and (v) public policy planning (State Agreement Approach). Supplemental Projects refers to transmission expansion or enhancements *not needed to comply with PJM reliability, operational performance, FERC Form No. 715, economic criteria or State Agreement Approach projects. Transmission Owners plan Supplemental Projects in accordance with the Attachment M-3 Process.* Projects planned through the Attachment M-3 Process include those that expand or enhance the transmission system and could include needs addressing transmission facilities at the end of their useful life, which,

> in accordance with good utility practice, is not determined by the facility's service life for accounting or depreciation purposes. Customer-Funded Upgrades refer to Network Upgrades, Local Upgrades or Merchant Network Upgrades identified pursuant to OATT Parts II, III and VI and paid for by the Interconnection Customer or Eligible Customer or voluntarily undertaken by a New Service Customer in fulfillment of an Upgrade Request.[14] (Emphasis added).

Q: Which of the four (4) categories include projects that can result in NITS Charges?

A: NITS Charges can result from Baseline Projects, Supplemental Projects and Non-Topology Projects. Since Network Upgrades are paid for by customers, they do not result in a TO's NITS Charge. Because Non-Topology Projects are in relevant respects similar to Supplemental Projects, I will refer to Supplemental Projects and Non-Topology collectively as Supplemental Projects.

Q: Has I&M provided any information that allows you to conclude which type of project – Baseline or Supplemental – represents the lion's share of new transmission investment?

A: Yes. I&M agreed to provide a status report on its 2019 NITS projects in its last rate case, which I have attached to my testimony as Attachment MG-1. The data in Attachment MG-1 shows that I&M expects the following transmission projects to be started by either I&M or I&M Transco in its service territory this year: one Baseline Project; seven Non-Topology Projects; eighteen Supplemental Projects; and, one combined Baseline/Supplemental Project. While most new transmission projects used to be Baseline Projects, currently (and for the foreseeable future) costs for new transmission projects are and will be predominantly for Supplemental Projects.

[14] PJM Manual 14B: Region Transmission Planning Process, pp. 17-18 (Revision: 44, Effective Date: 02/21/2019 PJM 2019). Available at: https://www.pjm.com/-/media/documents/manuals/m14b.ashx.

Q: Does PJM present information regarding transmission plans?

A: Yes. In a January 10, 2019 presentation to the Transmission Expansion Advisory Committee ("TEAC"), PJM presented a set of instructive transmission project statistics.[15] I have attached the presentation as Attachment MG-2 and included three (3) tables from the slide deck as Figures MG-1 through MG-3.

[15] https://www.pjm.com/-/media/committees-groups/committees/teac/20190110/20190110-project-statistics-2018.ashx.

Figure MG-1

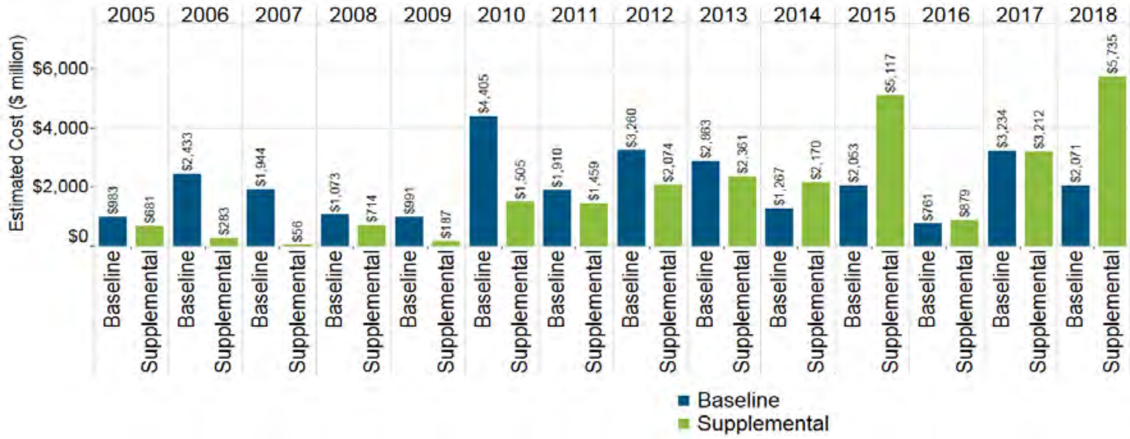


Figure MG-2

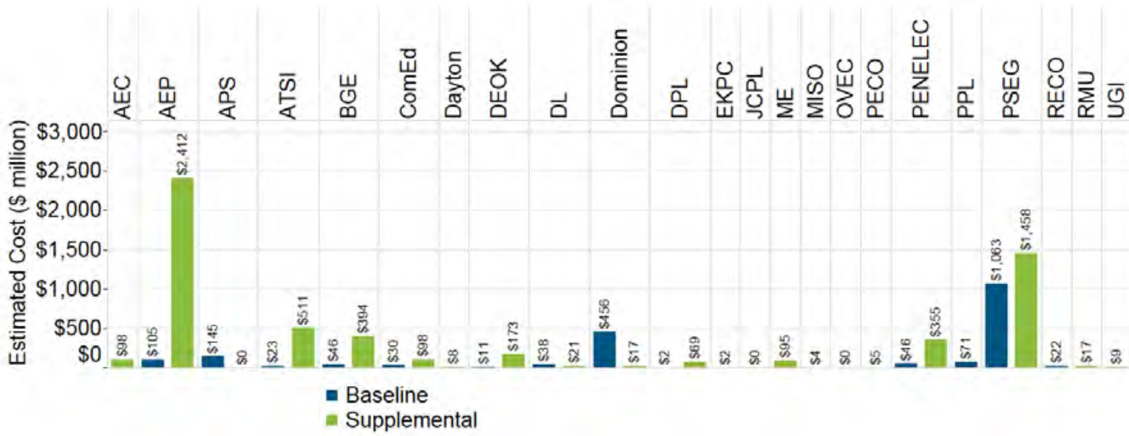
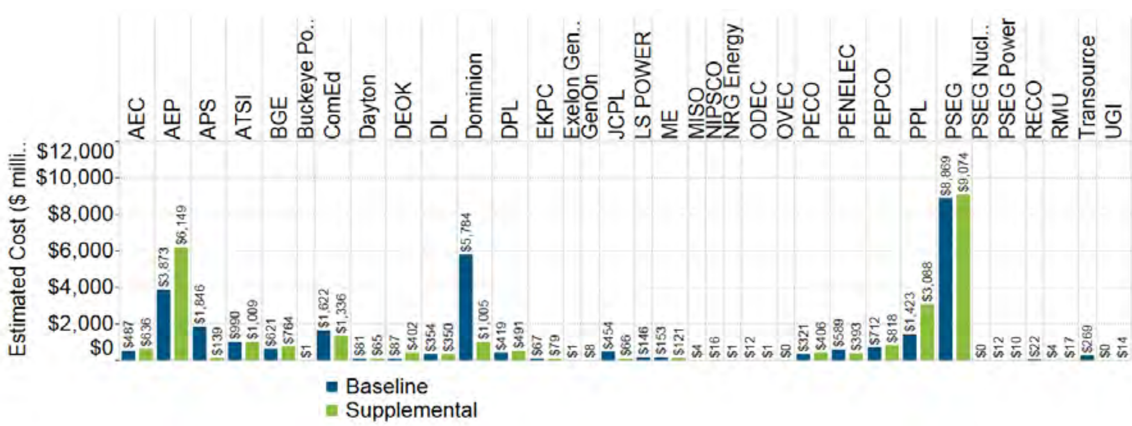


Figure MG-3



Q: Please generally describe Figures MG-1 through MG-3.

A: In each of the Figures, PJM shows the total estimated cost of the transmission projects included in the Regional Transmission Expansion Plan ("RTEP") broken out between Baseline Projects (planned and approved by PJM for inclusion in the RTEP) and Supplemental Projects (planned and approved by TOs for inclusion in the RTEP).[16] Each Figure addresses a different scale (either 2018 or 2005-2018, inclusive) and scope (either RTO-wide or broken down by TO) combination. In Figure MG-1, PJM shows the total estimated cost RTO-wide of all Baseline and Supplemental Projects that were included in each year's RTEP for 2005-2018, inclusive. In Figure MG-2, PJM shows the total estimated costs broken down by TO of all Baseline and Supplemental Projects included in the 2018 RTEP. In Figure MG-3, PJM shows the estimated costs broken down by TO of all Baseline and Supplemental Projects included in the RTEP from 2005-2018 summed across all years.

Q: What does Figure MG-1 show?

A: Figure MG-1 shows graphically the extent to which costs associated with Supplemental Projects have grown across the PJM footprint. It confirms that current and future costs for new transmission projects will be predominantly for Supplemental Projects. In 2018, $2.071 billion in Baseline Projects were approved and $5.735 billion in Supplemental Projects were submitted.

[16] As I discuss elsewhere, the PJM and its Board of Managers have no role in the approval of Supplemental Projects; therefore, the corollary to Baseline Projects' status of "planned by PJM and approved by the PJM Board of Managers" is Supplemental Projects' status of "planned by TOs and submitted by TOs to PJM for inclusion in the RTEP."

Q: What about Figures MG-2 and MG-3?

A: Figures MG-2 and MG-3 both relate specifically to the AEP TOs. Figure MG-2 shows that in 2018, $105 million in Baseline Projects were approved and $2.412 billion of Supplemental Projects were submitted. Figure MG-3 shows that during the time period of 2005 through 2018, inclusive, PJM approved $3.873 billion in Baseline Projects, and $6.149 billion in Supplemental Projects were submitted. Taken together, these Figures demonstrate that the cost of Supplemental Projects submitted by the AEP TOs in 2018 alone was more than 64% of the cost of Supplemental Projects submitted by them in the prior 13 years combined.

Q: Why is the migration of new transmission projects from Baseline to Supplemental important in this case?

A: PJM has control over the planning of Baseline Projects. TOs have control over the planning of Supplemental Projects. NITS Charges are no longer largely outside of the AEP TOs' control. There are two planning differences between Baseline and Supplemental Projects that determine control over NITS Charges: (1) the Needs that each category is intended to satisfy and (2) the processes by which each category's (a) Needs are identified and (b) projects are selected and approved to satisfy those Needs.

Q: What Needs are addressed by Baseline Projects?

A: The PJM Manual 14B language I included above shows that Baseline Projects are required to satisfy reliability criteria as established by either PJM, the North American Electric Reliability Corporation, ("NERC"), Reliability First Corporation ("RFC") or a TO's FERC Form 715. Baseline Projects are also required to relieve congestion, improve operational performance or meet a public policy goal.

Q: By whom are Baseline Needs identified and Baseline Projects selected and approved?

A: The Needs for Baseline Projects are identified by PJM, and once identified, PJM is in control of the planning process. PJM is responsible for ensuring that the best solution(s) is (are) developed to meet Baseline Needs. PJM selects projects to recommend to the PJM Board of Managers ("Board"). The Board approves the Baseline Projects to be included in the RTEP.

Q: What Needs are addressed by Supplemental Projects?

A: PJM's Manual 14B defines Supplemental Projects not by what Needs they are intended to meet but rather by what Needs they are *not* intended to meet.

Q: By whom are Supplemental Needs identified and Supplemental Projects selected and approved?

A: The Needs for Supplemental Projects are identified by the TOs. For example, the AEP TOs identify the Needs that result in Supplemental Projects in I&M's service territory. Mr. Ali describes Supplemental Projects as being needed "for many reasons, including regulatory requirements, modernization and hardening of the grid, replacement of failed equipment, proactive replacement of deteriorating assets prior to failure and improved operational efficiency and performance."[17] The TOs have developed a list of Needs to be met by Supplemental Projects to aid in their categorization: (1) Equipment Material Condition, Performance, and Risk; (2) Operational Flexibility and Efficiency; (3) Infrastructure Resilience; (4) Customer

[17] Direct Testimony of Kamran Ali, p. 11, lines 16-19.

Service; and, (5) Other Drivers.[18] Once Supplemental Needs are identified, the TO retains control of the planning process through what is referred to as the M-3 Process.

Q: Are Supplemental Projects required by PJM?

A: No.

Q: How does I&M identify Needs for Supplemental Projects?

A: Mr. Ali's testimony states that such projects are chosen through the use of AEP's Guideline for Transmission Owner Identified Needs,[19] which he says "assures only projects that are needed in each [TO's] service territory are pursued."[20]

Q: Does I&M address the PJM M-3 Process?

A: It does, but not by name. Mr. Ali states:

> To ensure that Owner Project[21] needs are clearly understood by stakeholders, they are vetted with stakeholders through PJM hosted stakeholder meetings. This transparent planning and vetting process ensures that Owner Projects that are incorporated into the RTEP are appropriate, efficient, and cost-effective solutions to planning criteria and system needs that benefit customers.[22]

When Mr. Ali refers to the planning and vetting process, he is talking about the M-3 Process. I have set forth the M-3 Process in detail in my Appendix B. In brief, the M-3 Process does not, in fact, "ensure that Owner Projects that are incorporated into the RTEP are appropriate."

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[18] TO presentation to PJM stakeholders attached as Attachment MG-4. These are not designations. The TOs have adopted them for convenience.
[19] *Id.*, Attachment KA-1.
[20] *Id.*, Ali, p. 12, lines 1-6.
[21] Owner Projects are the same thing as Supplemental Projects.
[22] *Id.*, p. 21, lines 9 - 14.

Q: What are the important facts the Commission needs to know about Supplemental Projects and the M-3 Process?

A: PJM does not recommend, require, review for prudency or approve Supplemental Projects. Supplemental Projects are included in a review process where TOs can receive – and ignore without consequence – input from other parties.

Q: Should this process cause the Commission concern?

A: Yes. TOs portray NITS Charges as being largely outside of their control.[23] Processes such as PJM's M-3 Process provide insufficient oversight of Supplemental Projects, the largest category of NITS Charges. The TO identifies and determines Supplemental Projects' underlying Need, scope and scale, design, and no other party is requiring them to be built. In short, the entire planning process from Need identification to submission for inclusion in the RTEP is entirely within the utilities' control and is subject to little, if any, effective oversight.

Q: How do you respond to I&M's assertion that Supplemental Projects are needed to maintain reliability of the grid and I&M's system?

A: Necessity does not determine whether NITS Charges should be recovered through I&M's base rates or through a tracking mechanism. Rate recovery hinges on control over the costs, not need. AEP TOs have control over I&M's NITS Charges because they have control over the projects chosen to be included.

Q: Has the Commission approved the recovery of NITS Charges associated with Supplemental Projects without a CPCN or other Commission review of the proposed projects?

A: Yes. The Commission has approved NITS Charges associated with Supplemental Projects and has approved NITS recovery through I&M's PJM tracker.

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[23] I&M witness Mr. Ali states that "many of the drivers of Owner Projects are outside I&M's control[.]" Direct Testimony of Kamran Ali, p. 13, lines 14-15.

Q: Has the Commission exercised oversight or sought to review PJM Supplemental Projects for prudency or compliance?

A: Not to my knowledge.

Q: The costs of Supplemental Projects are recovered by the AEP TOs from I&M in its role as LSE through each TO's corresponding Attachment H to PJM's OATT. By whom and under what process are those Attachment H rates approved?

A: The rates included in a TOs corresponding Attachment H are approved by FERC pursuant to a process known as a Formula Rate Filing. A Sub-Attachment to each TO's Attachment H identifies the protocols under which its Formula Rate process will be prosecuted. Each LSE then seeks recovery, as I&M has in this case, from its captive ratepayers.

Q: Since NITS Charges are approved by FERC pursuant to Formula Rate Filings, should the Commission forego any attempt to ensure that transmission projects for which I&M electric customers are paying represent prudent investments?

A: No. The fact that the Commission approves investment in transmission for some utilities through Transmission and Distribution System Improvement Charge ("TDSIC") cases shows that the Commission regularly reviews the prudence of transmission projects before Indiana TOs can include those costs in retail rates. Moreover, the FERC Formula Rate Filings offer little opportunity for Indiana customers or consumer advocates to challenge prudence, especially regarding projects outside of Indiana. Nonetheless, such charges are assessed on I&M customers through AEP's sharing of NITS charges across the AEP East footprint.[24] This process does not

[24] For example, assume that Wheeling Power includes costs associated with a Supplemental Project related to a claimed expectation of future load growth in its service territory in a Formula Rate Filing. The OUCC would only see the one or two page presentation in the appropriate Sub-Regional meeting, and likely wouldn't be able to ask enough questions and get answers either in the Sub-Regional meeting or at FERC to properly assess the need for the project, let alone the propriety of its design, costs, etc. Assuming the OUCC was able to assess that

provide I&M customers with any assurance that the rates they pay their regulated utility are just and reasonable.

Q: Doesn't your recommendation contravene PJM processes?

A: No. My recommendation asks the Commission to exercise the jurisdiction it already has over transmission and distribution projects. When the Commission reviews a TDSIC petition, a utility is required to show the prudence and necessity of the proposed projects, and cannot recover the projects' costs until it has made that showing. Because I&M is a member of PJM, it uses the NITS process instead, which has the effect of avoiding Commission oversight. It doesn't stand to reason that I&M can avoid this review simply by not filing for approval of a TDSIC plan.

III. NITS RECOMMENDATIONS

Q: What are your recommendations to the Commission relating to NITS Charges?

A: First, in light of I&M's and the other AEP TOs significant control over NITS Charges, I recommend the Commission reject I&M's request to recover NITS Charges through the OSS/PJM Rider. Second, I recommend that the Commission include the estimated Test Year level of I&M's NITS Charges in base rates – subject to a compliance filing through which base rates are adjusted downward if I&M's actual NITS Charges are lower than the estimated level.

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a project was imprudent, the OUCC would be faced with the logistical difficulty of arguing with FERC over a non-Indiana project, the need and location of which isn't likely to get FERC's attention.

Q: What amount do you recommend that I&M embed in its rates for NITS?

A: Based on the review performed by OUCC accountants and information obtained therefrom, I recommend the following: From WP-JCD-2 in Adj. No. 6 (RIDER-2), the Indiana jurisdictional component of NITS revenue requirement is the sum of 5 lines:

Increase 456-Other Electric Rev. Production-Retail Demand:	$107,210,992
Increase 456-Other Electric Rev. Production-Retail Energy:	$983,631
Decrease 5650015-PJM TO Serv Exp – Aff:	$1,367,017
Decrease 5650016-PJM NITS Expense – Affiliated:	$122,986,184
Decrease 5650021-PJM NITS Expense Non-Affiliate:	$492,901
Total:	**$233,040,725**

This number should be embedded in rates, and is reflected in the base rate revenue requirement in Mr. Garrett's testimony.

Q: What are your recommendations to the Commission relating to your concern over the magnitude and growth of NITS Charges?

A: I recommend that the Commission open an investigation to ensure transmission investments that wind up in I&M's electric rates are prudent, given the lack of effective oversight over the planning of Supplemental Projects that result in NITS Charges to I&M. The Commission should explore the potential to (1) assess the prudency of Supplemental Projects built in Indiana and (2) shield I&M's electric customers from the costs of Supplemental Projects built outside of Indiana, but in the AEP East zone, before those Supplemental Projects are included in I&M's FERC Formula Rate Filing.

Q: Are you questioning the validity of I&M's proposed Supplemental Projects?

A: No, but I also cannot verify that the projects are needed.

Q: Does your recommendation punish I&M for using the M-3 Process, which FERC has allowed?

A: No. While it is true that FERC approved the M-3 Process, that approval does not govern how or if those costs are recovered by I&M in rates. I&M is asking this Commission to approve recovery of NITS Charges that flow from Supplemental Projects over which the AEP TOs have control, whether through base rates or through a tracker. It is uncontested that the timing and number of Supplemental Projects is not mandated by PJM. The timing and number of Supplemental Projects leading to I&M's NITS Charges are within the AEP TO's control. The evidence demonstrates that there is an incentive compensation plan to grow these projects. The Commission has the power and duty to ensure that rates are just and reasonable, and a close examination of the prudency and cost of Supplemental Projects is squarely within that mandate. Once that review has been completed, it is appropriate for those costs to be included in base rates.

IV. CAPACITY PERFORMANCE INSURANCE

Q: What is Capacity Performance?

A: Capacity Performance, sometimes referred to as a pay-for-performance requirement, is a set of rules PJM implemented in the wake of the Polar Vortex in 2014 to provide incentives (in the form of both a "stick" and a "carrot") for generator resources to invest in upgrades that would better enable them to be available when needed during times of system stress. In this way, the risk of non-performance was said to be transferred from load to generators. The details of Capacity Performance are covered in PJM's Manual 18.[25]

[25] https://www.pjm.com/-/media/documents/manuals/m18.ashx

Q: When did PJM implement Capacity Performance?

A: PJM began a phased implementation of Capacity Performance in the 2016/2017 Delivery Year.[26] While Capacity Performance won't be fully implemented until the 2020/2021 Delivery Year, it began applying to Fixed Resource Requirement ("FRR") electors such as I&M this Delivery Year (2019/2020).

Q: Please explain the "stick" and "carrot".

A: Under Capacity Performance, PJM established Non-Performance Charges (the stick, or "Penalty") and Bonus Performance Credits (the carrot, or "Bonus Credit") that would apply to any Capacity Performance generation resource ("Resource") that performed worse or better than expected, respectively, during Performance Assessment Intervals ("PAI"). To determine whether a Resource performed worse or better, PJM calculates an expected output ("Expected Performance") using a complicated formula and subtracts from it the Resource's metered output ("Actual Performance"). The value of the Expected Performance minus the Actual Performance is referred to as the Performance Shortfall. A positive Performance Shortfall indicates performance was worse than expected. A negative Performance Shortfall indicates performance was better than expected.

Q: What is a Performance Assessment Interval?

A: A Performance Assessment Interval is any 5-minute interval during which PJM declares one of the following:

[26] Each Delivery Year runs from June in one year through May in the following year. The 2016/2017 Delivery Year ran from June 1, 2016 through May 31, 2017.

- Pre-emergency load management reduction action;
- Emergency load management reduction action;
- Primary reserve warning;
- Maximum generation emergency action;
- Emergency voluntary energy only demand response reductions;
- Voltage reduction warning and reduction of non-critical plant load;
- Curtailment of non-essential business load;
- Deploy all resources action;
- Manual load dump warning;
- Voltage reduction action;
- Manual load dump action; or
- Load shed directive.

Performance Assessment Intervals are in effect only for the specific area within PJM for which one of the above-listed emergency conditions was declared.

Q: What is Capacity Performance Insurance?

A: I&M witness Andrew Williamson describes Capacity Performance Insurance as covering "the final risk associated with PJM Capacity Performance rules."[27] He continues, "[t]he Capacity Performance Insurance for I&M's generation fleet will reimburse the Company (and ultimately customers) for Capacity Performance fees should a forced outage occur during a Capacity Performance event."[28]

Q: Has I&M estimated the premiums for this insurance?

A: Yes. I&M witness Toby Thomas states the annual premium is approximately $1.5 million.[29]

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[27] Direct Testimony of Andrew Williamson, p. 32, lines 5 – 6. It's not clear what Mr. Williamson means by "final risk". I suspect that he means "financial risk".
[28] *Id.*, lines 14 – 17.
[29] Direct Testimony of Toby Thomas, p. 34, lines 3 – 4.

Q: Has I&M requested recovery of the cost associated with Capacity Performance Insurance?

A: Yes, it has. Specifically, I&M proposed recovery of Capacity Performance Insurance through its OSS/PJM Rider.[30]

Q: Does I&M explain why it should be allowed to recover the cost of Capacity Performance Insurance?

A: Yes. Mr. Thomas states:

> It is appropriate to include this reasonable and necessary cost of providing service as a member of PJM in the PJM Rider.[31]
>
> Given the annual cost of insurance of approximately $1.5 million is a fraction of the cost of a Non-Performance Charge for a large unit, and multiple PAIs can be assessed in a given year (multiple events per year), I&M insures this risk to protect our customers and the Company. Therefore, this reasonable and necessary cost of being a member in PJM should be recovered through the PJM Rider.[32]

Q: Is appropriate for I&M to recover the costs of Capacity Performance Insurance?

A: No. I&M refers to the cost as necessary, but it is in fact discretionary. Implicit in Mr. Thomas' statement that "I&M insures this risk to protect our customers and the Company" is the assumption that any penalties would be paid by customers. No such assumption should be made. I&M's recovery of any penalty from customers should depend on the specific facts leading to the penalty. Moreover, Mr. Thomas concedes that the insurance benefits I&M. Customers should not have to pay for a benefit I&M receives. With respect to Mr. Thomas' claim regarding the possible size of the penalty, there is no evidence offered by I&M witnesses to support this. Finally, I&M refers generally to the risk against which it is insuring. While it isn't possible to statistically

[30] Direct Testimony of Andrew Williamson, p. 51, lines 9 – 11.
[31] Direct Testimony of Toby Thomas, p. 33, lines 22 – 23.
[32] *Id.*, p. 35, lines 3 – 8.

quantify the risk precisely, there are qualitative factors I&M ignores that act to limit the risk of being assessed non-performance penalties or that allow it to mitigate the impact if it is assessed a non-performance penalty. I provide more detailed information on my assessment of the risk of a PAI being called, which is rare and could become even more unlikely, and steps I&M has available to it to mitigate any penalty in Appendix C.

Q: If the Commission does allow recovery of Capacity Performance Insurance premiums, is it appropriate to allow such recovery through the OSS/PJM Rider tracker mechanism?

A: No. Earlier in my testimony, I discussed the Commission's previously expressed three (3) considerations when determining whether to approve tracker recovery of expenses: (1) collectively and potentially significant; (2) potentially variable or volatile; and (3) largely outside the utility's control. While I&M has not discussed Capacity Performance Insurance premiums in the context of those considerations, Mr. Thomas has estimated an annual cost of $1.5 million, with no mention of variability or potential increase. Therefore, the Capacity Performance Insurance appears to fail the first and second factors above, and therefore does not qualify for tracker treatment.

V. <u>CAPACITY PERFORMANCE INSURANCE RECOMMENDATION</u>

Q: What is your recommendation relating to Capacity Performance Insurance?

A: I recommend that the Commission deny I&M's request to recover costs associated with Capacity Performance Insurance. I&M's O&M Adjustment 6 to the forecasted Test Year shows a Total Company miscellaneous expense for Capacity Performance Insurance of $1,513,220, which I recommend the Commission reject for the reasons described above.

Q: Should your testimony be interpreted such that you are recommending I&M not buy the insurance?

A: No, it should not. If I&M thinks purchasing such insurance is prudent, it should do so, but at the shareholders expense. Through my testimony, I am recommending the Commission deny I&M recovery of the expense from ratepayers, because I&M has not demonstrated that it is prudent.

VI. CONCLUSION AND RECOMMENDATIONS

Q: What are your recommendations to the Commission?

A: I recommend the Commission reject I&M's request to recover NITS Charges through the OSS/PJM Rider and include the estimated Test Year level of I&M's NITS Charges in base rates – subject to a compliance filing through which base rates are adjusted downward if I&M's actual NITS Charges are lower than the estimated level.

Q: What are your recommendations to the Commission relating to your concern over the magnitude and growth of NITS Charges?

A: I recommend that the Commission open an investigation to ensure that transmission investments that wind up in I&M's electric rates are prudent, given the lack of effective oversight over the planning of Supplemental Projects that result in NITS Charges to I&M. The Commission should explore the potential to (1) assess the prudency of Supplemental Projects built in Indiana and (2) shield I&M's electric customers from the costs of Supplemental Projects built outside of Indiana, but in the AEP East zone.

Q: What is your recommendation relating to Capacity Performance Insurance?

A: I recommend that the Commission deny I&M's request to recover costs associated with Capacity Performance Insurance in rates. I&M's O&M Adjustment 6 to the forecasted Test Year shows a Total Company miscellaneous expense for Capacity Performance

Insurance of $1,513,220, which, for the reasons described in my testimony, I recommend the Commission reject.

Q: Does this conclude your testimony?

A: Yes it does.

APPENDIX A: QUALIFICATIONS OF MIKE GAHIMER

Q: Please describe your educational background and experience.

A: I received a Bachelor of Science Degree in Mechanical Engineering from Purdue University at the West Lafayette, Indiana campus. After 6 years working in non-energy roles (Software Developer, Structural Designer) for an Architectural and Engineering firm, I began my 27 year-long energy career – starting at the OUCC in 1992. In my first stint with the OUCC, I held various roles with responsibility primarily for filings by natural gas and electric utilities at the Indiana Utility Regulatory Commission (IURC) and the Federal Energy Regulatory Commission (FERC). In 1995, I left the OUCC for employment at the Northern Indiana Public Service Company (NIPSCO). There I held various roles. Initially, I managed NIPSCO's participation in FERC dockets initiated by filings from any of the six (6) interstate natural gas pipeline's that served NIPSCO. Later, I took on Profit and Loss responsibility for NIPSCO's Fixed and Capped Price natural gas sales. In 2001, I left NIPSCO to develop and lead the energy management program for Duke Realty Corporation (DRC). Duke was, at the time, the largest mixed-use Real Estate Investment Trust (REIT) in the country – developing, owning and managing office, medical office, retail and warehouse facilities in more than 20 markets across the United States. While at DRC, I was responsible for all demand- and supply-side energy initiatives, in part, working on issues involving utilities, state utility regulatory Commissions and FERC as well as local, state and federal legislatures. In 2017, I returned to the OUCC in my current role. In my current role, I am exclusively focused on RTO issues in both at MISO and PJM.

APPENDIX B: THE M-3 PROCESS

Q: Would you provide more details regarding the M-3 Process – including TO's and stakeholder's involvement in it?

A: Yes. The M-3 Process includes a series of steps that must be completed before a TO can submit a Supplemental Project to PJM for inclusion in PJM's RTEP: (1) review of proposed assumptions and methodology; (2) review of Needs; (3) review of proposed and potential solutions; and (4) submission of the Supplemental Project. OATT Attachment M-3 lists, for each of the four (4) steps (1) what TOs "shall" do, (2) what stakeholders "may" do and (3) what TOs "may" do.[33]

Q: Please explain the first step: review of proposed assumptions and methodology.

A: Under the M-3 Process, there is to be at least one (1) meeting[34] of each Sub-Regional RTEP Committee during which each TO with facilities in that Sub-Region *shall* review with Stakeholders the criteria, assumptions and models on which it *proposes* to rely ("Assumptions") to identify Needs and develop Supplemental Project to satisfy those Needs ("Assumptions Meeting"). The information to be reviewed during the Assumptions Meeting is to be posted at least twenty (20) days before the Assumptions Meeting. Stakeholders *may* provide comments either before or after the Assumptions Meeting. Each TO *shall* review and consider any comments that are received within ten (10) days of the Assumption Meeting. It *may* respond to, or provide feedback on, the comments.

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[33] OATT Attachment M-3 included in Attachment MG-3.

[34] OATT Attachment M-3 is silent as to the time period in which "one" meeting is to occur. It could be interpreted as one ever, one per planning cycle or any other time period.

Q: Please explain the second step: review of Needs.

A: There is to be at least one (1) meeting of each Sub-Regional RTEP committee per planning cycle during which each TO with facilities in that Sub-Region *shall* review with stakeholders, in the context of the Assumptions it reviewed in the Assumptions Meeting, any identified Need that may result in a Supplemental Project ("Needs Meeting"). No Needs Meeting can be convened any sooner than twenty five (25) days after the corresponding TO's Assumptions Meeting. The information to be reviewed during the Needs Meeting is to be posted at least ten (10) days before the Needs Meeting. Each TO *shall* review and consider any comments that are received within ten (10) days of the Assumption Meeting. It *may* respond to, or provide feedback on, the comments.

Q: Please explain the third step: review of potential solutions.

A: There is to be at least one (1) meeting of each Sub-Regional RTEP committee per planning cycle during which each TO with facilities in that Sub-Region *shall* review with stakeholders potential solutions, and any alternative solutions the TO considered, that would satisfy the Needs identified in a Needs Meeting ("Solutions Meeting"). No Solutions Meeting can be convened sooner than twenty five (25) days after the corresponding TO's Needs Meeting. The information to be reviewed during the Solutions Meeting is to be posted at least ten (10) days before the Solutions Meeting. Each TO *shall* review and consider any comments that are received within ten (10) days of the Solutions Meeting. It *may* respond to, or provide feedback on, the comments.

Q: Please explain the fourth step: submission of the Supplemental Project.

A: TO's submit to PJM any Supplemental Projects they intend to build after having taken them through the M-3 Process. Stakeholders *may* provide comments on the Supplemental Projects before PJM integrates them into the RTEP. TOs *shall* review and consider comments that are received at least 10 days before the Supplemental Project is submitted for inclusion in the RTEP.

Q: What is the significance of submitting a Supplemental Project to PJM for inclusion in the RTEP?

A: Once a Supplemental Project is submitted to PJM for inclusion in the RTEP, it is added to the base case in the next RTEP model build. The base case model is used by PJM for a number of purposes: identifying Baseline Needs; testing proposed solutions; running sensitivity analysis; etc. Once a Supplemental Project is added to the base case model, it "becomes" a part of the grid topology unless and until PJM is notified that the Supplemental Project will not be built or will be delayed. Therefore, that Supplemental Project affects every transmission-related decision made after it is added to the model, such as decisions regarding Needs, solutions to Needs and applications in the Interconnect Queue to name a few.

Q: You used the word "proposed" to describe the Assumptions that are presented in the Assumptions meeting and the word "potential" to describe the solutions that are presented in a Solutions Meeting. Would you please explain why?

A: Those are the words used in Attachment M-3. While they imply that stakeholder input is being accepted and considered before decisions are made, in my experience, stakeholder input is rarely accepted.

Q: Why did you emphasize the words "shall" and "may"?

A: To emphasize the point that while TOs have to review and consider comments, they have no obligation to respond to them. If they choose not to make any changes or take any different action because of the comments, they do not have to explain why. For that matter, TOs are not required to indicate that the comments had no effect on their plans.

Q: Do you participate in the M-3 Process?

A: Yes, I attend PJM's TEAC and Western Sub-Regional RTEP meetings on behalf of the OUCC.

Q: In the Sub-Regional RTEP Committee meetings, have you witnessed any changes being made to Assumptions or Solutions in response to stakeholder feedback?

A: No, I have not.

Q: Does any non-I&M entity perform project prudency reviews as part of the M-3 Process?

A: No.

Q: Is there an opportunity for consumer advocates such as the OUCC to object to projects during the M-3 process?

A: While it is possible for consumer advocates such as the OUCC to raise concerns in any of the four (4) steps of the M-3 Process in theory, it isn't practicable. First, the M-3 Process explicitly gives stakeholders the right to provide comments, but *not* the right to ask questions. Second, the M-3 process doesn't explicitly require a TO to respond to any comment. With no explicit stakeholder right to ask questions and no explicit requirement for TOs to respond to comments, stakeholders do not have, in practice, any opportunity to object to projects. This is not to suggest that TOs do not answer questions and respond to comments - they do.[35] But it is not clear that comments have any effect. The reality is that the M-3 process includes multiple hurdles, each of which are tough to clear. Very little information is provided about (1) the Needs, (2) the Supplemental Project developed to satisfy those Needs and (3) the alternatives that were considered. Added to short planning timeframes (projects can progress from Needs identification through project submission in as few as 25 days), those hurdles, individually and collectively, make it impossible to assess and ensure the appropriateness of Supplemental Projects that are presented. Through the M-3 Planning process, TOs plan Supplemental Projects that in many cases represent investments in the tens of millions of dollars. In a process that gives stakeholders no right to compel the provision of adequate information to understand the Needs or Solutions (either up front or during the process in response to questions or comments), stakeholders have as few as twenty-five (25) days to try to understand the Need, assess the propriety of the Solution and develop any alternatives to it. Contrary to Mr. Ali's claim, the M-3 Process does not ensure "that Owner Projects that are incorporated into the RTEP are appropriate, efficient, and cost-effective solutions to planning criteria and system needs that benefit customers."[36]

Q: What is a "no harm" analysis?

A: In a "no harm" analysis, PJM reviews each Supplemental Project to determine whether it would create one or more Baseline criteria violations if built. If a Supplemental

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[35] Stakeholders have asked PJM to develop the ability to report the percentage of questions that are answered or the percentage of comments that receive responses. At this point, PJM has stated that it plans to do so, but such information is not currently available.

[36] Direct Testimony of Kamran Ali, p. 21, lines 12 - 14.

Project would trigger a Baseline criteria violation, the TO must modify the Supplemental Project to avoid the criteria violation if it chooses to build the Supplemental Project.

Q: Does PJM's "no harm" analysis assess the prudence of a Supplemental Project?

A: No. In its "no harm" analysis, PJM does not assess whether a Supplemental Project is prudent as Commissions would do in certificate of Public Convenience and Necessity ("CPCN") proceedings. PJM does not confirm the Need for the Supplemental Project. PJM does not validate the estimated cost of the Supplemental Project. PJM does not explore whether there are superior alternatives to the Supplemental Project. It only ensures that the Supplemental Project would not trigger a Baseline Need.

Q: What types of projects has I&M reviewed with the TEAC and Sub-Regional RTEP Committees so far this year?

A: I&M's Supplemental Projects include replacement of conductors, rebuilding or replacement of substations, and replacement of poles and wire. Some of the project descriptions are identical to those in I&M Witness David Isaacson's testimony, which is offered in support of I&M's proposed distribution projects. OUCC Witness Anthony Alvarez addresses the distribution projects in detail.

Q: How is PJM involved in Supplemental Projects?

A: PJM's involvement in Supplemental Project planning is limited to the "M-3 Process" pursuant to Attachment M-3 of PJM's OATT, which I have attached as Attachment MG-3. Under that process, a TO must review Supplemental Needs, and Supplemental Projects it has chosen to satisfy those Needs, with stakeholders in PJM's TEAC or the appropriate Sub-Regional RTEP Committee ("Sub-Regional"). PJM facilitates the TEAC and Sub-Regional meetings at which the TOs present the Supplemental Projects to stakeholders. Even after taking a Supplemental Project through the M-3 Process, the TO is still not required by PJM to build it. However, if the TO does still plan on building the Supplemental Project, the TO must submit it to PJM. PJM performs a "no harm" analysis on each Supplemental Project that is submitted to ensure it does not create Baseline Needs. Finally, PJM adds submitted Supplemental Projects to the RTEP.

Q: Are CPCNs or siting approvals from a relevant regulatory authority required for a Supplemental Project?

A: There are no federal CPCN requirements or siting approval requirements, and state and local requirements vary across PJM's footprint. It is my understanding that in Indiana, a TO is not required to secure a CPCN from the Commission unless it is seeking recovery of federally mandated costs.

APPENDIX C: CAPACITY PERFORMANCE RISK ASSESSMENT

Q: Please discuss the capacity performance insurance risk.

A: The risk associated with Capacity Performance can be thought of as a series of waterfalls over which less water flows at each successive level. At the bottom, there may not be much water falling at all. The first level is the risk of a PAI occurring. The second level is the PAI occurring in a sub-area of PJM that would involve I&M. The third level is the risk that the underlying cause of the PAI was one in which generation was implicated. The fourth level is the risk that I&M generation would be experiencing a forced outage during such PAI. The likely amount of water falling at the bottom can be put in perspective by a review of past PAIs.

Q: How many PAIs have occurred in the past and what was their nature?

A: In Section 3 (Energy Market) of its Quarterly State of the Market Reports, PJM's Independent Market Monitor ("IMM") lists the PAIs that have occurred in the past.[37] PJM also reports PAIs to the Operating Committee ("OC"). I have attached two OC reports as Attachments MG-5 and MG-6. Since the inception of Capacity Performance, there have only been two (2) events that resulted in PAIs – both in very localized areas of the AEP East Zone, both related to transmission outages such that no generation was implicated and, therefore, neither resulting the assessment of Penalties/Bonus Credits. One of the events lasted for five of PJM's five-minute settlement periods. The other lasted for twenty of PJM's five-minute settlement periods. To provide some perspective, consider that there were 315,360 five-minute intervals in first three years

[37] http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019.shtml

of Capacity Performance (ignoring leap years).[38] Out of 315,360 settlement periods, there were only twenty-five during which PAIs occurred and none during which Penalties and Bonus Credits were assessed.

Q: Are there future factors that might make PAIs even rarer?

A: If FERC approves anything like PJM's Operating Reserve proposal,[39] PJM will begin buying an unprecedented level of reserves at potentially unprecedented prices. Under PJM's proposal, the current two-step Operating Reserve Demand Curve ("ORDC") under which "demand" drops to zero at a particular level of reserves with a downward sloping ORDC that never reaches a zero level of reserves. In addition, under PJM's proposal the maximum allowable offer price for reserves would increase from $3,700 per Mwh to $14,000 per Mwh (both under the worst case scenario). This will likely dramatically increase the amount of reserves procured – further decreasing the likelihood of PAIs.

Q: Please discuss impact mitigation.

A: There are three factors that could serve to mitigate the impact of any Penalty assessment. First, any Bonus Credits received during PAIs would offset any Penalties received during different PAIs.[40] Second, as an FRR elector, I&M has a choice non-FRR electors don't have. It can choose to provide "substituted energy" rather than pay the financial Penalty. It is possible it would be less expensive to cover the Performance Shortfall with substituted generation than to pay the Penalty. Third, Capacity

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[38] There are 12 five-minute intervals per hour, 24 hours per day, 365 days per year, 3 years of Capacity Performance (12X24X365X3=315,360).
[39] Docket Nos. EL19-58-000 and EL19-1486.
[40] In making that statement, I don't mean to imply that it is likely PAIs will occur, let alone multiple PAIs, in a given year. As I've discussed, PAIs have rarely occurred in the past.

Performance includes a Stop Loss provision that places a ceiling on the total amount of Penalties that can be levied against a generation resource. While the Stop Loss level is potentially high, the possible financial impact isn’t unlimited.

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Michael S. Gahimer

Michael Gahimer
Senior Utility Analyst
Indiana Office of Utility Consumer Counselor

Cause No. 45235
Indiana Michigan Power Company

August 19, 2019
Date

Indiana Michigan Power Company
Annual Report Pursuant to Section I.A.3.f of the Stipulation and Settlement Agreement in Cause No. 44976
November 2018

Projection of I&M and I&M Transco NITS Capital Projects Expected to Be Started in 2019

Project Identifying Number	AEP Entity Responsible for the Project	Project Location	Project Description	Actual or Projected Construction Start Date	Projected Capitalized Cost*	Projected In-Service Date	Projected Project Category
MP0004117	I&M Transco	IN	Central South Bend Reliability Project	3/26/2019	$ 30,288,760	9/17/2020	Supplemental
MP0004255	I&M Transco	IN	Kenmore - New Service to Ball State	5/13/2019	$ 4,127,489	11/7/2019	Supplemental
MP0004433	I&M Transco	IN	SDI	5/24/2019	$ 65,960,687	5/29/2020	Baseline
MP0006371	I&M Transco	MI	Niles Area Reinforcements	12/13/2019	$ 32,690,250	12/30/2020	Supplemental/Baseline
MP0006387	I&M Transco	IN	Anthony-Lakeside 34.5 kV Rebuild	7/1/2019	$ 6,230,100	9/23/2020	Supplemental
MP0006393	I&M	IN/MI	Dumont – Cook 765 kV Spacer Replacement	6/3/2019	$ 1,088,787	10/18/2019	Non-topology
MP0010817	I&M Transco	IN	Grentown Asset Transfer	2/15/2019	$ 17,842,247	11/1/2019	Supplemental
MP0010821	I&M Transco	IN	Madison 34.5kV Rebuild	7/29/2019	$ 6,106,105	2/17/2020	Supplemental
MP1865075	I&M Transco	MI	Twin Branch - Benton Harbor 138 Kv Rebuild (Michigan side)	3/4/2019	$ 93,300,060	11/5/2021	Supplemental
MP1922957	I&M Transco	MI	Langley Tx replacements	10/14/2019	$ 711,390	3/31/2020	Supplemental
MP1922961	I&M Transco	IN	Wire Mill-Green field rebuild	8/5/2019	$ 1,157,882	11/22/2019	Supplemental
MP1922974	I&M	IN	I&M RTU Reliability Program	2/4/2019	$ 1,790,442	7/22/2019	Non-topology
MP1951838	I&M Transco	IN	Sullivan Physical Security	8/20/2019	$ 20,222,696	6/10/2021	Non-topology
MP1951840	I&M	IN	Fall Creek Physical Security	9/25/2019	$ 5,256,928	11/6/2020	Supplemental
MP1951841	I&M	IN	Robison Park Physical Security	8/20/2019	$ 5,323,920	6/10/2021	Non-topology
MP1951842	I&M	IN	Tanners Creek Physical Security	10/9/2019	$ 7,352,502	1/8/2021	Non-topology
MP1951843	I&M	IN	Olive Physical Security	1/29/2019	$ 8,341,812	10/5/2020	Non-topology
MP1951855	I&M Transco	IN	Sorenson Phasing Project	1/7/2019	$ 177,220	3/29/2019	Supplemental
MP1951858	I&M Transco	IN	North Clinton Laydown Yard	4/29/2019	$ 2,934,429	6/1/2019	Non-topology
MP1951863	I&M	IN	Dome Tap Line Relocation	10/18/2019	$ 1,569,348	11/27/2019	Supplemental
MP1951864	I&M	IN	South Bend-Dragoon Rplc & relo	8/15/2019	$ 372,023	9/19/2019	Supplemental
MP1958855	I&M	IN	Deer Creek 138kV TR 1	10/7/2019	$ 298,535	11/15/2019	Supplemental
MP1958856	I&M	IN	Illinois Road 138kV TR 1	11/25/2019	$ 280,774	1/13/2020	Supplemental
MP1958857	I&M	IN	Kendallville 138kv TR 3	10/9/2019	$ 303,852	11/27/2019	Supplemental
MP1958860	I&M	IN	Indalex Tap Line Replacement	5/28/2019	$ 380,163	7/12/2019	Supplemental
MP1958943	I&M	IN	Edison Relay Upgrade	2/2/2019	$ 1,744,851	5/10/2019	Supplemental
MP1958977	I&M	IN	Desoto Physical Security	9/3/2019	$ 5,342,982	12/31/2020	Supplemental

Aggregate Data Concerning Other NITS Capital Projects by AEP Operating Companies or Transcos in the AEP East Zone**

Total NITS projects projected to be started in 2019 in the AEP East Zone:	132

Total projected cash expenditures for projects starting in 2019 on all NITS capital projects in the AEP East Zone:	$ 841,015,020

**Data include I&M and I&M Transco

Project Statistics

Transmission Expansion Advisory Committee
January 10, 2019

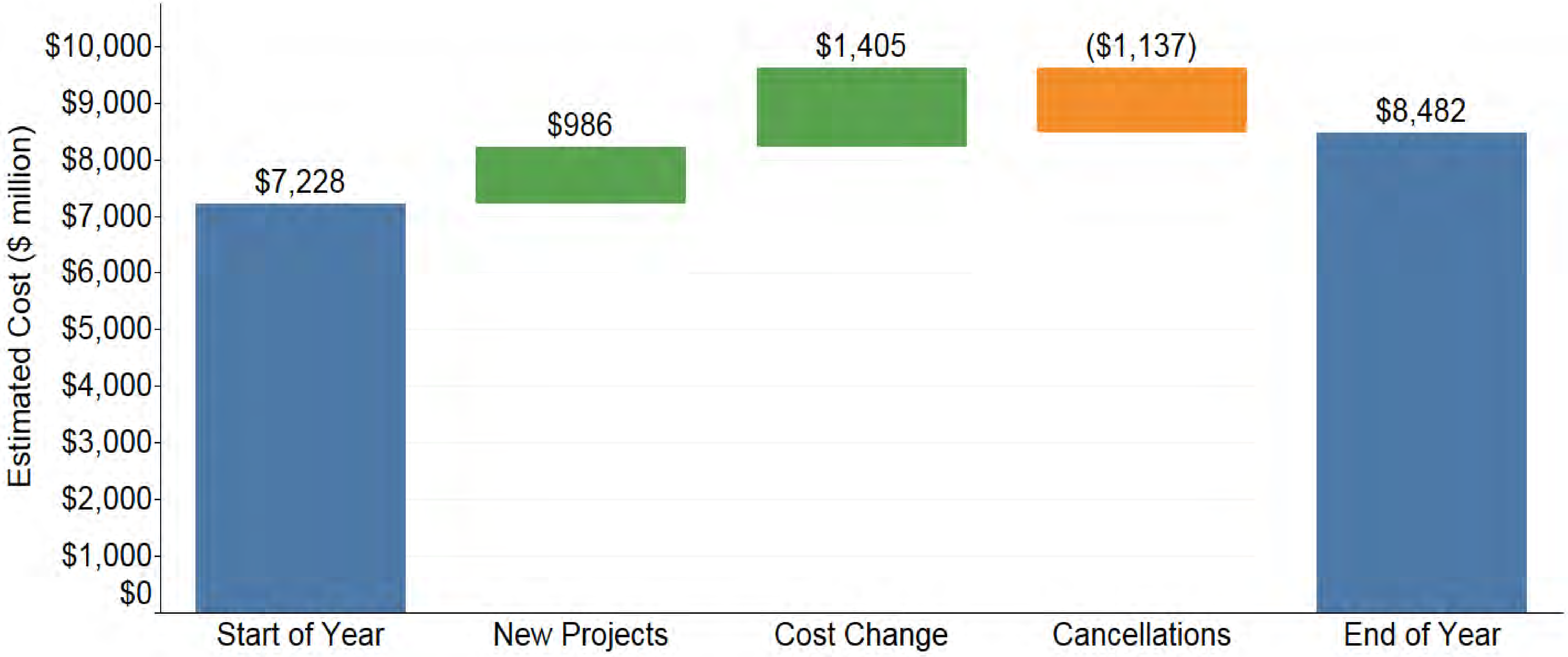
Overview

Each slide summarizes the estimated costs for projects presented at the TEAC or Sub-regional TEAC meetings.

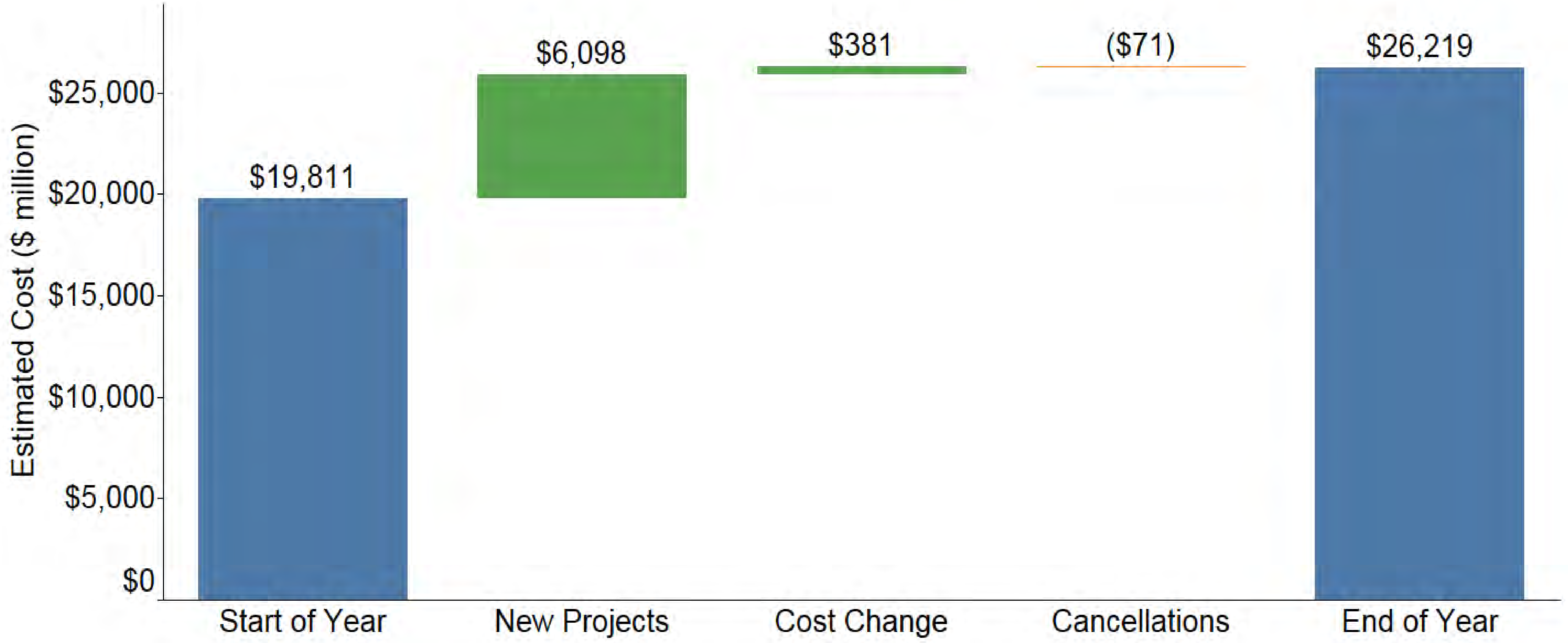
- Costs are provided by the Designated Entity or Transmission Owners. Cost estimation methods may vary by company. Estimated costs in this document may include cost caps or cost containment even though it isn't specifically noted
- Cost estimates may change over time as new information is known and incorporated into the estimate by the project sponsor, this document reflects the current estimates that are provided to PJM
- A single cost is provided for each project identifier, without any additional breakdown (for example, cost by state)

2018 Changes to the RTEP Baseline Projects

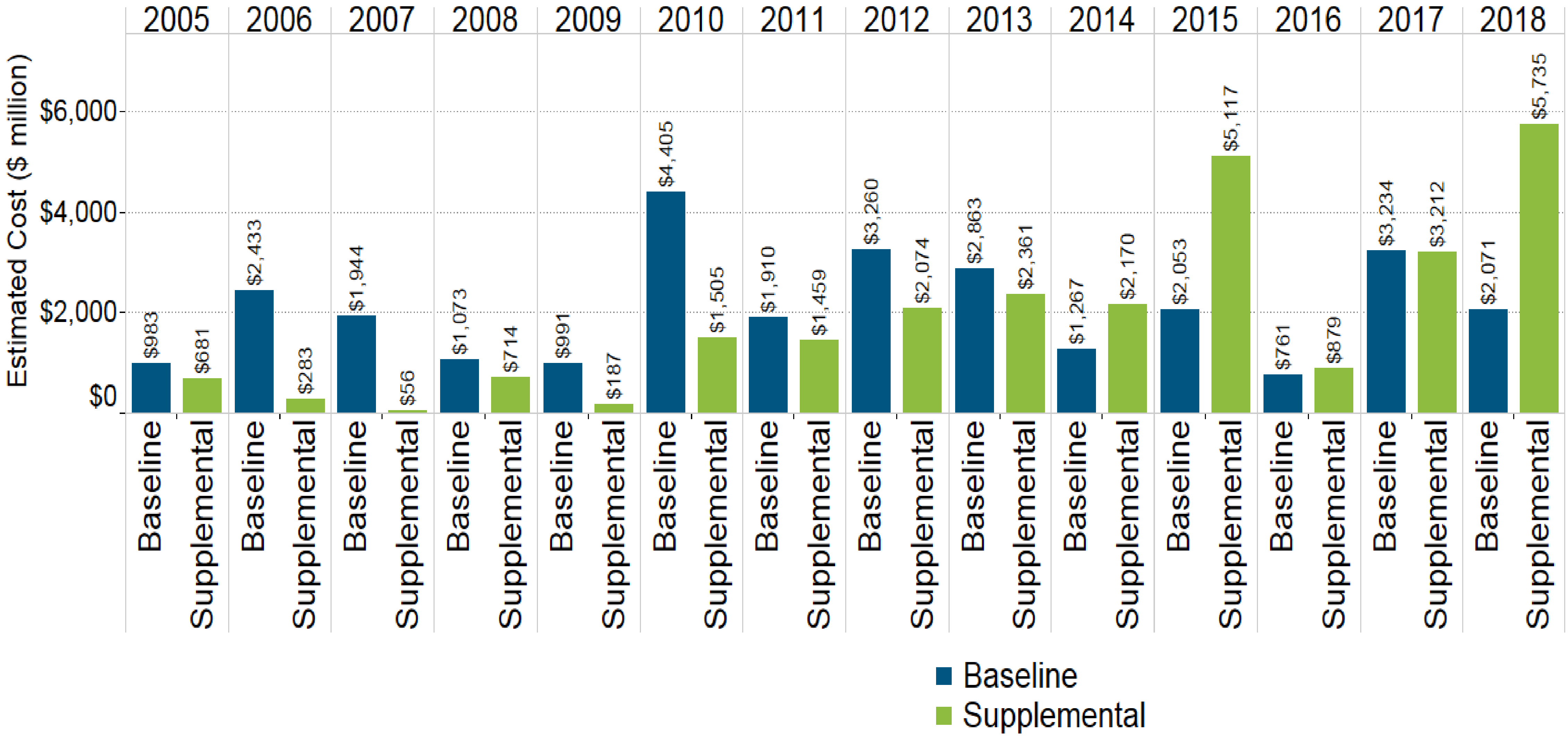
2018 Changes to the RTEP Generation and Merchant Network Upgrade Projects



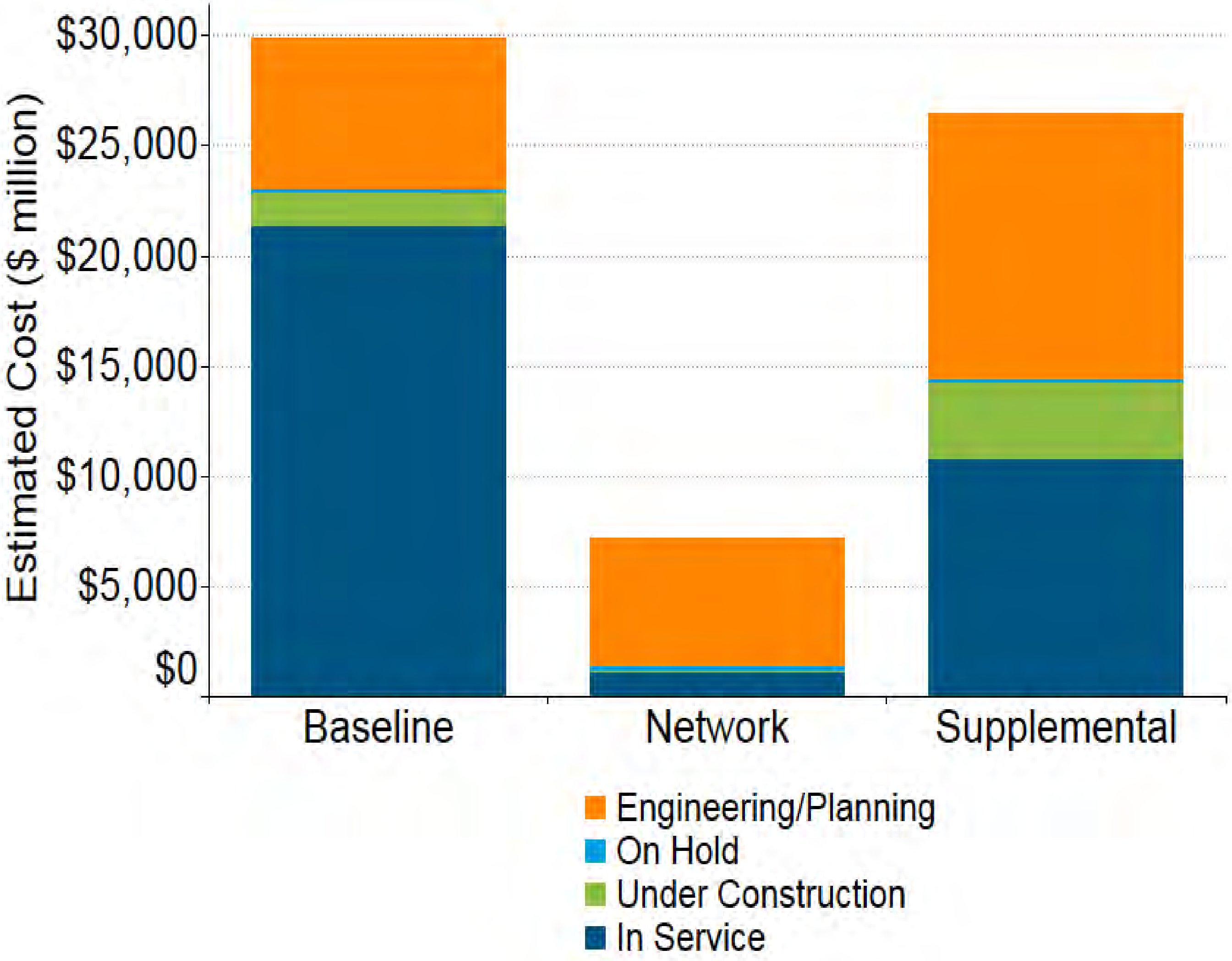
2018 Supplemental Projects Presented by TOs to TEAC/Sub-regional TEAC Meetings



New Baseline and Supplemental Projects by Year



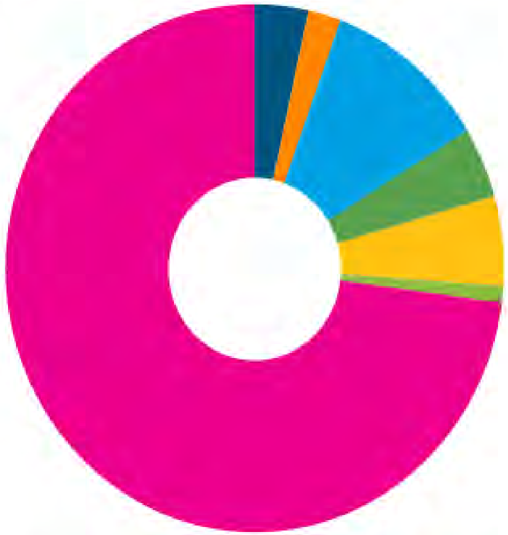
Project Status



	Baseline	Network	Supplemental
Engineering/Planning	$6,926	$5,800	$12,037
On Hold	$162	$208	$155
Under Construction	$1,494	$36	$3,541
In Service	$21,307	$1,133	$10,707
Grand Total	**$29,889**	**$7,177**	**$26,440**

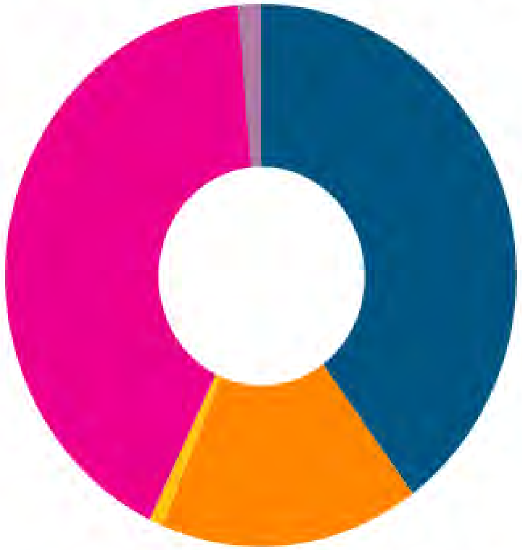
New Projects in 2018
Project Drivers

Estimated Cost of Baseline Projects Approved by PJM Board



Baseline Load Growth Deliverability & Reliability	$72
Congestion Relief - Economic	$44
Generator Deactivation	$221
Not Specified	$90
Operational Performance	$113
Short Circuit	$22
TO Criteria Violation	$1,509

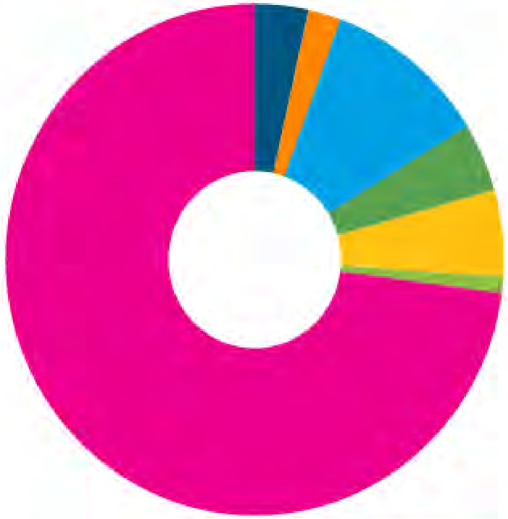
Estimated Cost of Supplemental Projects Presented by TOs to the TEAC



Equipment Material Condition, Performance and Risk	$2,287
Operational Flexibility and Efficiency	$942
Customer Service	$49
Other	$1
Multiple Drivers	$2,377
Null	$79

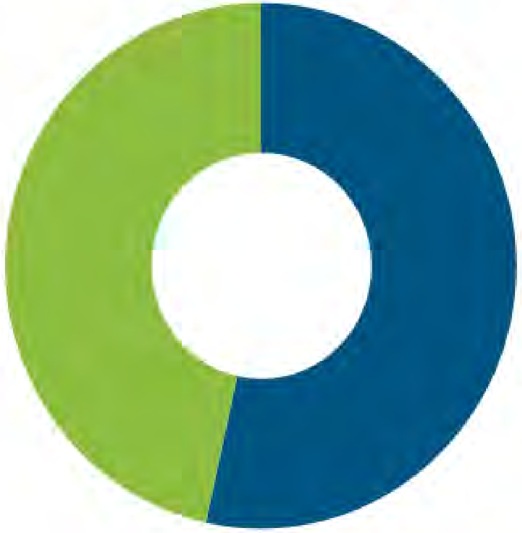
New Projects in 2018
Baseline Project Drivers

Estimated Cost of Baseline Projects Approved by PJM Board



Baseline Load Growth Deliverability & Reliability	$72
Congestion Relief - Economic	$44
Generator Deactivation	$221
Not Specified	$90
Operational Performance	$113
Short Circuit	$22
TO Criteria Violation	$1,509

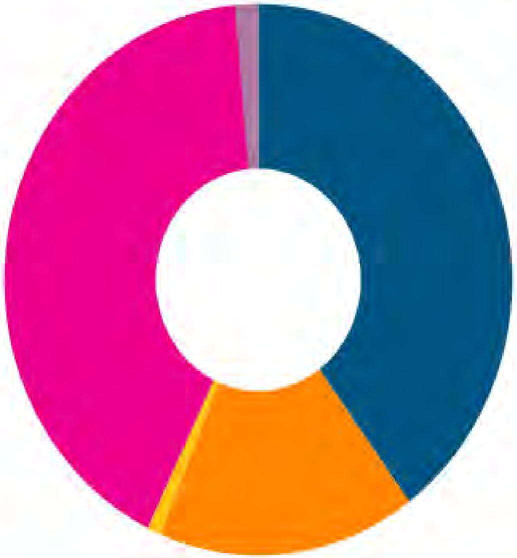
Estimated Cost of Baselines Projects Driven by TO Criteria Violations



Aging Infrastructure	$807
Other TO Criteria	$702

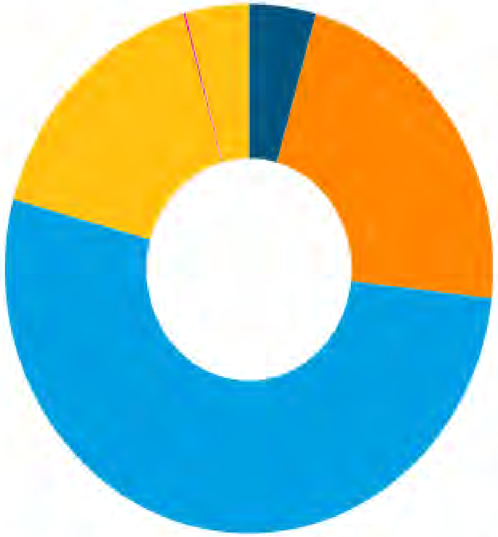
New Projects in 2018
Supplemental Project Drivers

Estimated Cost of Supplemental Projects Presented by TOs to the TEAC



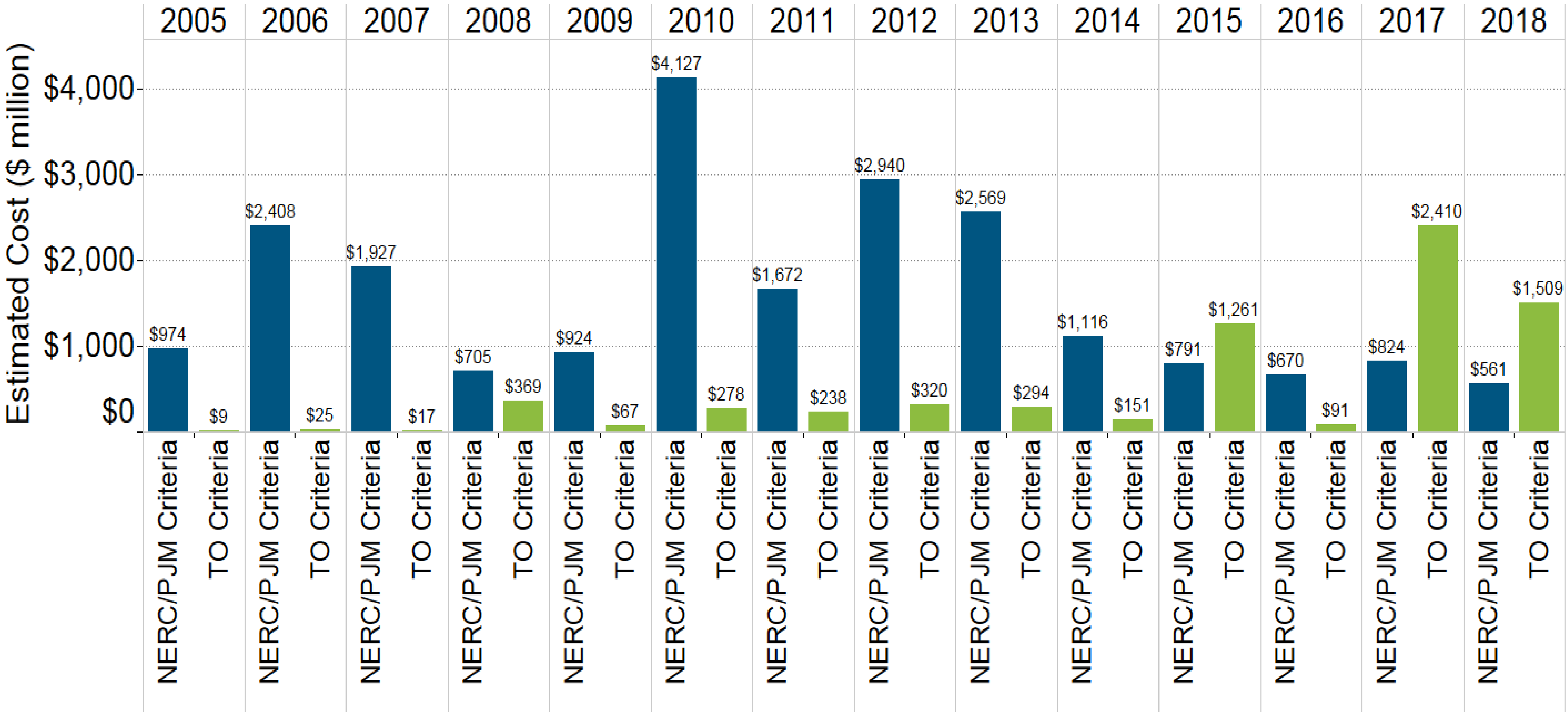
Equipment Material Condition, Performance and Risk	$2,287
Operational Flexibility and Efficiency	$942
Customer Service	$49
Other	$1
Multiple Drivers	$2,377
Null	$79

Estimated Cost of Supplemental Projects with Multiple Drivers

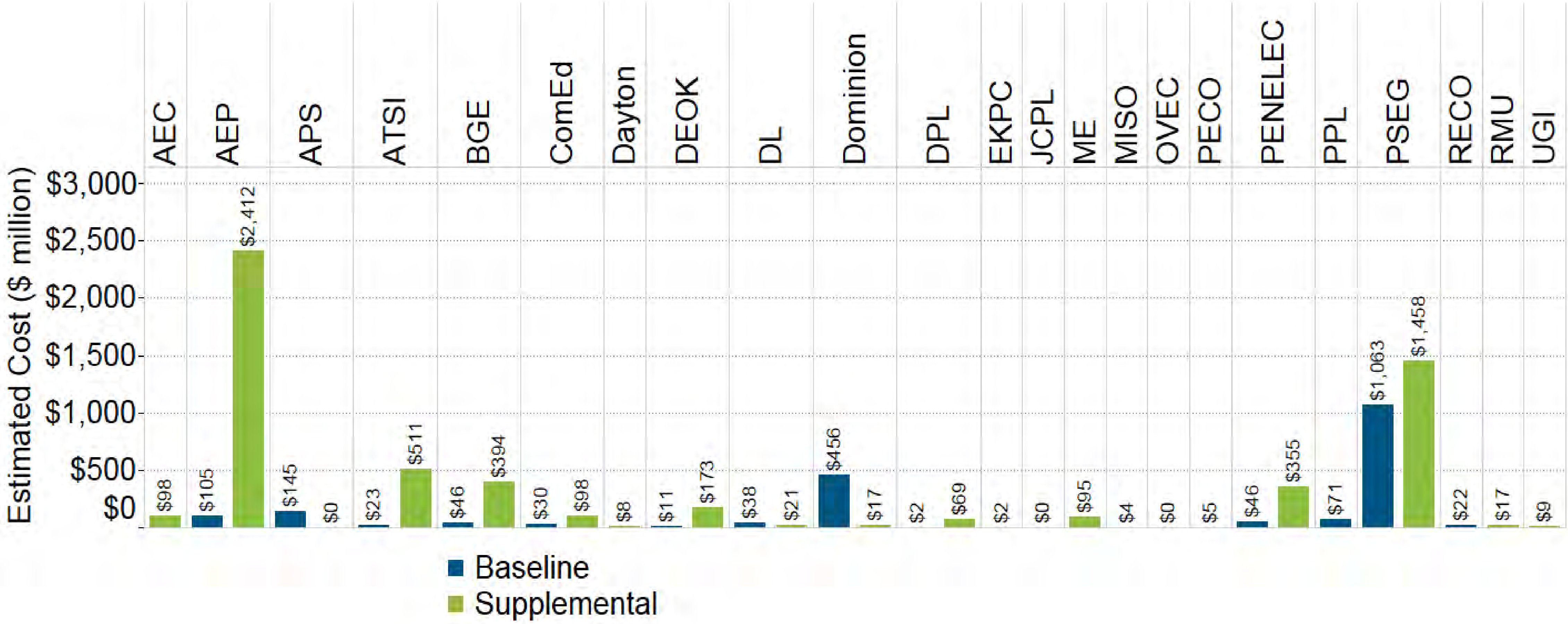


Equipment Material Condition, Performance and Risk / Customer Service	$105
Equipment Material Condition, Performance and Risk / Infrastructure Resilience	$532
Equipment Material Condition, Performance and Risk / Infrastructure Resilience / Customer Service	$0
Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency	$1,246
Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency / Custo..	$391
Equipment Material Condition, Performance and Risk / Operational Flexibility and Efficiency / Infrast..	$3
Operational Flexibility and Efficiency / Customer Service	$99

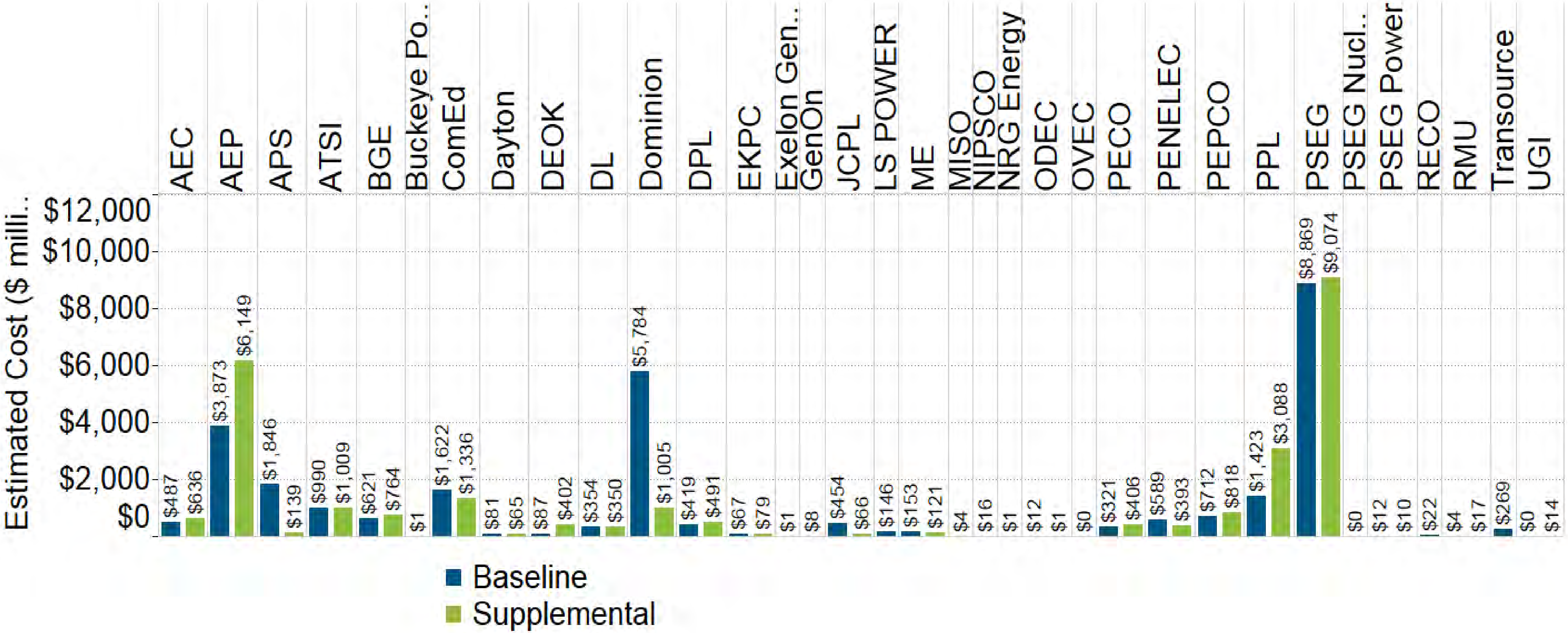
Baseline Project Driver Type



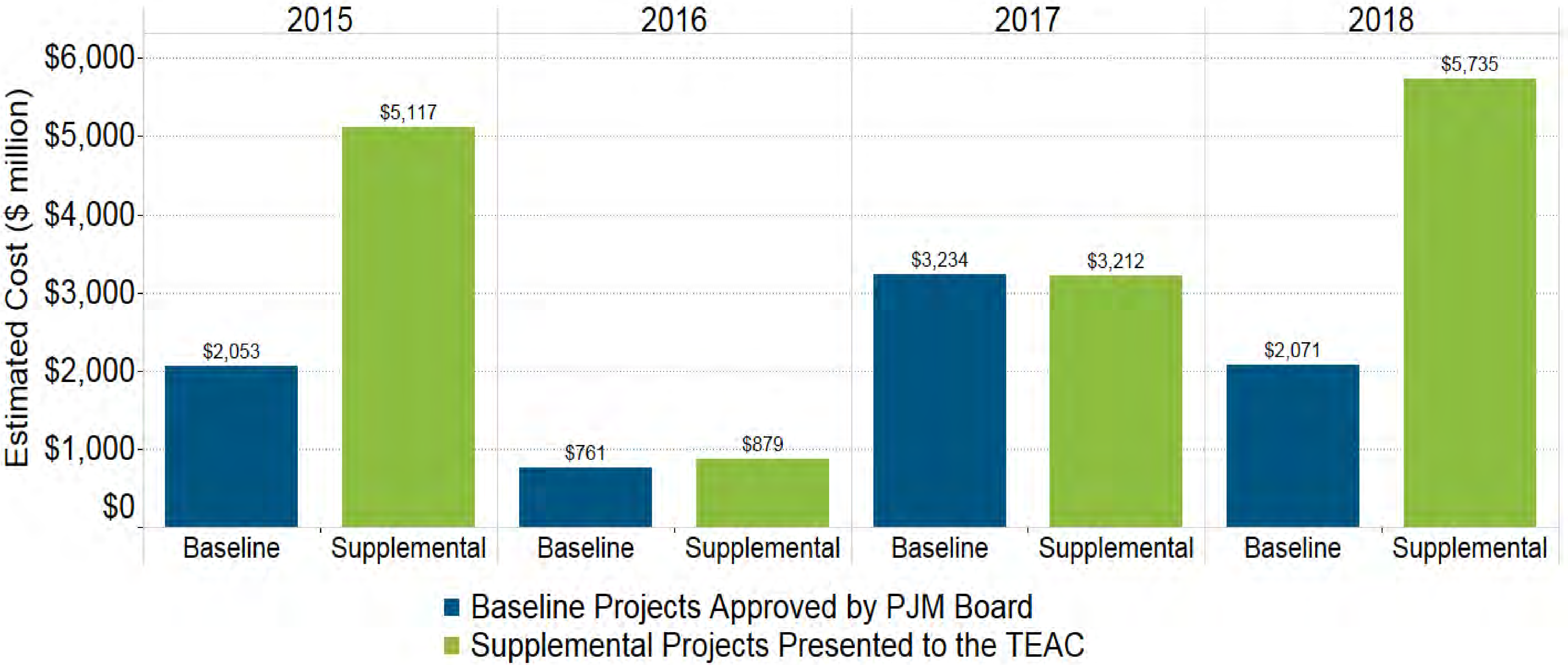
Distribution of New Baseline and Supplemental Projects Approved by the PJM Board (baseline) or Presented (supplemental) in 2018



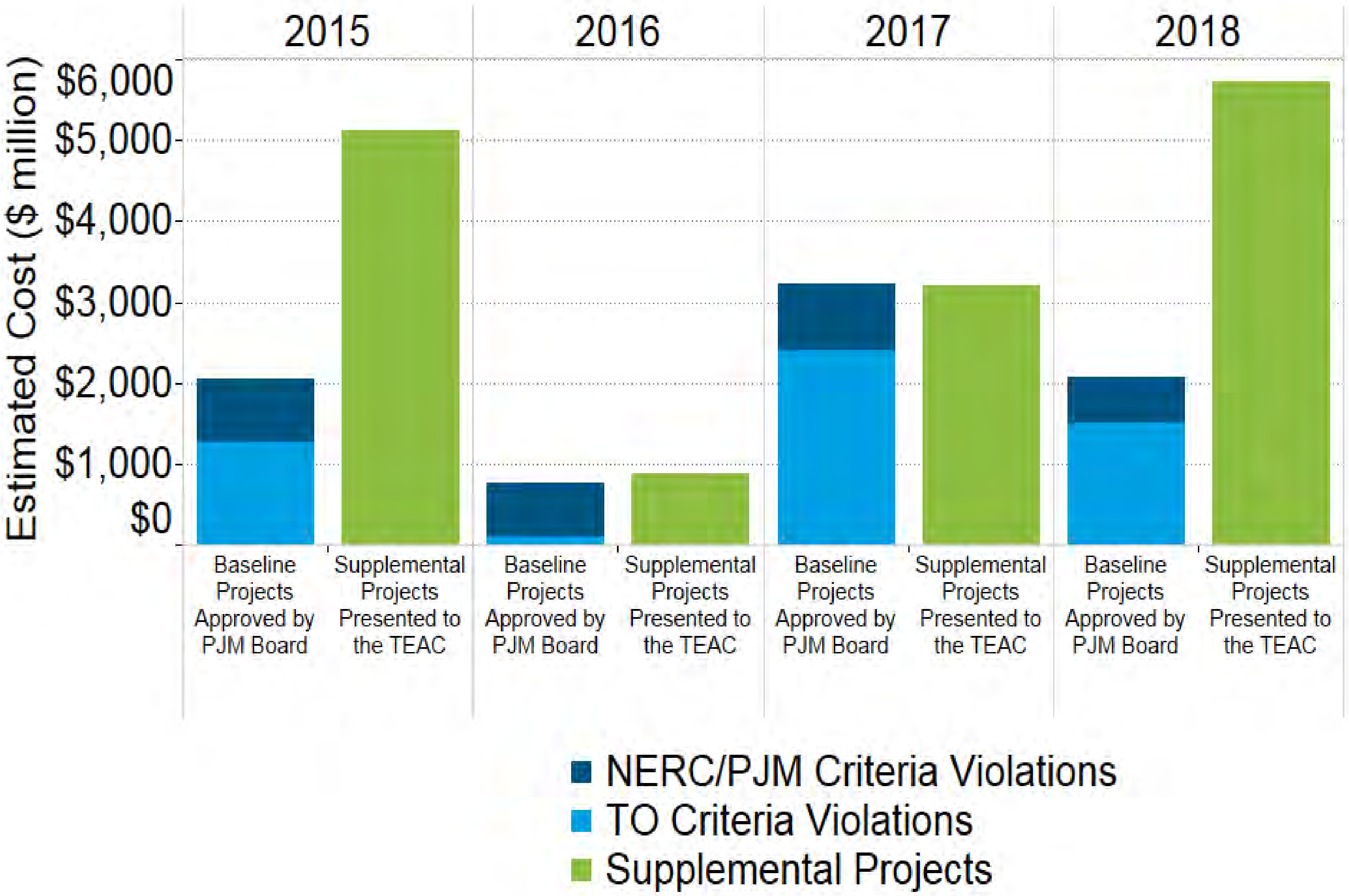
Distribution of New Baseline and Supplemental Projects Approved by the PJM Board (baseline) or Presented (supplemental) since 2005



Baseline and Supplemental Projects by Year

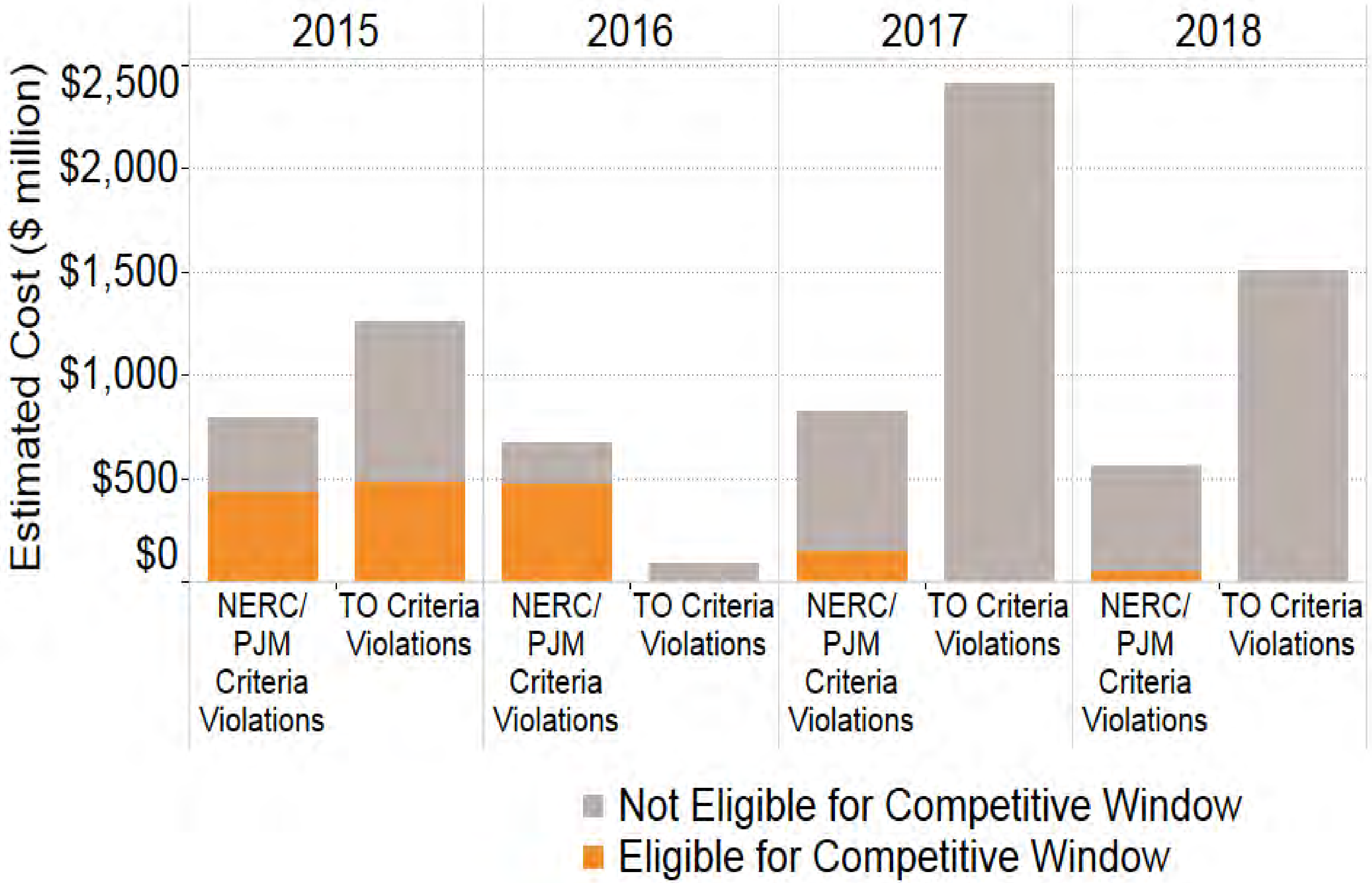


Baseline and Supplemental Projects by Year



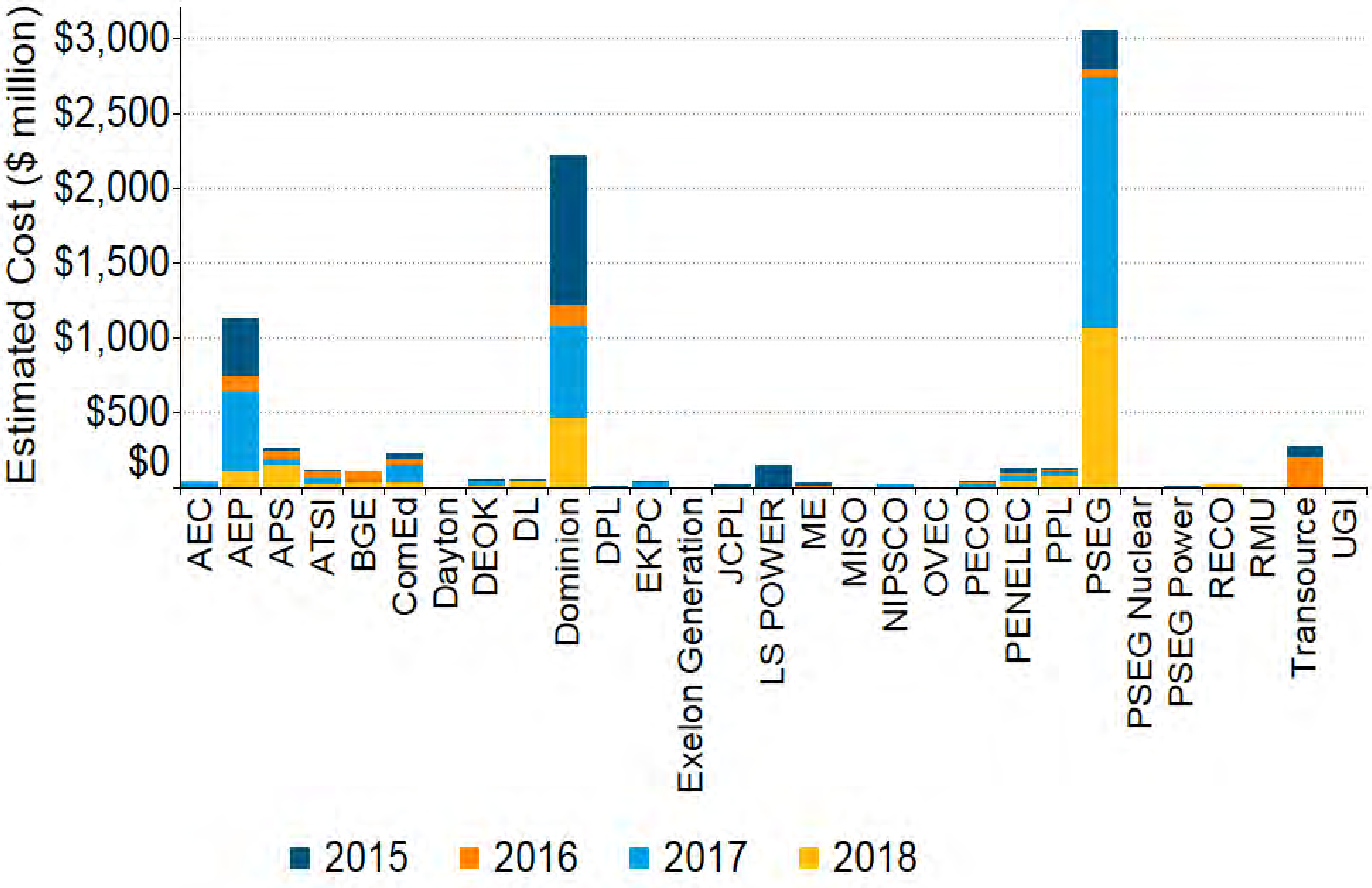
	Baseline		Supplemental
	NERC/PJM Criteria Violations	TO Criteria Violations	Supplemental Projects
2015	$791	$1,261	$5,117
2016	$670	$91	$879
2017	$824	$2,410	$3,212
2018	$561	$1,509	$5,735

Baseline Projects by Year



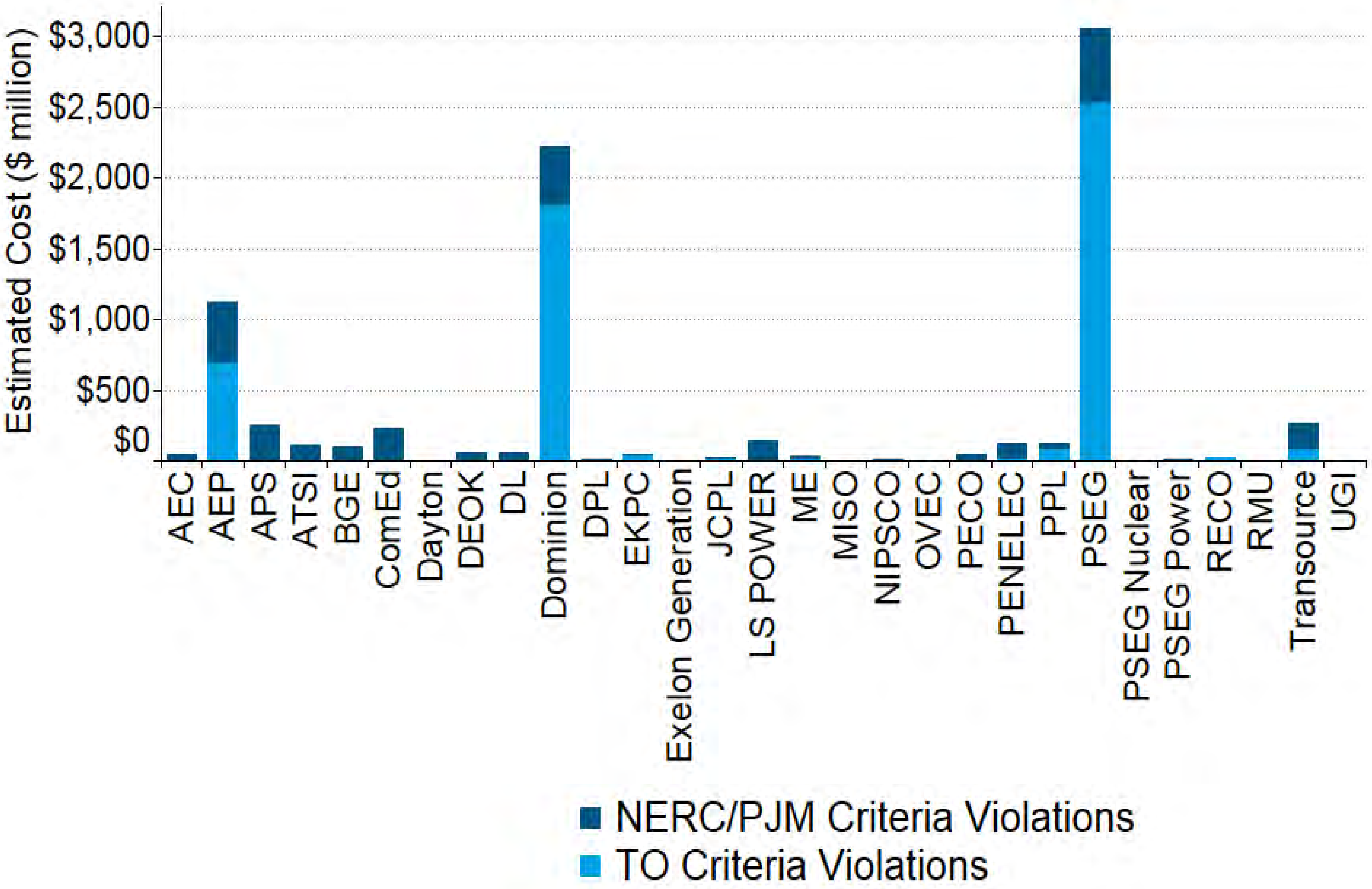
	Eligible for Competitive Window	Not Eligible for Competitive Window
2015	$912	$1,140
2016	$471	$290
2017	$142	$3,092
2018	$50	$2,020

Baseline Projects by Designated Entity Approved by PJM Board 2015-2018



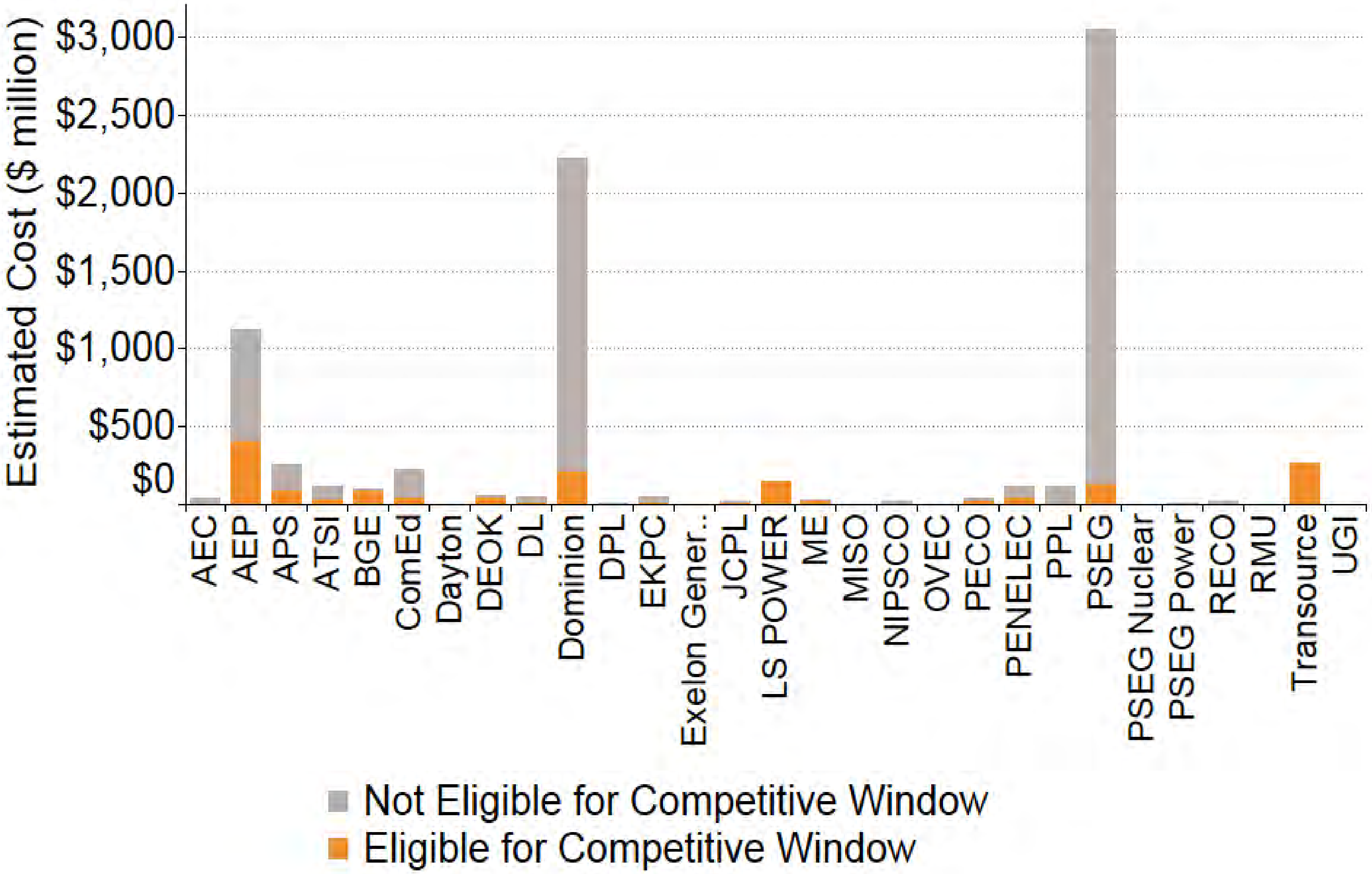
	2015	2016	2017	2018
AEC		$1	$37	
AEP	$381	$114	$526	$105
APS	$15	$60	$38	$145
ATSI	$12	$45	$35	$23
BGE		$53	$1	$46
ComEd	$40	$39	$116	$30
Dayton			$1	
DEOK	$7		$37	$11
DL	$13			$38
Dominion	$998	$148	$621	$456
DPL	$4		$3	$2
EKPC	$5	$1	$38	$2
Exelon Generation			$1	
JCPL	$23	$1	$0	$0
LS POWER	$146			
ME	$21	$3	$6	
MISO				$4
NIPSCO			$16	
OVEC				$0
PECO	$12	$12	$14	$5
PENELEC	$30	$15	$31	$46
PPL	$5	$14	$33	$71
PSEG	$260	$56	$1,679	$1,063
PSEG Nuclear	$0			
PSEG Power	$9			
RECO				$22
RMU		$4		
Transource	$72	$197		
UGI		$0		

Baseline Projects by Designated Entity Approved by PJM Board 2015 - 2018



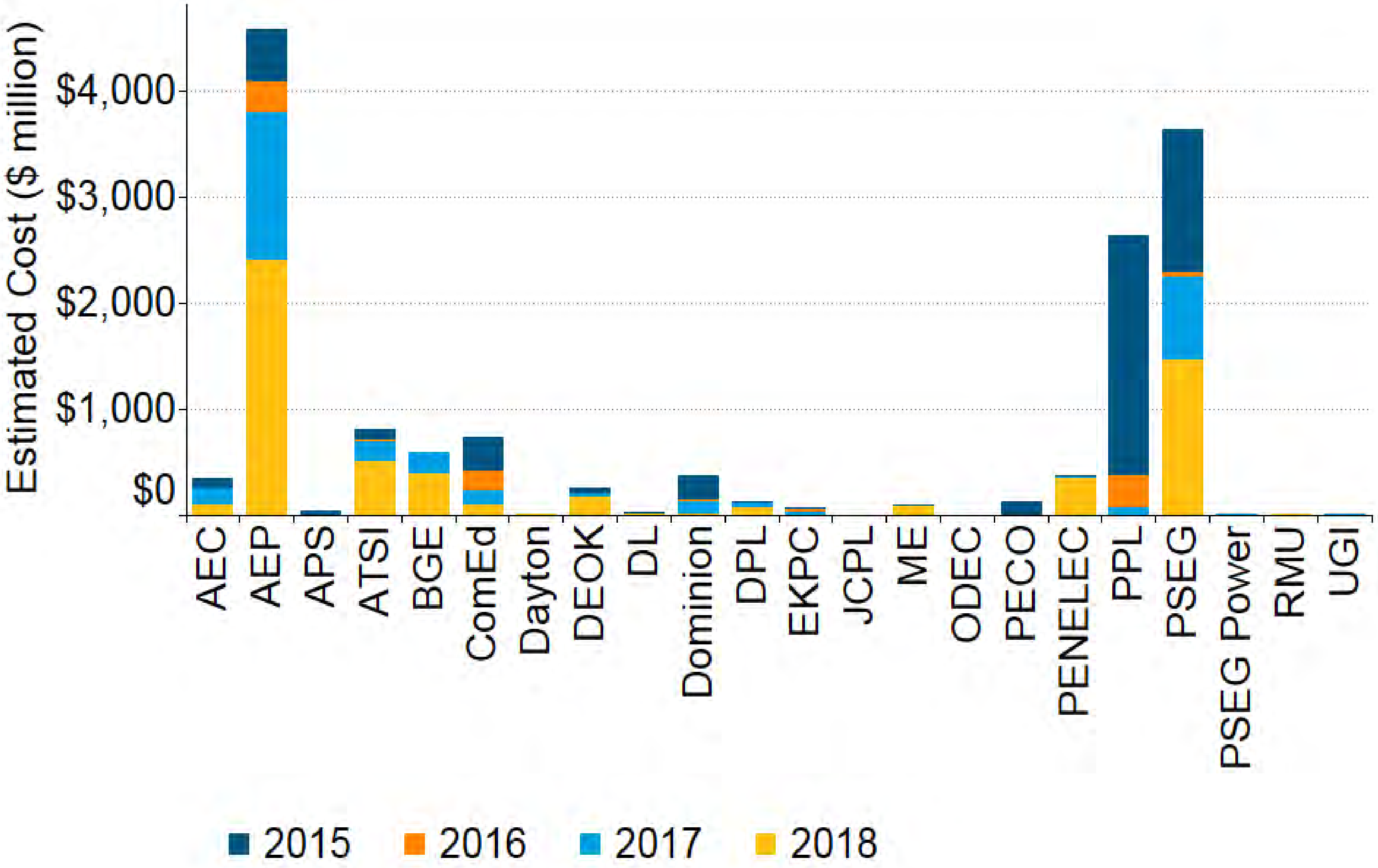
	NERC/PJM Criteria Violatio..	TO Criteria Violations
AEC	$39	
AEP	$428	$698
APS	$257	$1
ATSI	$115	
BGE	$99	
ComEd	$226	
Dayton	$1	
DEOK	$56	
DL	$51	
Dominion	$423	$1,800
DPL	$9	
EKPC	$5	$40
Exelon Genera..	$1	
JCPL	$3	$21
LS POWER	$146	
ME	$24	$6
MISO	$4	
NIPSCO	$16	
OVEC	$0	
PECO	$43	
PENELEC	$113	$9
PPL	$44	$79
PSEG	$534	$2,525
PSEG Nuclear	$0	
PSEG Power	$9	
RECO		$22
RMU	$4	
Transource	$197	$72
UGI	$0	

Baseline Projects by Designated Entity Approved by PJM Board 2015-2018



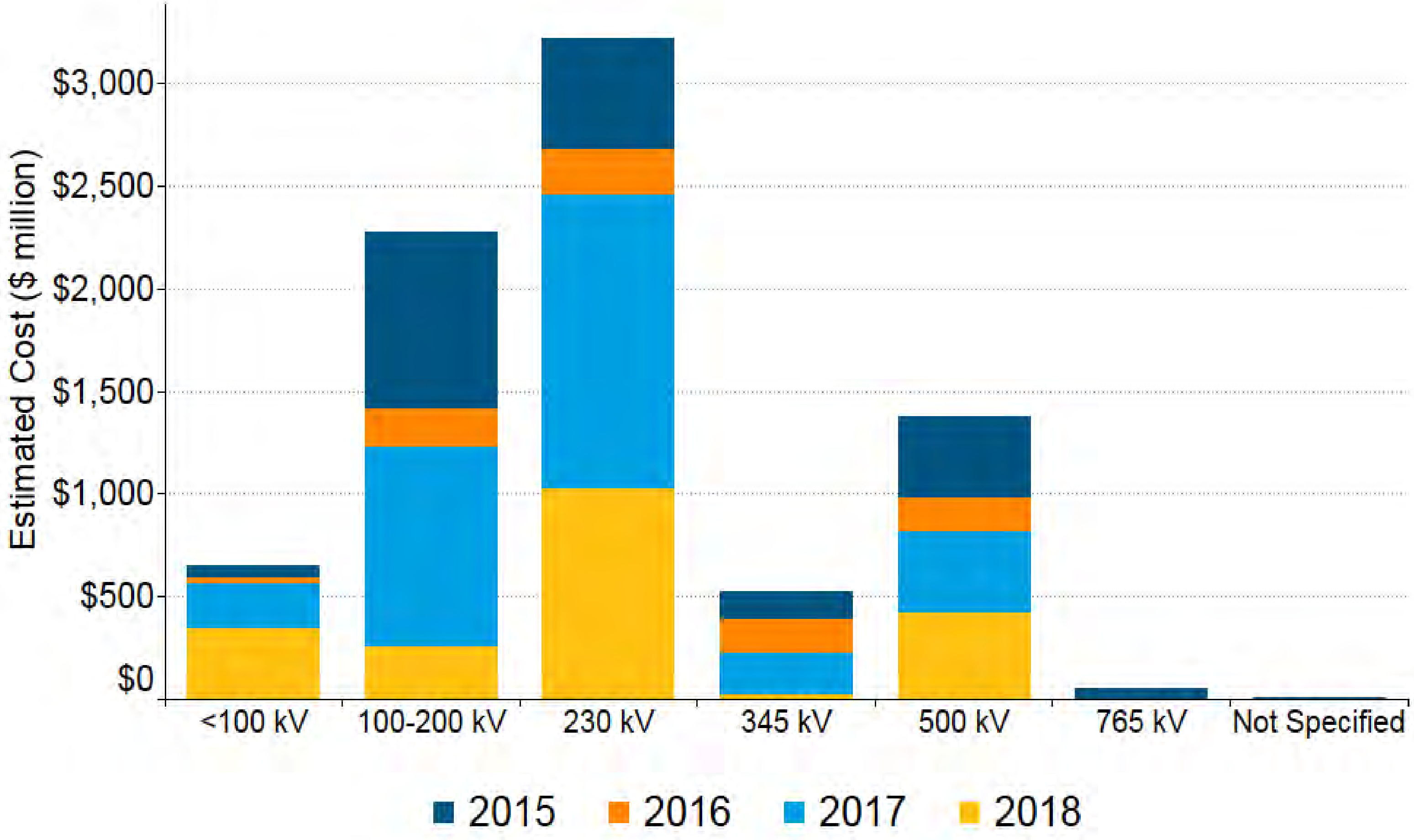
	Eligible for Competitive Window	Not Eligible for Competitive Window
AEC		$39
AEP	$402	$724
APS	$87	$171
ATSI	$33	$82
BGE	$93	$6
ComEd	$43	$183
Dayton		$1
DEOK	$40	$16
DL	$11	$40
Dominion	$203	$2,020
DPL	$4	$5
EKPC	$6	$39
Exelon Generation		$1
JCPL	$23	$1
LS POWER	$146	
ME	$15	$15
MISO		$4
NIPSCO		$16
OVEC		$0
PECO	$23	$20
PENELEC	$40	$81
PPL	$4	$119
PSEG	$132	$2,927
PSEG Nuclear	$0	
PSEG Power		$9
RECO		$22
RMU		$4
Transource	$269	
UGI		$0

Supplemental Projects by Transmission Owner Presented to the TEAC/Sub-regional TEAC Meetings in 2015-2018



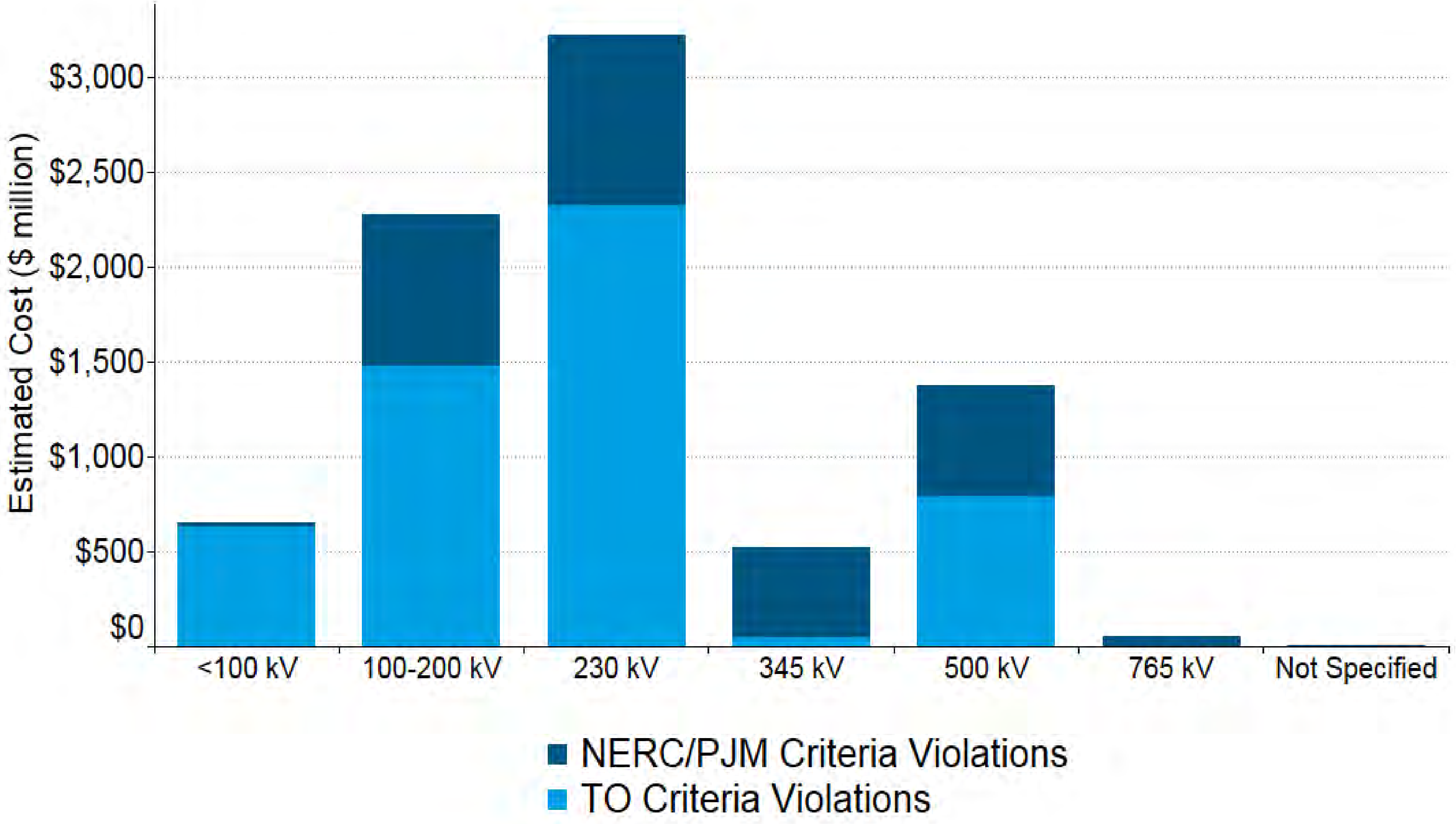
	2015	2016	2017	2018
AEC	$97		$157	$98
AEP	$493	$295	$1,386	$2,412
APS	$40	$1		$0
ATSI	$102	$3	$193	$511
BGE			$207	$394
ComEd	$317	$186	$137	$98
Dayton				$8
DEOK	$53		$33	$173
DL	$11		$4	$21
Dominion	$235	$6	$124	$17
DPL	$17		$46	$69
EKPC	$10	$33	$35	
JCPL	$0			
ME	$4			$95
ODEC	$1			
PECO	$135		$1	
PENELEC	$1	$0	$21	$355
PPL	$2,262	$306	$70	
PSEG	$1,340	$49	$788	$1,458
PSEG Power			$10	
RMU				$17
UGI			$0	$9

Baseline Projects by Voltage Approved by PJM Board 2015-2018



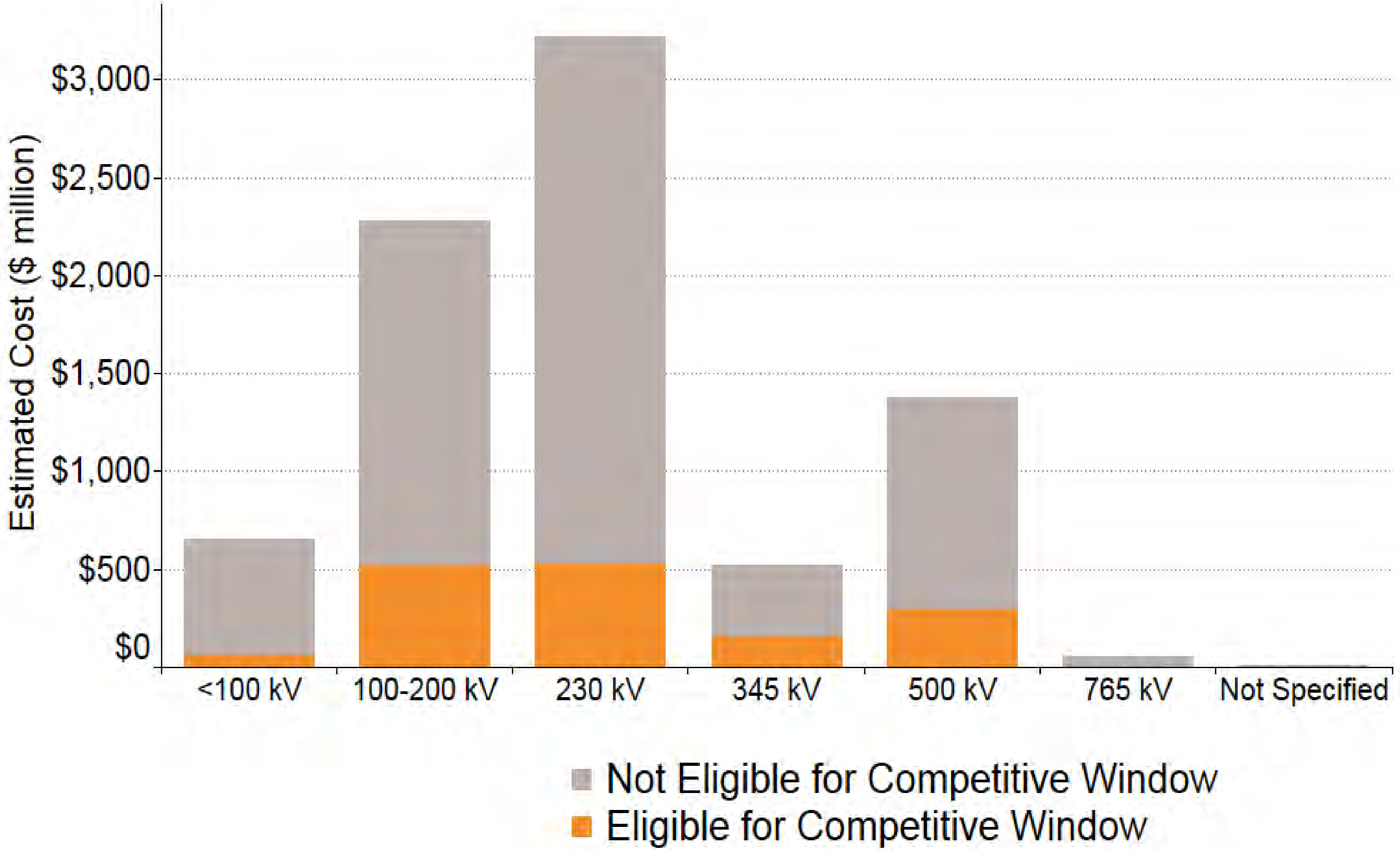
	2015	2016	2017	2018
<100 kV	$65	$25	$219	$345
100-200 kV	$860	$186	$979	$252
230 kV	$543	$223	$1,431	$1,026
345 kV	$135	$161	$208	$20
500 kV	$399	$165	$398	$418
765 kV	$52			
Not Specified	$0			$10

Baseline Projects by Voltage Approved by PJM Board 2015-2018



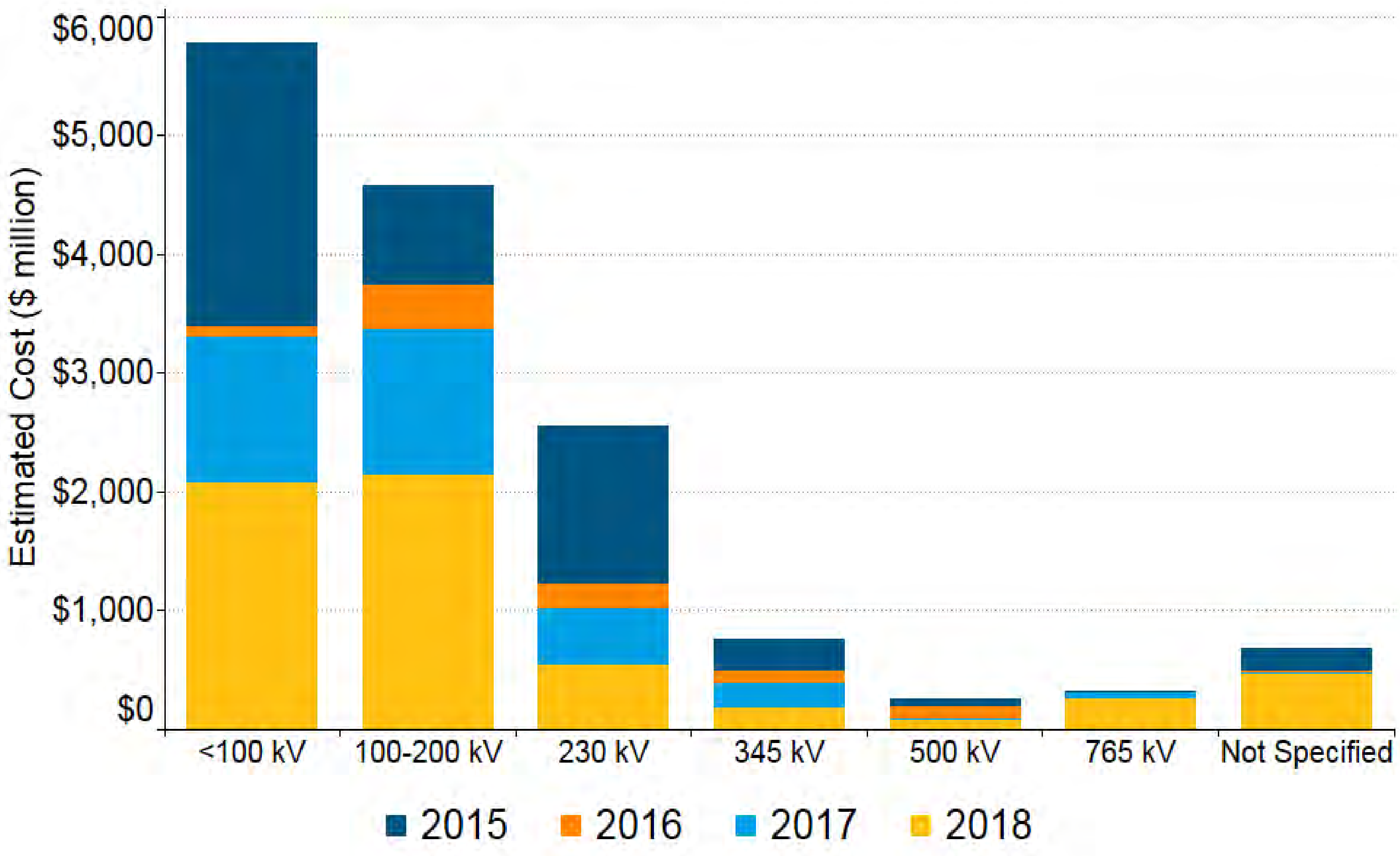
	NERC/ PJM Criteria Violations	TO Criteria Violations
<100 kV	$25	$630
100-200 kV	$799	$1,477
230 kV	$898	$2,325
345 kV	$481	$43
500 kV	$583	$796
765 kV	$52	
Not Specified	$9	$1

Baseline Projects by Voltage Approved by PJM Board 2015-2018



	Eligible for Competitive Window	Not Eligible for Competitive Window
<100 kV	$63	$591
100-200 kV	$518	$1,758
230 kV	$532	$2,690
345 kV	$155	$369
500 kV	$297	$1,082
765 kV	$1	$51
Not Specified	$9	$1

Supplemental Projects by Voltage Presented to the TEAC/Sub-regional TEAC Meetings in 2015-2018



	2015	2016	2017	2018
<100 kV	$2,386	$79	$1,232	$2,076
100-200 kV	$839	$379	$1,225	$2,139
230 kV	$1,331	$205	$485	$537
345 kV	$281	$97	$204	$183
500 kV	$68	$105	$3	$85
765 kV	$19		$50	$255
Not Specified	$193	$13	$13	$460

Revision History

V1 – 01/07/2019 – Original Slides Posted

ATTACHMENT M-3

ADDITIONAL PROCEDURES FOR PLANNING OF SUPPLEMENTAL PROJECTS

This document provides additional details of the process that PJM and the PJM Transmission Owners will follow in connection with planning Supplemental Projects, as defined in section 1.42A.02 of the Operating Agreement, in accordance with Schedule 6 of the Operating Agreement. This process will only apply to Transmission Owners that plan Supplemental Projects

1. **Review of Supplemental Projects.** As described in sections 1.3(c) and (d) of Schedule 6 of the Operating Agreement, the Subregional RTEP Committees shall be responsible for the review of Supplemental Projects. The Subregional RTEP Committees shall have a meaningful opportunity to participate and provide feedback, including written comments, throughout the transmission planning process for Supplemental Projects. Disputes shall be resolved in accordance with the procedures set forth at Schedule 5 of the Operating Agreement.

2. **Review of Assumptions and Methodology.** In accordance with sections 1.3(d), 1.5.4(a), and 1.5.6(b) and 1.5.6(c) of Schedule 6 of the Operating Agreement, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting to review the criteria, assumptions, and models Transmission Owners propose to use to plan and identify Supplemental Projects (Assumptions Meeting). Each Transmission Owner shall provide the criteria, assumptions, and models to PJM for posting at least 20 days in advance of the Assumptions Meeting to provide Subregional RTEP Committee Participants sufficient time to review this information. Stakeholders may provide comments on the criteria, assumptions, and models to the Transmission Owner for consideration either prior to or following the Assumptions Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Assumptions Meeting and may respond or provide feedback as appropriate.

3. **Review of System Needs.** No fewer than 25 days after the Assumptions Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review the identified criteria violations and resulting system needs, if any, that may drive the need for a Supplemental Project (Needs Meeting). Each Transmission Owner will review the identified system needs and the drivers of those needs, based on the application of its criteria, assumptions, and models that it uses to plan Supplemental Projects. The Transmission Owners shall share and post their identified criteria violations and drivers no fewer than 10 days in advance of the Needs Meeting. Stakeholders may provide comments on the criteria violations and drivers to the Transmission Owner for consideration prior to, at, or following the Needs Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the Needs Meeting and may respond or provide feedback as appropriate.

4. **Review of Potential Solutions.** No fewer than 25 days after the Needs Meeting, each Subregional RTEP Committee shall schedule and facilitate a minimum of one Subregional RTEP Committee meeting per planning cycle to review potential solutions for the identified criteria violations (Solutions Meeting). The Transmission Owners shall share and post their potential solutions, as well as any alternatives identified by the Transmission Owners or stakeholders, no fewer than 10 days in advance of the Solutions Meeting. Stakeholders may provide comments on the potential solutions to the Transmission Owner for consideration either prior to or following the Solutions Meeting. The Transmission Owner shall review and consider comments that are received within 10 days of the meeting and may respond or provide feedback as appropriate.

5. **Submission of Supplemental Projects.** Each Transmission Owner will finalize for submittal to the Transmission Provider Supplemental Projects for inclusion in the Local Plan in accordance with section 1.3 of Schedule 6 of the Operating Agreement and the schedule established by the Transmission Provider. Stakeholders may provide comments on the Supplemental Projects in accordance with section 1.3 of Schedule 6 of the PJM Operating Agreement before the Local Plan is integrated into the Regional Transmission Expansion Plan. Each Transmission Owner shall review and consider comments that are received at least 10 days before the Local Plan is submitted for integration into the Regional Transmission Expansion Plan.

6. **Information Relating to Supplemental Projects.** Information relating to each Transmission Owner's Supplemental Projects will be provided in accordance with, and subject to the limitations set forth in, section 1.5.4 of Schedule 6 of the Operating Agreement. Local Plan Information will be provided to and posted by the Office of Interconnection as set forth in section 1.5.4(e) of Schedule 6 of the Operating Agreement.

7. **No Limitation on Additional Meetings and Communications.** Nothing in this Attachment M-3 precludes any Transmission Owner from agreeing with stakeholders to additional meetings or other communications regarding Supplemental Projects, in addition to the Subregional RTEP Committee process.

Modifications. This Attachment M-3 may only be modified under Section 205 of the Federal Power Act if the proposed modification has been authorized by the PJM Transmission Owners Agreement-Administrative Committee in accordance with Section 8.5 of the Consolidated Transmission Owners Agreement.

Supplemental Projects Planning Process

Lessons Learned

Amber Thomas
Sr. Transmission Regulatory Specialist, PPL EU

April 12, 2019

Drivers of Supplemental Projects

- Supplemental Projects are transmission expansions or enhancements that are required to address:
  - Equipment Material Condition, Performance, and Risk
  - Operational Flexibility and Efficiency
  - Infrastructure Resilience
  - Customer Service
  - Other Drivers
- While Supplemental Projects have a range of drivers, they improve or preserve the PJM TOs' ability to provide reliable service to their customers consistent with their obligation to serve and are grounded in good utility practice

Drivers of Supplemental Projects

- **As listed in each of the PJM TOs' Assumptions presentations for the Subregional RTEP meetings, there are five major drivers of Supplemental Projects:**

1. Equipment Material Condition, Performance, and Risk: Degraded equipment performance, material condition, obsolescence, equipment failure, employee and public safety, and environmental impact.
   – These projects are investments needed to ensure the safe and reliable operation of the transmission system. The decision to pursue such projects can be based on equipment performance, obsolescence and expected service life concerns, condition of equipment, reliability impact, increased maintenance costs, and engineering recommendations.
2. Operational Flexibility and Efficiency: Optimizing system configuration, equipment duty cycles, and restoration capability; minimizing outages.
   – These projects can reduce the impact on and limit exposure to our customers for planned or forced events and can facilitate improved restoration times. They can also opportunistically bring the system up to current standards and design principles.

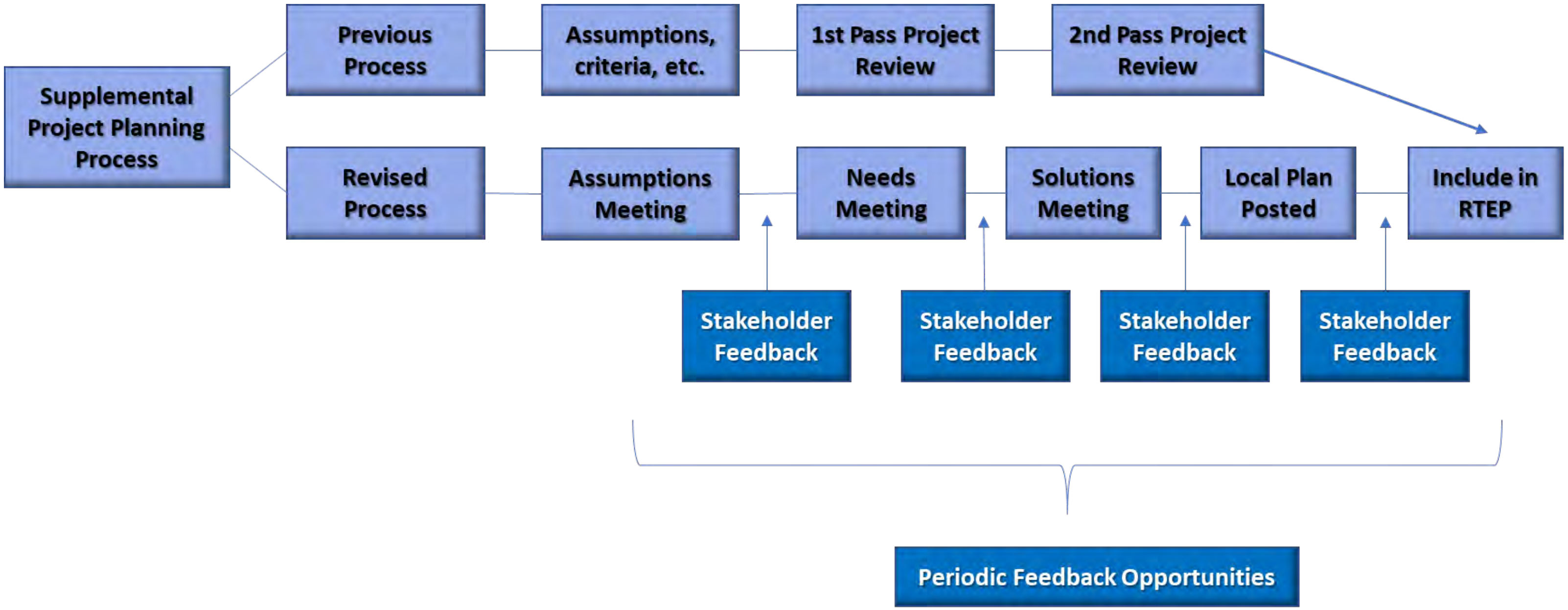
Drivers of Supplemental Projects

3. Infrastructure Resilience: Improve system ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event, including severe weather, geo-magnetic disturbances, physical and cyber security challenges, and critical infrastructure reduction.
   – These projects are designed to reduce the impact to our customers of disruptive natural or man made events. These projects can also improve the operability of the system and will reduce customer exposure.
4. Customer Service: Service to new and existing customers. Interconnect new customer load. Address distribution load growth, customer outage exposure, and equipment loading.
   – These projects accommodate new, increasing, or future load so that the system can reliably address customer needs. They also include improvements to facilities that serve our customers.
5. Other Drivers: Meet objectives not included in other definitions.
   – Project drivers can include: industry recommendations, potential generation retirements, technological pilot projects, and state policy objectives.

Supplemental Project Planning Process Attachment M-3

- FERC directed changes to the Attachment M-3 Supplemental Project planning process proposed by the PJM TOs in its February 15, 2018 Order (ER17-179).
  - Changes directed by FERC to ensure compliance with Order No. 890's transparency and coordination principles.
  - Stakeholders receive information about the assumptions, needs, solutions and Local Plans behind Supplemental Projects through stakeholder meetings, the PJM website, and discussions with the PJM TOs coordinated by PJM.
  - Per FERC's directives, Subregional RTEP and TEAC processes include (1) the criteria, models, and assumptions that they use in planning Supplemental Projects, (2) identified transmission needs, (3) proposed transmission solutions, and (4) Local Plan submittals through separate meetings and/or in separate postings, each preceded and followed by the opportunity for stakeholder feedback.

Supplemental Project Planning Process – Attachment M-3



- Revised process: Assumptions, Needs, and Solutions Meetings and Local Plan Submittal
  - The three meetings are separated by a minimum 25-day review period, allowing sufficient time for stakeholders to provide feedback before and after meetings and for the PJM TOs to consider that feedback
  - Prior to finalizing, PJM performs a "do no harm" analysis after the solutions meeting to ensure that the selected solution does not result in other reliability criteria violations
  - PJM also considers whether there is a Baseline Project that already meets the identified need
  - Timelines in Appendix

Significant Enhancement and Progress

Process Elements	2008 – 2016	M-3 Process – 2019
Materials Posted In Advance	Yes	Yes
Opportunity for Stakeholder Feedback Before and After Meetings	Yes	Yes
Unique Slide Identifiers	No	Yes
Process Stage Identifiers	No	Yes
Assumption References	No	Yes
Bubble Diagrams	Infrequently	Yes
Separate Discussions of Needs and Solutions	No	Yes
Guidance to Stakeholders on Comment & Process Status	No	Yes
Standardization of TO Presentations	No	Yes (work continues)
Regularly Scheduled Meetings	As Needed	Yes
Project Drivers	Sometimes	Yes
Problem Statements	Sometimes (less detail)	Yes
Alternatives	Sometimes (less detail)	Yes
Maps	Sometimes (less detail)	Yes

Continuing Process Improvements

- The PJM TOs are fully complying with the requirements of the Show Cause Order.
- In implementing the Attachment M-3 process, the PJM TOs have enhanced transparency.
  - CONSISTENCY: With PJM, the PJM TOs worked to ensure consistency in the types of information that the PJM TOs present at the Subregional RTEP and TEAC meetings and throughout the Supplemental Project planning process
  - RESPONSIVENESS: In the six months since the Attachment M-3 process has been implemented, the PJM TOs have been responsive to stakeholder requests for information
  - COLLABORATION: PJM and the PJM TOs have committed to stakeholders to schedule periodic “lessons learned sessions” to gather stakeholder feedback on the Attachment M-3 process
- The PJM TOs remain committed to working with PJM and Stakeholders on further improvements to Attachment M-3 Process

APPENDICES

APPENDIX 1

Supplemental Project Planning Process – Assumptions Meeting

	Activity	Timing	Day	Who	How
1	Posting of Annual Assumptions Meeting date (others may occur throughout the year as needed)	Annually	-45 (approx.)	PJM	Web posting on Sub-regional RTEP pages
2	Submittal of materials for Annual Assumptions Meeting	5 days before posting date 25 days before Assumptions meeting	-25	TO	Email to PJM
3	Posting of TO Assumptions meeting information	20 days before Assumptions Meeting	-20	PJM	Web posting of meeting materials
4	Assumptions Meeting		0	All	
5	Stakeholder Comments	10 days after Assumptions Meeting	+10	Stakeholders	Email to PJM, PJM posts comments
6	TOs review and consider stakeholder comments	10 days after comments received	> +10	TOs	Based upon comments, TO may add information in revised slides sent to PJM and PJM re-posts

Supplemental Project Planning Process – Needs Meeting

	Activity	Timing	Day	Who	How
1	Send Needs Meeting slides to PJM	15 days prior to Needs Meeting	-15	TO and Stakeholders	Email to PJM
2	Finalize Needs Meeting slides (i.e., add maps)	Upon receipt of slides, prior to posting date	> -10	PJM	Revises supplied slides
3	Posts Needs Meeting slides	10 days before Needs Meeting	-10	PJM	Web posting of meeting materials
4	Needs Meeting		0	All	
5	Stakeholder Comments	10 days after Needs Meeting	+10	Stakeholders	Email to PJM, PJM posts comments
6	TOs review and consider stakeholder comments	10 days after comments received	> +10	TOs	Based upon comments, TO may add information in revised slides sent to PJM and PJM re-posts

Supplemental Project Planning Process – Solutions Meeting

	Activity	Timing	Day	Who	How
1	Send Solutions Meeting slides, and for proposed solution modeling information (contingency files, IDEV, etc.) to PJM	15 days prior to Solutions Meeting	-15	TOs and Stakeholders	Email to PJM
2	Finalize Solutions Meeting slides (i.e., add single-line diagrams)	Upon receipt of slides, prior to posting date	> -10	PJM	Revises supplied slides
3	Posts Solutions Meeting slides	10 days before Solutions Meeting	-10	PJM	Web posting of meeting materials
4	Solutions Meeting		0	All	
5	Stakeholder Comments	10 days after Solutions Meeting	+10	Stakeholders	Email to PJM, PJM posts comments
6	TOs review and consider stakeholder comments	10 days after comments received	> +10	TOs	Based upon comments, TO may add information in revised slides sent to PJM and PJM re-posts
7	No Harm analysis performed for proposed solution	After comments for Solution Meeting	> +10	PJM	Web posting indicating status on Solutions Meeting slide

Supplemental Project Planning Process – Local Plan Submittal

	Activity	Timing	Day	Who	How
1	Send Local Plan slides (including Comment Deadline) with selected solutions and updated modeling information (if necessary) to PJM	TO discretion		TOs	Email to PJM
2	Finalize Local Plan slides if necessary (i.e., updated maps, etc.)	Upon receipt of slides, prior to posting date		PJM	
3	Local Plan posted (including comment deadline)	5 days after receipt of slides		PJM	Web posting (PJM to determine appropriate location)
4	Stakeholder comment deadline	At least 10 days after Local Plan posting	> -10	Stakeholders	Email to PJM, PJM posts comments
5	Review and consider Stakeholder Comments	Until Local Plan submittal	> -10	TOs	Based upon comments, TO may add information in revised slides sent to PJM and PJM re-posts
6	Local Plan submitted for integration into RTEP	At least 10 days after comment deadline	0	TOs	Email final Local Plan slides to PJM
7	Post final Local Plan slides	5 days after receipt of slides	+5	PJM	Web posting (PJM to determine appropriate location)

APPENDIX 2

Supplemental Project Planning Process – Needs Template

<TO> Transmission Zone M-3 Process
<locale>

Need Number: <need ID>

Process Stage: Need Meeting <date>

Supplemental Project Driver:
<driver>

Specific Assumption References:
<assumption>

Problem Statement:
<description>

Geographic Map:
Include all facilities mentioned on slide, small locator map and a legend.

Supplemental Project Planning Process – Solutions Template

<TO> Transmission Zone M-3 Process
<project name>

Need Number: <need ID>

Process Stage: Solutions Meeting <date>

Previously Presented:
<stage> <date>

Supplemental Project Driver:
<driver>

Specific Assumption References:
<reference>

Problem Statement:
<description>

Geographic Map:
Include all facilities mentioned on slide, small locator map and a legend.

Supplemental Project Planning Process – Solutions Template

<TO> Transmission Zone M-3 Process

<project name>

Need Number: <need ID>

Process Stage: Solutions Meeting <date>

Proposed Solution:

<description> <cost>

Alternatives Considered:

1. <description> <cost>
2. <description> <cost>

Projected In-Service: <IS-Date>

Bubble Diagram

Supplemental Project Planning Process – Inclusion in Local Plan Template

<TO> Transmission Zone M-3 Process
<project name>

Need Number: <need ID>

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan <date>

Previously Presented:

<stage> <date>

<stage> <date>

Supplemental Project Driver:

<driver>

Specific Assumption References:

<reference>

Problem Statement:

<description>

Geographic Map:
Include all facilities mentioned on slide, small locator map and a legend.

Supplemental Project Planning Process – Inclusion in Local Plan Template

<TO> Transmission Zone M-3 Process
<project name>

Need Number: <need ID>

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan <date>

Selected Solution:

<description>

Estimated Cost: <cost>

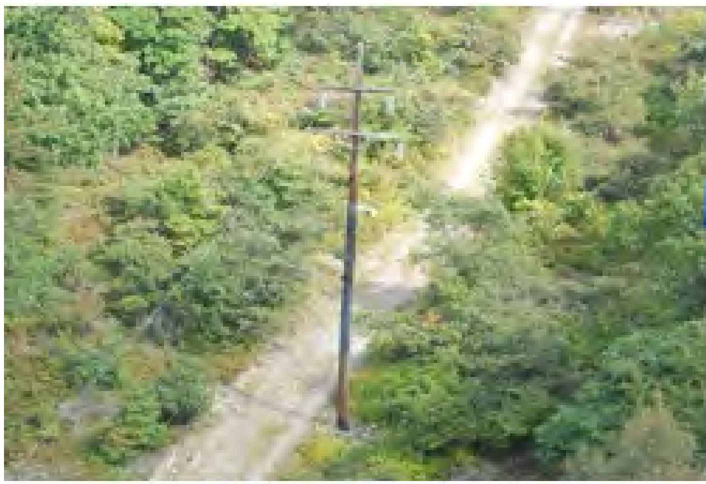
Projected In-Service: <IS-Date>

Supplemental Project ID: <sxxxx>

Bubble Diagram

APPENDIX 3

Example: Equipment Material Condition, Performance and Risk



Typical Aging Infrastructure

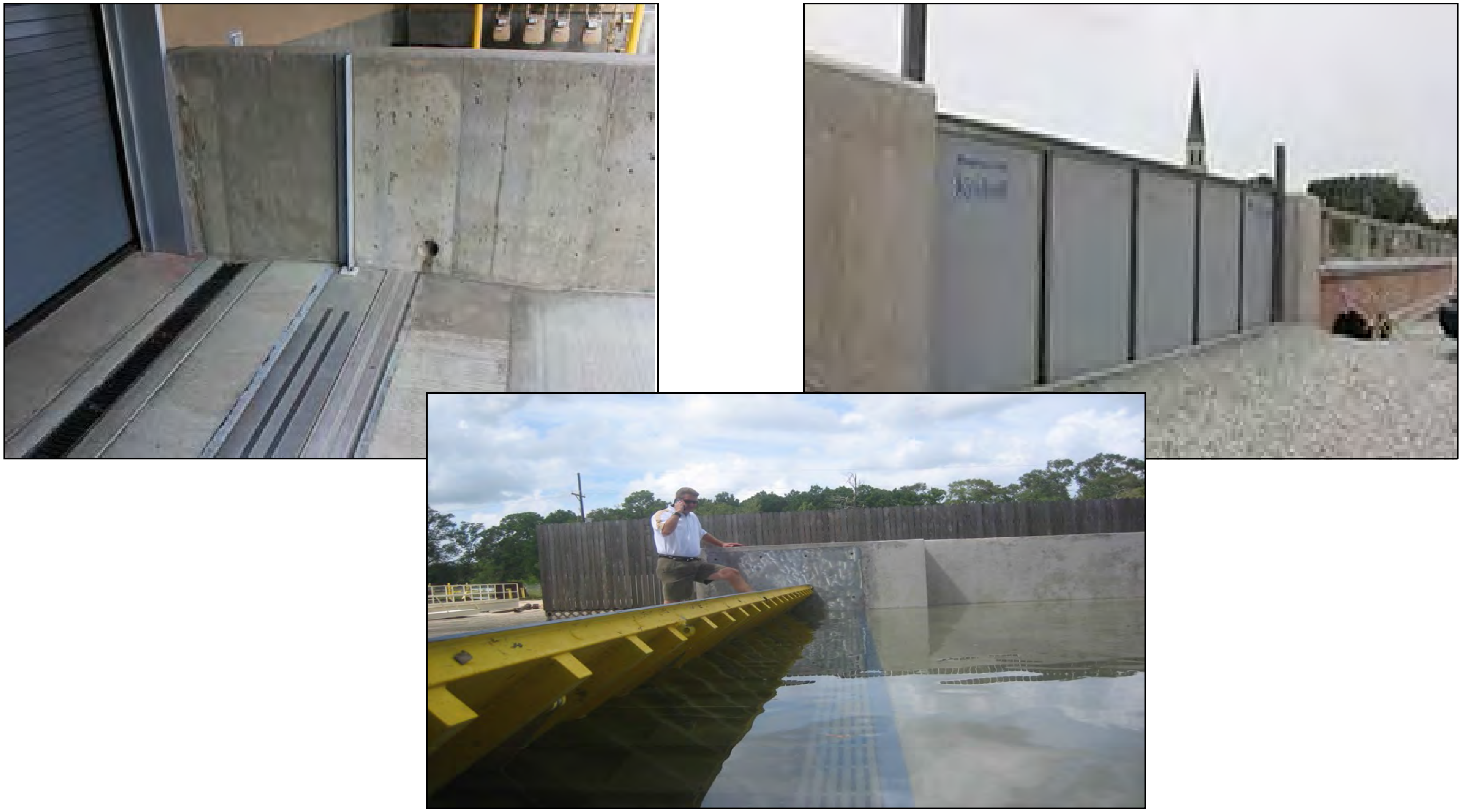
Typical New Construction

Example: Infrastructure Resilience

PSE&G Ewing Substation Storm Hardening

Example: Infrastructure Resilience

BGE Concord Street Substation



Example: Equipment Material Condition, Performance and Risk

Poston-Harrison 138 kV Line

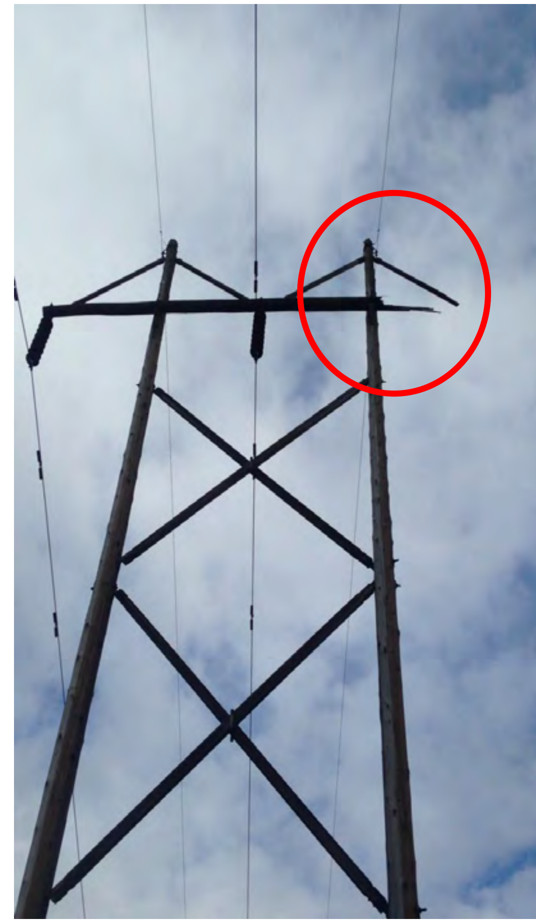
Retire and rebuild approximately 55 miles of 1954 vintage 138 kV system in Athens and Hocking County, Ohio.

Cost: $62 million	In-service Date: June 2019

Example: Equipment Material Condition, Performance and Risk

Burnt hole in pole

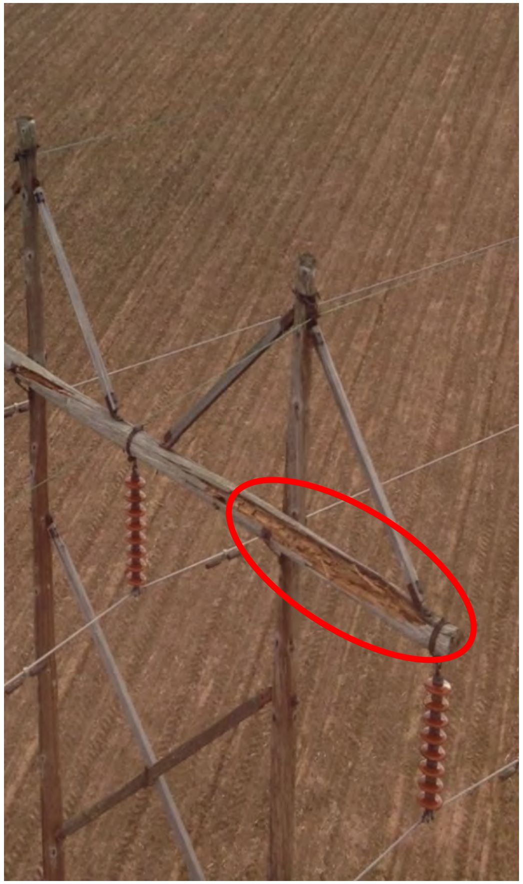
Split pole with rot heart



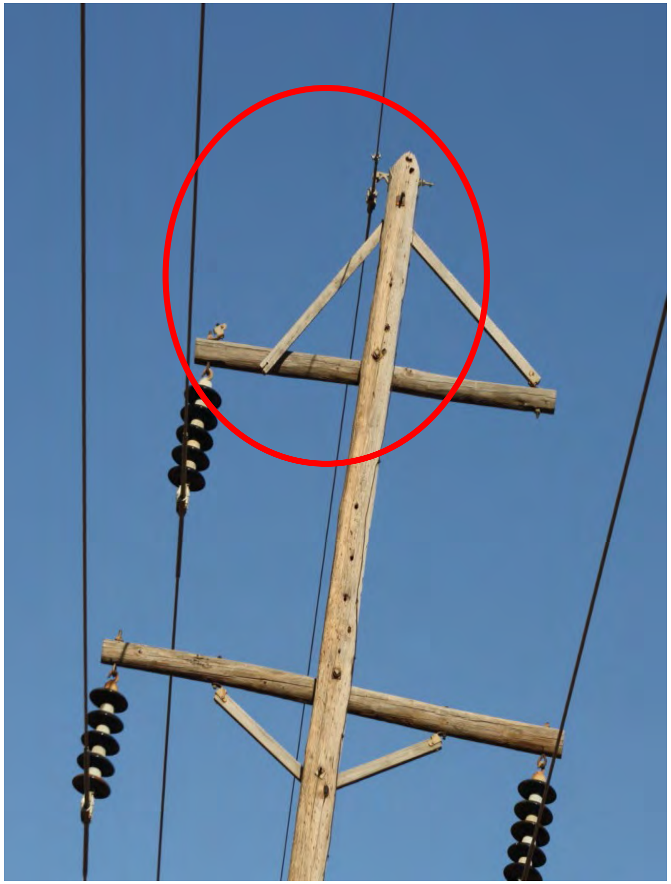
Rotten crossarm

Example: Equipment Material Condition, Performance and Risk

Ground line rot with potential to affect shell



Rotten crossarm



Disconnected top brace

Questions?

Twin Branch / Edison Area Load Shed Event
May 29, 2018

July 5th SOS

Agenda

- Area overview
- System conditions prior to the event
- Sequence of Events
- PAI Analysis
- Recommendations

Area overview

System conditions prior to the event

- Hot Weather Alert issued for the RTO

- Jackson Rd – Ireland Rd 138kV line out of service
  - Supplemental project s1582
  - Outage began on 4/18

- Darden Rd – South Bend 138kV line AND Notre Dame – South Bend 138kV line out of service
  - Supplemental projects s1611.2-.8
    - Pouring new foundations
  - Both outages began on 5/29
  - Hot Weather Alerts request Transmission and Generation owners to defer maintenance, but do not prohibit new outages from starting. Outages are cancelled by PJM if there are any reliability concerns identified in real time (RT) or day ahead (DA) studies:
    - RT and DA N-1 analyses by both PJM and AEP indicated no issues. Outages were both recallable.

Sequence of Events

- 12:36 - Twin Branch - Jackson Rd 138 kV line AND the Jackson Rd 345/138 kV transformer 3 tripped
  - The Twin Branch-Jackson Rd trip was a result of contact with a tree
  - The Jackson Rd 'J1' CB relayed out due to a momentary reverse fault being detected that subsequently opened the low side of the Jackson Rd 345/138kV transformer.

- 12:48 – Contingency overloads confirmed:
  - Edison-Kankakee 138kV line for loss of Twin Branch #6 & #7 345/138kV transformers at 140% of LTE
    - Due to the breaker configuration, loss of the Twin Branch #6 and #7 transformers concurrently is a single contingency
  - Edison-Kankakee 138kV line for loss of Twin Branch – South Bend 138kV line at 132% of LTE
    - PJM operators begin coordination with AEP operators to review generation and switching options
    - No controlling actions were available, M-13 Section 5.4.1 Cascade Analysis begins

- 12:59 – PJM completes the cascade analysis for loss of the Edison-Kankakee and the Twin Branch #6 & #7 transformers. The analysis indicates this scenario does NOT result in a potential cascade.

Sequence of Events

- 13:00 – PJM begins second cascade analysis, taking out the Edison-Kankakee 138kV line and the Twin Branch – South Bend 138kV line

- 13:05 – PJM issues a PCLLRW on the Edison-Kankakee 138kV line for loss of Twin Branch #6 & #7 345/138kV transformers

- 13:12 – PJM completes the cascade analysis for loss of the Twin Branch – South Bend 138kV line.
  - The analysis indicated this contingency scenario "did not solve" and <u>may be a cascade condition</u>.

- 13:15 – PJM recalls the Darden Rd - South Bend and Notre Dame – South Bend 138kV lines

Sequence of Events

- 13:22 – After reviewing the cascade analysis results with AEP, PJM directed AEP to shed load in the impacted area to reduce the contingency flow on the Edison-Kankakee line
    - **PAI trigger**

- 13:37 - The Jackson Rd 345/138 kV transformer 3 was restored

- 13:46 - PJM analysis confirms the cascade condition has been mitigated by the return of the transformer and cancels the load shed

- 13:55 - AEP completes restoration of load that had been shed (approx. 21 MWs)

Sequence of Events

- 15:27 – Notre Dame – South Bend restored
- 16:20 – Darden Rd – South Bend restored
- 23:57 - The Twin Branch - Jackson Rd 138 kV line was restored

PAI Analysis

- PAI Analysis:
  - There are no Non-Performance Charges or Bonus Credits resulting from the event
  - Data confidentiality rules prevent the disclosure of more detailed data to members.

NOTE: There was no possible generation dispatch (online or offline units) that would have mitigated overloads. The overloads were a result of a localized load pocket caused by the transmission outages.

Recommendations

- Recommendations:
  - Relay Settings:
    - AEP reviewed and updated the relay settings associated with the Jackson Rd J1 breaker.
  - Outage Approvals:
    - PJM will review the outage approval process during emergency procedures, including possible N-1-1 analysis.
  - Technology
    - PJM will review tools and technology to develop alternative methods to provide a solution when a contingency ‘doesn’t solve’.
  - Manual language
    - Reviewing M-3 and M-13 language for improvements and clarity based on operator feedback

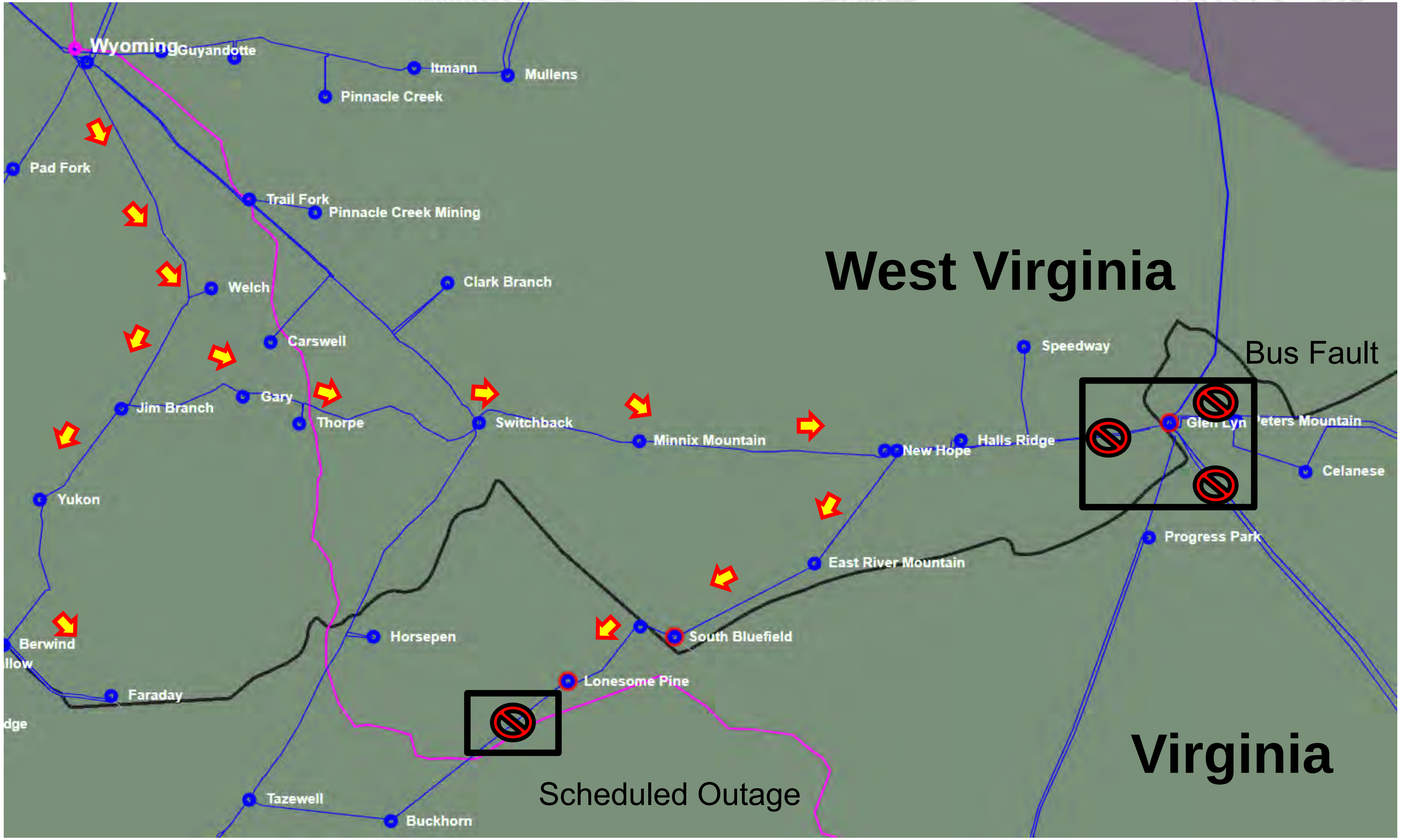
Lonesome Pine Load Shed Event
July 18, 2018

Donnie Bielak
Manager, Reliability Engineering

Agenda

- Overview
- Sequence of Events
- PAI Analysis

Overview


Wyoming
Guyandotte
Itmann
Mullens
Pinnacle Creek
Pad Fork
Trail Fork
Pinnacle Creek Mining
Welch
Clark Branch
Carswell
West Virginia
Speedway
Bus Fault
Gary
Jim Branch
Thorpe
Switchback
Minnix Mountain
New Hope
Halls Ridge
Glen Lyn
Peters Mountain
Celanese
Yukon
Progress Park
East River Mountain
Horsepen
South Bluefield
Berwind
Lonesome Pine
Faraday
Scheduled Outage
Virginia
Tazewell
Buckhorn

Sequence of Events

- **Monday 7/16/18**
  - **06:35**: Buckhorn – Lonesome Pine 138 kV line removed from service to perform scheduled maintenance
- **Wednesday 7/18/18**
  - **09:37**: Glen Lyn 138 kV bus tripped creating load pocket
    - Load pocket fed radially from Wyoming (no violations)
  - **10:52**: South Bluefield 138 kV capacitor switches in service automatically and trips/locks with South Princeton 138 kV capacitor
    - Results in severe low voltages in the area 5 kV below load dump
    - PJM directs AEP to shed load to return voltages to acceptable levels

Sequence of Events

- **Wednesday 7/18/18**
  - **11:14**: AEP sheds approximately 32 MW of load
    - Approximately 11,860 customers in West Virginia and Virginia
  - **12:37**: South Princeton capacitor restored
  - **12:37**: All 32 MW of load restored
  - **12:54**: Glen Lyn 138 kV bus returned to service
  - **14:23**: Buckhorn – Lonesome Pine 138 kV line returned to service

PAI Analysis

- PAI Analysis
  - There are no Non-Performance Charges or Bonus Credits resulting from the event
  - There was no possible generation dispatch (online or offline units) that would have mitigated the voltage violations
  - The voltage violations were in a localized load pocket caused by the transmission outages

CERTIFICATE OF SERVICE

Indiana Office of Utility Consumer Counselor Public's Exhibit No. 7 Testimony of OUCC Witness Michael Gahimer has been served upon the following parties of record in the captioned proceeding by electronic service on August 20, 2019.

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