Accelerating the Integration of New Co-located Generation and Loads

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Executive Summary

Faster connection of large loads for artificial intelligence has been identified as a federal priority. Many new large loads such as data centers are applying to connect to the grid in PJM and elsewhere, creating opportunities for economic growth and higher utilization of electrical infrastructure.

This load growth is challenging both transmission and resource adequacy. In some cases, new large loads exceed existing transmission capacity, and new customers must wait while (potentially costly) transmission upgrades are made. In other cases, load growth exceeds projected additions of generating capacity. In many areas, concerns have been raised regarding the affordability implications for consumers of these transmission and capacity impacts from growth in large loads. The co-location of such loads with generation has emerged as one solution to address these transmission and resource adequacy challenges.[1] PJM Interconnection L.L.C. (PJM) recently validated co-location as a possible solution in its Answer to the Federal Energy Regulatory Commission (FERC) in Docket No. EL25-49-000.[2]

In this report we assess the concept of connecting new generation and co-located load as a composite facility called an "Energy Park." This approach can significantly reduce the need for new transmission while accelerating integration of new loads together with new generation resources that can ease resource adequacy concerns, reducing costly resource and grid investments and mitigating bill impacts for consumers. We assess current processes in PJM and identify possible reforms necessary to facilitate the interconnection of such Energy Parks.

The key findings in our study are as follows:

1. **Integrated Energy Park interconnection is a practical way to quickly connect large loads with fewer transmission upgrades**

[1] See for e.g., Large Loads Co-Located at Generating Facilities, Docket No. AD24-11-000 (technical conference held on November 1, 2024); Office of Policy, Department of Energy, Request for Information on Artificial Intelligence on DOE Lands (issued April 3, 2025).

[2] PJM, Answer of PJM Interconnection L.L.C, FERC Docket No. EL25-49-000, March 24, 2025, hereafter "PJM Answer."

Energy Parks connected to the transmission system consist of three components: generation, co-located load, and a mechanism to control flows into or out of the Energy Park at the point of interconnection (POI) with the transmission grid. Following the interconnection approach for Private Use Networks (PUNs) used in the Electric Reliability Council of Texas (ERCOT), we describe an Energy Park Integration (EPI) process that would study the Energy Park as a composite load and generation facility (at smaller scale referred to as a "micro grid"), instead of separately studying the load in one process and the generator in another.[3]

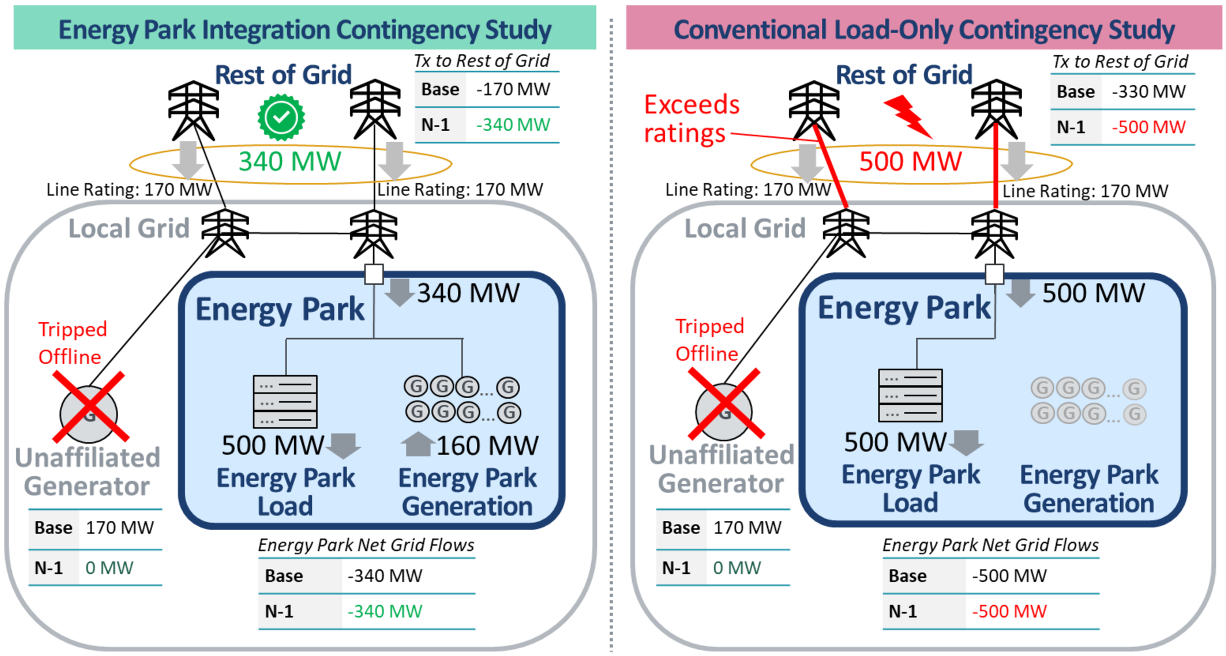
We illustrate stylized contingency cases (such as shown in Figure ES-1 below) that are used in reliability studies to show how an Energy Park studied as a composite facility can be connected to the grid more quickly and less expensively due to lower transmission upgrades relative to a conventional study approach. This is because, in the conventional approach, PJM and the transmission owner separately evaluate generation and load components respectively without consideration of the self-balancing effect of co-located generation on co-located load, and potentially ignore the action of a control system (and system protection mechanism) that limits Energy Park power flows to and from the grid to specified levels.

In all cases where the grid connection of the Energy Park itself is smaller than the Energy Park's load and generation, the park's embedded generation—such as a combination of fuel cells, natural gas resources, battery storage, and variable resources—would serve as the primary generation source supplying the relevant portion of the Energy Park's load. For the portion of Energy Park load that can be served from the grid, the embedded generation would both be dispatchable into the regional market and serve as backup generation for the Energy Park load.[4]

[3] *See* ERCOT Update to Texas House of Representatives Committee on State Affairs, March 5, 2025, at p. 6

[4] We understand from Energy Park developers that installed (backup or primary) generating capacity typically consists of numerous individual generators with surplus total capacity such that the planned or forced outage of individual Energy Park generators would not affect the Energy Park's ability to serve its load even if the grid connection is unavailable.

FIGURE ES-1: CONTINGENCY CASE FOR THE PROPOSED ENERGY PARK INTEGRATION APPROACH (LEFT) VS. CONVENTIONAL LOAD-ONLY APPROACH (RIGHT), SHOWING OVERLOADS AND UNNECESSARY UPGRADES IN THE LATTER



Notes: The local grid contains the Energy Park with 500 MW of co-located load and an array of co-located generators, as well as an unaffiliated generator nearby, all of which are connected to the rest of the grid by a pair of transmission lines that together can transfer 340 MW. While the local grid can host the 500 MW load of the data center in a base case by relying on grid imports that include the unaffiliated generator, such a base case would not be deemed secure to the contingency (the outage of the nearby unaffiliated generator) under conventional load-only study criteria as shown on the right, and would therefore require significant transmission upgrades. As shown on the left, these upgrades can be avoided when considering that the Energy Park's controls of load and generation will be able to limit grid imports to 340 MW (by dispatching at least 160 MW of self-generation within the Energy Park).

2. Accelerated interconnection of Energy Parks with co-located data center loads and new generation is in the interest of many stakeholders

PJM in its response to FERC stated there is nearly 8.5 GW of proposed large loads waiting to be connected to the transmission system and co-located with existing generation, and highlighted a faster interconnection option for new loads that are co-located with new generation (i.e., Energy Parks).[5]

Meanwhile, there are many more large new loads planned that will not be co-located with existing generation, representing much of the rapid increase in PJM load forecasts—which, in

[5] PJM Answer, Exhibit B, and New Option 6, at page 16

turn, is driving costly transmission upgrades and accelerating resource adequacy concerns. Most of these large consumers, while apparently standalone load, are in fact planning to install co-located backup generation. Because this backup generation typically consists of diesel generators that are only permitted to run for a limited number of hours per year, and are configured to run only while disconnected from the grid, most large load customers have not designed their backup generation to support system-wide transmission and resource adequacy needs (not even as self-supply capacity that seldom runs). However, by planning to co-locate new primary generation that can run at any time (as well as potentially providing backup power if needed), the new customer can supply all or part of its energy and resource adequacy on-site, minimizing the impact on markets and transmission and supporting the interconnected grid.[6]

Because an integrated EPI process as described in this report offers substantial benefits for developers to more quickly connect new loads in an Energy Park configuration, nearly all new large load customers would be incentivized to design their on-site generation plans such that, in addition to meeting backup power needs, it can also serve as primary generation to self-supply energy and resource adequacy and provide valuable grid support (as necessary). By incentivizing new large load customers to bring their own new generation, the proposed integrated Energy Park interconnection process offers a solution that can more quickly integrate large new loads (consistent with federal priorities) while addressing the resource adequacy and transmission challenges and lowering cost impacts on consumers.

3. **The benefits of an EPI approach are highest when Energy Parks are dispatchable by the transmission operator or regional market to dependably transact with the grid on an "as-needed" basis**

With dispatchable onsite generation such as fuel cells, gas turbines, or battery storage, an Energy Park can self-supply in full or in part (depending on configuration) its own load when (i) the grid is not available, (ii) purchases from the grid are not advantageous, or (iii) based on bilateral contractual terms (i.e., if during off-peak hours that the co-located generation is more than sufficient to meet the lower power needed by load).

At times, an Energy Park would not only be able to self provide the resource adequacy needs of its load, it would also be able to export power to the grid when grid capacity is available and surplus generation exists and is cost effective. This capability of the Energy Park can provide a

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[6] The on-site provision of energy and resource adequacy to the load could be through self-supply, through an arrangement with an independent generation owner, or with the local utility, depending on state law. Generation ownership is not determinative in applying the integrated EPI arrangement proposed here.

valuable reliability contribution to the grid to the extent such net injections are possible during times of scarcity or local emergencies.

By reflecting the controllable nature of Energy Park withdrawals and injections to the grid, EPI studies are less likely to conclude that expensive and time-consuming transmission upgrades are necessary, and therefore can facilitate the more timely interconnection of new loads. This outcome is premised on the grid operator's ability to rely on the Energy Park to control net injections or withdrawals depending on what the grid is able to accommodate in real-time operations. The energy market offer, clearing, and dispatch systems already used for other grid-connected generators, storage, and demand-response resources can be utilized for Energy Parks, provided that Energy Park operators follow the grid operators dispatch instructions for contingency response and market interactions.[7] Transmission planning benefits are maximized when an Energy Park is able to respond automatically to grid contingencies (transmission outages and generator outages) in coordination with PJM and transmission owner operations.

* * *

In summary, EPI is practical, addresses resource adequacy and grid challenges, and offers significant benefits if the Energy Park resources are dispatchable on as-needed basis. The adoption of an EPI process would greatly accelerate the interconnection of large new loads by replacing or supplementing backup-only generation with primary generation resources that can self-supply all or a portion of Energy Park loads, thereby mitigating the resource adequacy and transmission challenges and consumer cost impacts of rapid load growth.

As detailed in Section III below, we find that current practice in PJM would need to be enhanced via the following enabling reforms in order to obtain the benefits of the EPI study process:

- **PJM and transmission owner**: develop and document EPI protocols, applicable for Energy Parks, as an alternative to the currently applicable separate study processes, including the PJM generator interconnection study process, the PJM 'Do No Harm' study, transmission owner load integration study, and (in limited cases) the PJM regional transmission expansion process (RTEP). The EPI protocols would need to include provisions for

[7] While the main focus of this report is on Energy Parks with the ability to export to the grid, non-exporting Energy Parks could be similarly dispatched by PJM and transmission owners in real time operations (e.g., through modified demand response frameworks that are incorporated into security constrained economic dispatch).

coordination between separate study processes (unless the relevant parties integrate them into a single process).

- **PJM and/or transmission owner**: Document technical standards for the Energy Park controls and protection mechanisms used to limit physical withdrawals and injections between the Energy Park and the grid to the pre-specified amounts. Develop provisions to ensure that PJM and transmission operators can rely on the Energy Park to control net injections or withdrawals when grid capacity is limited (during contingencies) in real time operations.
- **PJM**: allow for and study non-firm grid injection requests based on "as available" grid capacity (i.e., less firm than current Energy-only interconnections). Study these non-firm Energy Park injections through an expedited screening process similar to that of PJM's new Surplus Interconnection Service (SIS) or Capacity Interconnection Rights (CIR) replacement processes, given that non-firm net injections by the Energy Park can be controlled automatically so they will not cause transmission impacts beyond the designated levels.[8]

[8] The SIS process is an accelerated path through the generation interconnection queue process that assesses the addition of new supply technologies to existing generators (e.g., adding solar to an existing combustion turbine interconnection point) as long as total injections can be controlled to stay within the limits of the existing interconnection service agreement. This allows for an expedited study process to confirm that the new configuration does not materially impact grid reliability. CIR replacement takes a similar approach to confirm absence of impact when a retiring generator is replaced with a different generation technology type at substantially the same interconnection point.

I. Introduction

PJM, the Regional Transmission Organization (RTO) serving 13 states and the District of Columbia, forecasts rapid growth in electricity demand, driven in large part by expansion of planned data centers and other large loads.[9] Transmission infrastructure and resource adequacy are being strained to integrate the new loads. In some cases, new large loads must wait years while time-consuming and costly transmission upgrades are made.[10] Importantly, PJM has expressed significant concerns over resource adequacy challenges.[11]

Speed to market is a critical motivation for many new large data center customers, as the ability to launch new services and scale operations is critical to competitiveness. There has therefore been interest in co-locating loads with existing generation instead of going through a lengthy load integration process.[12] PJM has cited nearly 8.5 GW of large loads (including data centers) that have requested to interconnect in co-location arrangements with existing generators.[13] Co-locating load with existing generation could avoid the need for time-consuming network upgrades prior to connection, but raises a variety of questions (such as cost allocation) that are beyond the scope of this report. Co-location of new loads with existing generation also exacerbates PJM's resource adequacy concerns and can cause transmission reliability issues by effectively adding new large load without a corresponding increase in local supply or transmission capability.

9 PJM's 2025 load forecast report estimates winter peak load to grow at an average of 3.8% annually over the next 10 years. PJM, Long-Term Load Forecast Report, January 24, 2025

10 Josh Saul, Data Centers Face Seven-Year Wait for Dominion Power Hookups, Bloomberg News, August 29, 2024

11 PJM, 2024 in Review: Maintaining an Adequate Generation Supply, January 9, 2025

12 In November 2024, FERC rejected a proposed amendment to an interconnection service agreement for Talen's Susquehanna power plant in PJM, which sought to increase the transfer capacity to a co-located data center, and to recognize the co-located load as fully behind the meter and not "network load". *PJM Interconnection, L.L.C.*, 189 FERC ¶ 61,078 (2024), *reh'g denied*, 191 FERC ¶ 61,025 (2025). FERC also held a technical conference on co-location on November 1, 2024. See note 1 above; see also e.g., Google, Post-Technical Conference Comments, Large Loads Co-Located at Generating Facilities, FERC Docket No. AD24-11-000, December 10, 2024, p2-3. In February 2025, FERC issued a show cause order directing PJM and its transmission owners to demonstrate why the existing tariff provisions are adequate for managing co-location scenarios. *PJM Interconnection, L.L.C., et al.*, 190 FERC ¶ 61,115 (2025).

13 Frederick S. Bresler, Statement on Behalf of PJM Interconnection L.L.C, Co-Located Load Technical Conference, FERC Docket No. AD24-11-000, November 1, 2024.

We focus on a different co-location use case: new large loads that are co-located with new generation.[14] By balancing new load with co-located new supply, integration of the large load is facilitated both in terms of the transmission network (for quicker interconnection) and the resource adequacy impact.

The idea of new large loads co-locating with new generation is gaining interest, as highlighted by President Trump at the World Economic Forum in Davos, Switzerland in January 2025.[15] PJM likewise outlined potential co-location arrangements for this use case that could lead to more timely interconnection while bringing to PJM additional capacity to address resource adequacy challenges.[16] In venues across the country, the pros and cons of "bring your own capacity" requirements and incentives have been circulating.[17]

In this report, we describe a cohesive process to study the integration onto the grid of new co-located generation and load at a single facility (including a control mechanism that limits net bi-directional grid flows), and we assess whether the approach can accelerate the connection process. We refer to the composite facility as an "Energy Park," and propose that PJM implement an Energy Park Integration (EPI) study process to make possible the timely

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[14] We focus on Energy Parks connected to the transmission system, which have different interconnection considerations relative to systems connected to lower-voltage distribution facilities. Transmission facilities tend to have higher voltages (e.g., above 100 kV) and operate in a networked rather than radial topology, among other differences.

[15] Argus Media, Trump touts off-grid gas, coal for AI data centers, January 24, 2025; Both the current and former presidential administrations have encouraged co-location of planned data centers with new energy infrastructure to rapidly build out AI infrastructure. See e.g., Department of Energy, Request for Information on co-locating data centers on federal sites for rapid construction with in-place energy infrastructure, April 3, 2025; White House Archives, Executive Order on Advancing United States Leadership in Artificial Intelligence Infrastructure, January 14, 2025.

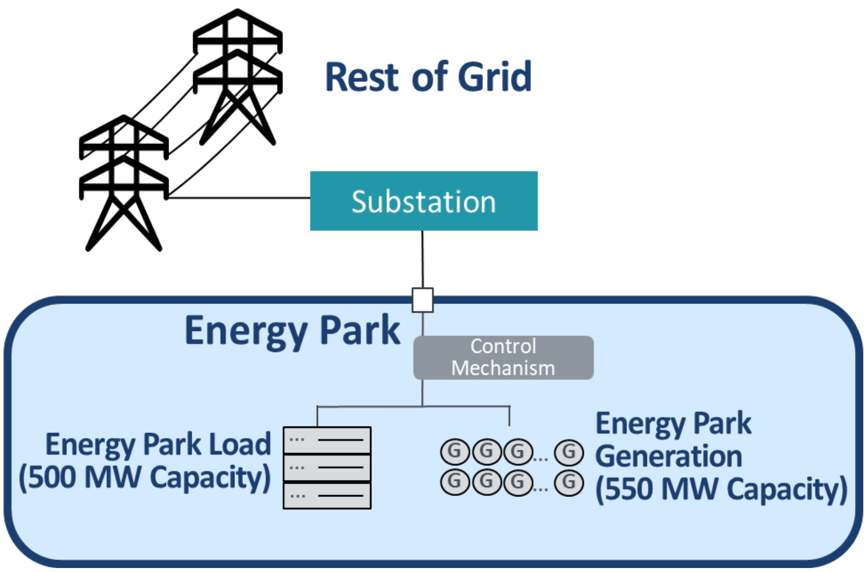
[16] PJM Answer, "New Option 6" on p 17-18 and in Exhibit B. PJM has said it can explore incentives to offer "faster processing of generation that enters the queue through this option" including through "accelerating interconnection studies of new generation" proposed under this option.

[17] For example, New Jersey Assembly Bill 5564, introduced on April 10 2025, which requires that new AI data centers arrange for new energy supply; "The addition of large data centers would be easier if the data centers brought new generation to the market in addition to new load."; Utah Senate Bill 132 allows large loads such as data centers to directly procure power from a co-located generation provider if the local utility and load customer cannot agree a contract within 90 days; Post-Technical Conference Comments of PJM IMM, Co-Location Technical Conference, at 3; "Pennsylvania could encourage—or require, if necessary, through carefully drafted and structured legislation—new large loads such as data centers to BYOG rather than draw from existing generation supply," Exelon, Comments in Technical Conference on Resource Adequacy in Pennsylvania Docket No. M-2024-3051988, January 9, 2025.

interconnection of the co-located new loads and new generation within such Energy Parks and derive benefits for reliability and other consumers. [18]

As illustrated in Figure 1 below, we define the Energy Park as new generation and load that is co-located behind the same grid connection, together with controls and protection mechanisms that can limit maximum flows into and out of the Energy Park. [19]

FIGURE 1: ENERGY PARK CONCEPT



The EPI study approach shares some traits with the approach PJM labeled "New Option 6" in an Answer to FERC's recent show cause order regarding load co-location. Of the new potential options described in the PJM Answer, New Option 6 is the only one that applies to co-location with new generation, as opposed to existing generation.[20] PJM describes New Option 6 as a "Bring Your Own Generation (BYOG)" approach for interconnecting new co-located generation and load more quickly. However, New Option 6 envisages firm Capacity Interconnection Rights (CIRs) for the full output of Energy Park generation, and Network Load status for all of the load, and utilizes separate processes for load integration vs. generator interconnection. Because

18 The concept of 'Energy Parks' has been described in the literature referring to co-located load and generation behind a single Point of Interconnection (POI). Energy Innovation Policy and Technology LLC, Energy Parks: A New Strategy to Meet Rising Electricity Demand, December 2024.

19 For example, the physical principles supporting such protection mechanisms have been described in Schedule F, Part E of the amended Interconnection Service Agreement (ISA) between Talen and PJM submitted to FERC in June 2024 [FERC Docket No. ER24-2172-000] and cited by Commissioner Phillips in his dissent on the Talen ISA decision in FERC on November 1, 2024.

20 *See* Exhibit A, PJM Answer.

PJM's proposed New Option 6 involves an interconnection queue request for CIRs for the entirety of the energy park generation, the study process will test the network's ability to deliver the full output of the generation to all PJM load (ignoring the energy park load unless conducting an EPI-style approach), despite the intent of the generation to inject only a non-firm basis, and to self-supply resource adequacy only at the same grid connection point as the load. In the example shown above, the 550 MW fleet of many small energy park generators meets all of the firm resource adequacy needs of the 500 MW energy park load without any PJM transmission; however, as shown below, the generation may not be able to deliver any capacity to the rest of PJM, for example in the case that the transmission network is fully committed to deliverability associated with CIRs of other, unaffiliated generators. In contrast, the proposed EPI process allows for non-firm net injections and non-firm net withdrawals, recognizes the ability of the energy park to self-supply energy and capacity, and studies the energy park in light of the self-balancing effect of co-located generation and load, reducing the estimated network upgrades and time required to connect the Energy Park.

Precedent for the practicality of the proposed EPI approach exists in the interconnection process for Private Use Networks (PUNs) in the Electric Reliability Council of Texas (ERCOT), which models the PUN as a composite of both load and generation. It is also reflected in a pending proposal in ERCOT regarding interconnection of other non-PUN co-located large load arrangements.[21]

In the following sections, we describe the EPI studies, show how they accelerate energy park connection time and cost by reducing upgrades, and identify the reforms needed to achieve the benefits of EPI studies. We also highlight how EPI study reform can contribute to addressing the resource adequacy strain faced by PJM and reduce bill impacts for all consumers from growth in large loads.

[21] ERCOT, NPRR1234 and PGRR115: Overview, Key Concepts, and Impact to the Generation Interconnection Process, June 12, 2024, p10

II. Energy Park Integration Is a Practical Way to Quickly Connect Large Loads with Fewer Transmission Upgrades

As shown below, because an Energy Park locally supplies all or part of its load, it can be connected to the grid with fewer transmission upgrades (and thus more quickly) when it is studied as an integrated unit. By contrast, using the existing separated processes to study the new load component of an Energy Park (without recognizing the co-located generation) while studying the new generation (without recognizing the co-located load) will ignore these self-supply benefits and overstate the necessary transmission upgrades, slowing down interconnection and unnecessarily increasing costs.

The proposed EPI approach models the composite behavior of load and generation in an Energy Park by accounting for its three essential components: generators, load, and a control mechanism that limits net exchanges with the grid.

For example, as shown in Figure 1 above, consider an Energy Park with 500 MW of load; on-site primary generation totaling 550 MW of installed capacity (e.g., composed of approximately 1,700 individual generation units of 325 kW each to ensure high availability for on-site supply in case of maintenance or other unit outages, such as Bloom Energy's 325 kW individual Energy Server systems); and a control mechanism that limits net grid withdrawals to less than 340 MW and (non-firm) net grid injections to less than 50 MW. The EPI study approach would model both the Energy Park generation and load online in the base load study case. Studied net load impacts would be limited to just the maximum net grid withdrawal at the Energy Park (340 MW net withdrawal in the example), while assessed net injection impacts from the generation would be limited to the maximum possible injection level (50 MW).

By contrast, if today's studies are performed separately on the generation or load component in isolation, they will analyze reliability needs to accommodate up to 500 MW of withdrawals from the grid and 550 MW of injections into the grid, as highlighted in the New Option 6 requirement that a co-located generator have firm CIRs. In other words, the integration study of the Energy Park load would have no mechanism to simultaneously consider the co-located Energy Park generation (which would be represented in a separate process, the PJM generation interconnection queue), leading PJM to model a 550 MW base case injection and the transmission owner to model a 500 MW base case withdrawal. The current co-location studies described by PJM (load integration, do no harm, generator interconnection, etc.) are not set up to coordinate outcomes for the separate components they study, this obstructing the ability of any process to study the injections and withdrawals levels on the lower net basis (which relies on successful integration outcomes for all processes), rather than on the gross.

The above aptly captures the intuition behind PJM reliability study cases. One needs to recognize, however, that transmission reliability needs are often driven by "contingency" studies, which are less intuitive. In the next section, we therefore step through the standard contingency studies used for load reliability planning to show that the proposed EPI study approach yields lower transmission impacts even considering the contingency cases used in transmission planning. These also show the role of the control mechanism in reducing such transmission impacts.

A. EPI-Based Contingency Studies Reduce Transmission Impacts and Interconnection Time

To assess the effect of the EPI approach on transmission upgrades, we evaluate several contingency study cases using an expanded example of the Energy Park shown in Figure 1 above. The EPI approach is an integrated connection process relying on specified maximum net withdrawals (and, if applicable, net injections). Relying on a set configuration that has been submitted by the EPI customer, and which can only be changed under prescribed protocols, the EPI study process assesses different cases for net withdrawals (as load) and the net injections (as generation). For the net load/withdrawal cases, the EPI process conducts **general reliability studies** (like those used in the transmission owner load integration studies).[22] For the net injection/generation cases, the EPI process **assesses non-firm net injections** using a process similar to that used to study Surplus Interconnection Service (SIS) or CIR replacement. This non-firm injection assessment recognizes the secondary purpose of energy park net injections,

[22] PJM planners conduct different categories of studies: general reliability is ensured through test cases including the P0 through P7 events described in the North American Electric Reliability Corporation (NERC) standard TPL-001; congestion is limited through a suite of generator deliverability cases; and zonal adequacy is ensured through load deliverability studies. We use general reliability study cases from TPL-001 to illustrate the effect of the EPI approach on the potential for thermal overloads in contingency cases, including those in the generator and load deliverability studies. In addition to thermal studies, planners study voltage, stability, and short circuit effects of interconnection. Our findings apply to some extent to voltage results, but do not apply to the short circuit or stability studies for Energy Parks, which are not frequent causes of the major transmission upgrades that delay load interconnections.

which do not need to be deliverable and can be limited operationally to only those intervals in which the grid is available to accommodate them.[23] Energy Park customers that wish to request more firm generation interconnection service can make requests for CIRs.

The EPI grid injection assessment captures the intent of the Energy Park in this example to inject onto the grid and make wholesale sales of energy on a non-firm, as-feasible basis (i.e., similar to today's Energy-only interconnections, but even less firm). In our Energy Park example, these injections are illustrated up to 50 MW, as reflected in the EPI injections base case shown in Figure 2 below. [24] By allowing non-firm injections only when the grid is available, the system operator can take advantage of the reliability benefit of the Energy Park's injection capability to the extent the system needs it and can reliably accommodate it, without needing to undertake costly transmission upgrades.

To illustrate the interaction of the Energy Park with the broader grid, the example assumes that the Energy Park and a nearby 170 MW unaffiliated generator form the local grid area, which is connected to the broader PJM grid by two 170 MW transmission lines. The two transmission lines and the nearby unaffiliated generator play an important role in contingency analysis. The transmission lines equally split the net flows between the rest of PJM and the local grid. For example, in the net injection base case shown in Figure 2, the local grid area shows a 50 MW net injection from the Energy Park with the nearby unaffiliated generator offline, together causing a 50 MW total outflow on the interface to the rest of the grid (25 MW over each of the two transmission lines).

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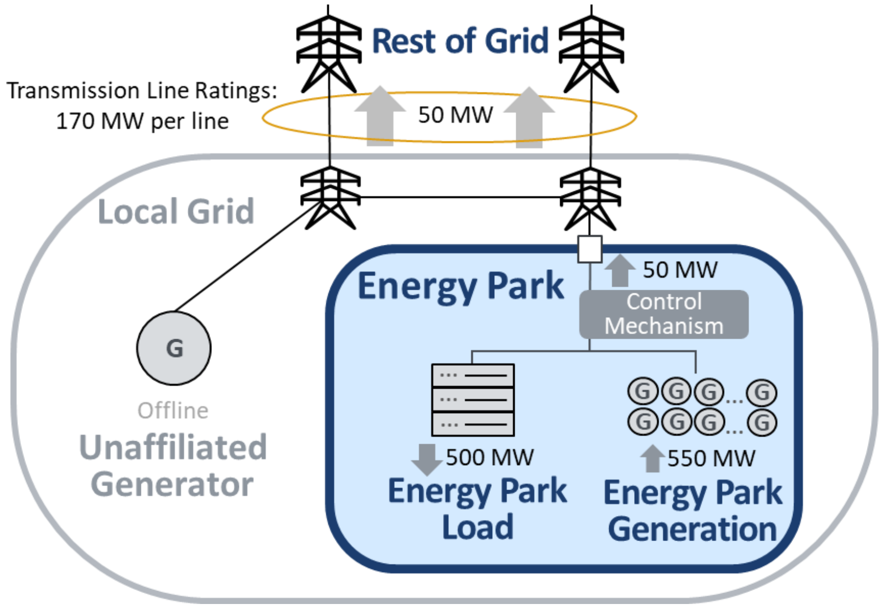
23 PJM and the other U.S. RTOs lead the world in the use of the Security Constrained Economic Dispatch (SCED) mechanism to manage congestion in real time, ensuring all generator dispatches are consistent with reliability via N-1 security given the actual operational configuration of the grid, so that dispatched injections cannot be inconsistent with thermal and voltage security on the grid. Therefore, PJM can limit the assessment of the uniquely non-firm net injections of energy parks to studies that do not have any associated deliverability, without introducing concerns about unreliable injections in operations. Such studies would be set to zero MW in the summer peak case (like today's Energy-only interconnection requests), but also set at zero MW in the winter peak case and the light load case (unlike Energy-only requests). To cover reliability needs not secured by SCED, the Energy Park injection assessment should include a short circuit study, a stability study where necessary, and a local connection study for the physical interconnection point and the immediate electrical vicinity.

24 Today this would be effectuated with an Energy-only interconnection request to the interconnection queue for 50 MW, with zero MW of requested CIRs. The control mechanism described below can be used to prevent any injections above 50 MW if necessary for the purposes of generation injection studies.

FIGURE 2: EPI INJECTION BASE CASE STUDYING NET GENERATION WITHOUT CONTINGENCIES



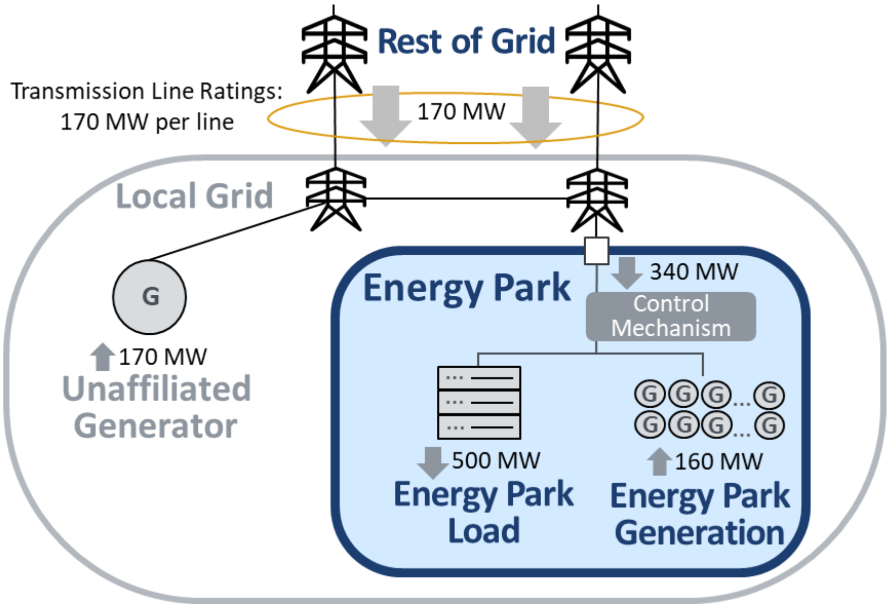
Note: To study a net injection, the Energy Park generation is assumed to operate at maximum output. The Energy Park's generation is competing with the unaffiliated generator for 170 MW of export capability from the local grid; because the RTO is assumed to operate with N-1 security, the local grid can only flow 170 MW to the rest of grid (not the full 340 MW rating of the two transmission lines); the Energy Park therefore cannot inject when the entire 170 MW unaffiliated local generator clears and is dispatched in the energy market. This is consistent with the Energy Park's assumed non-firm injection service.

For simplicity, the illustrated Energy Park does not apply for firm CIRs, which would require the full generation deliverability studies PJM undertakes for resources in its interconnection queue.[25] Rather, the 50 MW injections are non-firm as illustrated in the case above.

For EPI reliability studies of Energy Park withdrawals, the base case example is shown in Figure 3, showing a net withdrawal from the grid of 340 MW (despite the Energy Park's capability to withdraw zero or even net inject 50 MW with its large array of on-site generation).

25 PJM applies a suite of generation deliverability tests even to Energy-only requests, sometimes referred to as "Energy Resources." E.g., "Deliverability requirements for Capacity and Energy Resources are identical except for summer, single contingency conditions where the deliverability requirement is limited to the CIR MW," in PJM, Generator Deliverability Test Modifications: Light Load, Summer & Winter, July 12, 2022 at p. 3.

FIGURE 3: EPI WITHDRAWAL BASE CASE STUDYING NET LOAD WITHOUT CONTINGENCIES



Note: The Energy Park generation in this case is backed down to 160 MW to study a net withdrawal to the Energy Park of 340 MW, reflecting the maximum possible withdrawal. (For cases in which RTO operators can depend on the control mechanism to reduce net flows immediately following contingencies, for instance as a Remedial Action Scheme (RAS), the Energy Park could withdraw up to 500 MW, with the control mechanism limiting withdrawals to 340 MW within seconds (or less) of the first contingency. Note that CAISO allows such RAS arrangements for co-located loads: "If the RAS is designed for new generation interconnection…voluntary interruption of load paid for by the generator is acceptable"; California ISO Planning Standards, February 2, 2023, at page 12)

In this case, the Energy Park's generation supplies the remaining 160 MW to meet the total 500 MW of co-located load. This 340 MW modeled withdrawal from the grid could represent a request by the Energy Park customer for a requested level of grid withdrawal capability to serve load (e.g., occasionally, for economic reasons, despite having the ability to fully self-supply). The 340 MW withdrawal limit imposed by the control mechanism effectively represents an "as available" maximum non-firm withdrawal level that, for reliability reasons, cannot be exceeded at any time.

Table 1 lists the assumptions underlying the stylized Energy Park interconnection.

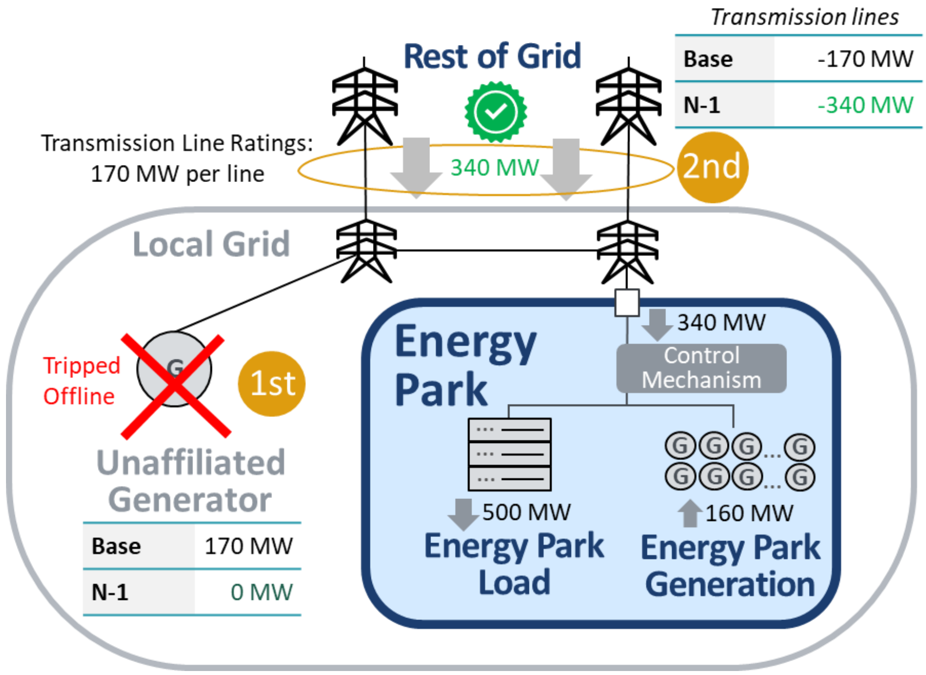
TABLE 1: UNDERLYING ASSUMPTIONS FOR STYLIZED INTERCONNECTION EXAMPLE

Item	Rated Capacity	Base Injection Scenario [Figure 2]	Base Withdrawal Scenario [Figure 3]
Local Grid Area Transmission Interface to Rest of Grid	+/- 170 for each line	+50 (to rest of grid)	-170 (from rest of grid)
Unaffiliated Nearby Generator	170	0	170
Energy Park Generation	550 [composed of many individual units]	550	160
Energy Park Load	-500	-500	-500
Energy Park Net Power to Grid	-	+50	-340
Control Mechanism	-340 to +50	Inactive	Inactive
Capacity Interconnection Rights	0	-	-
Firm Withdrawal Request	170	-	-
Max Non-firm Withdrawals	340	-	-
Max Non-firm Injections	50	-	-

Figure 4 below shows the N-1 "contingency case" for the EPI withdrawal study, reflecting conditions immediately following the loss of the unaffiliated generator.[26] This EPI withdrawal study case for N-1 shows no contingency overloads for this case in which the local grid area has lost 170 MW of supply. As shown, the joint loading over the two transmission lines interfacing with the rest of the grid immediately changes from an inflow of 170 MW to an inflow of 340 MW. All facilities remain within limits while continuing to serve the Energy Park load, so this case would not indicate the need for transmission upgrades.

[26] To avoid system-wide cascading blackouts, transmission networks are operated and planned to ensure they are reliable even after one contingency (i.e., after any one transmission line or generator suddenly fails and trips offline, referred to as an N-1 condition) or after two sequential contingencies (referred to as N-1-1). The N-1 contingency case is comparable to P1 (single contingency) in TPL-001, as well as the N-1 security that is modeled in the generator deliverability tests and that is ensured in operations via SCED.

FIGURE 4: EPI WITHDRAWAL CASE WITH N-1 CONTINGENCY AND NO UPGRADES NEEDED



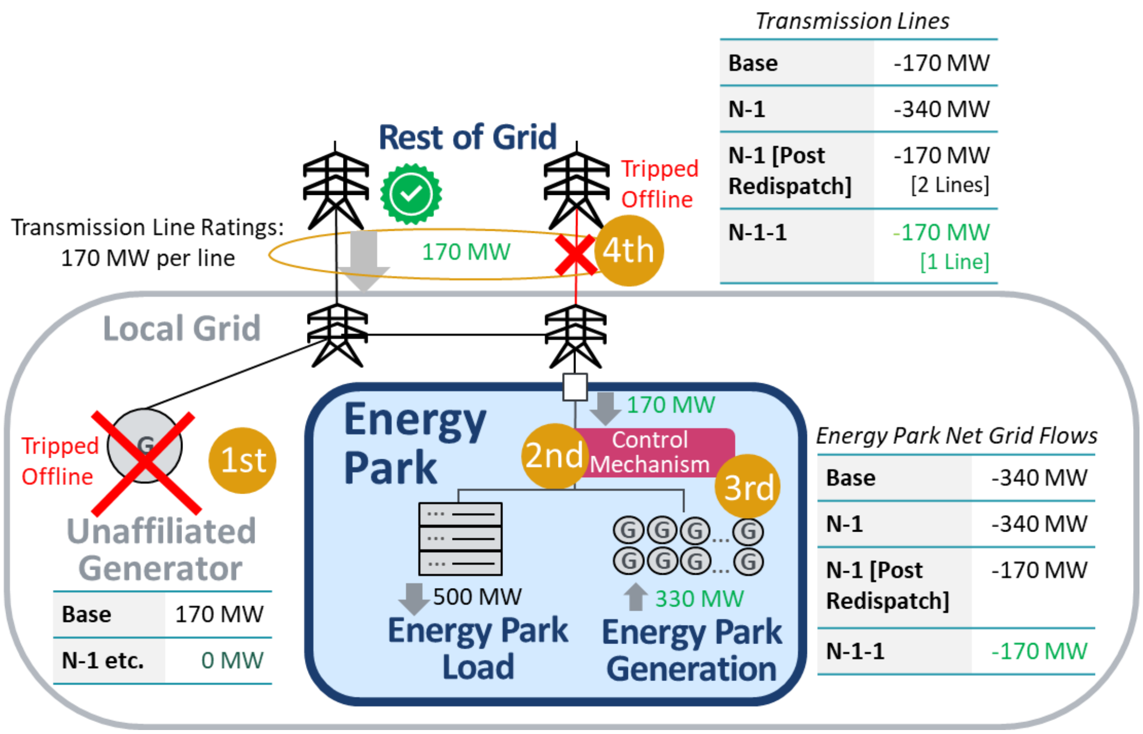
However, the EPI withdrawal reliability assessment is not yet complete, as PJM would also study grid conditions under second contingency, or so-called N-1-1, conditions. The N-1-1 EPI reliability study example is shown in Figure 5 below.

As the example shows, the EPI withdrawal study's N-1-1 (second contingency) case does not show any overloads either due to the "redispatch" action of the Energy Park's control mechanism, which limits Energy Park withdrawals when necessary, such as following a contingency. This unlikely case represents failure of one element of the system (the N-1 case) followed by redispatch, followed later by failure of a second element (creating the N-1-1 case).[27] As before, Figure 5 shows the unaffiliated generator has tripped offline (1st event), but is followed shortly by operator redispatch of the Energy Park to limit grid withdrawals to 170 MW (by rapidly ramping up internal generation to 330 MW), while the unaffiliated generator remains offline. This result depends on a rapid ramp rate from the energy park generation (typical of such resources, especially when configured in an array of small units) and a sophisticated control interaction with PJM, such as provided via its Security Constrained Economic Dispatch (SCED) via the real-time energy market. As shown in Figure 5, this result

[27] The N-1-1 contingency case shown is comparable to P3 (multiple contingency); a similar scenario in which the first contingency is a trip of one of the local grid interface transmission lines is comparable to P6 (multiple contingencies, two overlapping singles) in NERC's TPL-001.

shows that, when one of the two external transmission lines that connect to the local grid trip offline after the unaffiliated generator also trips offline, operations are still reliable, because only 170 MW flows across the remaining transmission line, consistent with its rated in-service capacity.

FIGURE 5: EPI GENERAL RELIABILITY CASE WITH N-1-1 CONTINGENCY AND NO UPGRADES NEEDED



Note that loss of all Energy Park generator units is not shown as a contingency. This is because the Energy Park has configured its on-site generation to use many small, individual units, such that there is no single point of failure. In our experience, such a configuration is typical of data center sites, which could use fuel cells (such as Bloom Energy's 325 kW individual Energy Server systems) or small gas generators as their primary resources.

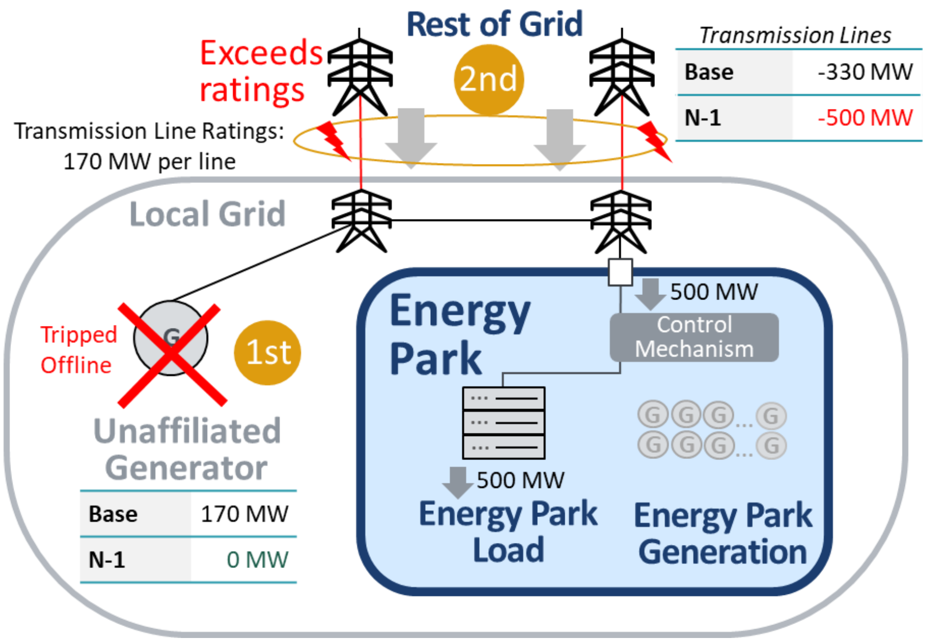
We now contrast the EPI approach illustrated in the previous figures to PJM's existing process, whereby the Energy Park load is studied separately from the Energy Park generation.[28] As explained further in Section III.A below, PJM states that it is responsible for conducting the generator deliverability studies for the Energy Park, while the transmission owner is responsible

[28] This appears to be the case in PJM today for new Energy Parks; for example, Option 6 in PJM's Answer describes new Energy Park generation as being studied in the Queue process while the same Energy Park's new load would be studied in the transmission owner's Load Integration study.

for studying the reliability implications of the load integration. Because of this split in responsibility, and because we are not aware of documented planning case definitions for Energy Parks to the contrary in either of the two processes, we assume the transmission owner load integration studies ignore the Energy Park generation (since the transmission owner could not dependably assume that the on-site generation will be developed and be able to offset grid withdrawals), while the PJM generator interconnection studies ignore the Energy Park Network Load (which would not yet be in the base case). Therefore, the assumed inflows to the local grid area are much higher in the load integration study cases, which use the same type of base case and contingency case definitions as shown above (albeit without the Energy Park generation).

For example, while the base load-only case can serve 500 MW of load, the N-1 load-only contingency case already exceeds the transmission limits and would require network upgrades, as illustrated in Figure 6. This is because 500 MW would be assumed to flow into the local zone to serve the load after the unaffiliated generator trips offline (assuming there is no Energy Park generation nor control mechanism that could limit Energy Park withdrawals), exceeding the 340 MW joint capacity of the two transmission lines. In contrast to the EPI approach, this study result would trigger at least 170 MW of transmission upgrades, delaying interconnection of the Energy Park and potentially adding significant costs that the Energy Park is designed to avoid.

FIGURE 6: CASE SHOWING N-1 CONTINGENCY FOR THE LOAD-ONLY INERCONNECTION STUDY; 500 MW FLOWS OVER EXTERNAL TRANSMISSION LINES, WHICH IS ABOVE THEIR RATED CAPACITY



Note: If a RAS-type control mechanism limiting post-contingency Energy Park withdrawals to 340 MW were considered in the load-only study, this load-only interconnection process would be secure at 500 MW of Energy Park load, as load could be curtailed automatically and immediately (from 500 MW to 340 MW). However, the system would still show reliability violations at the N-1-1 case (after one of the two transmission line trips) unless the load-only study could assume that the Energy Park controller could further rapidly curtail load to only 170 MW during N-1-1 conditions.

These load-only cases illustrate how the presence of the Energy Park generation in the EPI cases helps avoid transmission upgrades, even when severe contingency cases are considered. In a sense, the load-only N-1-1 study is an unrealistic N-1-1-1 study by implicitly taking three elements out of service—the two grid contingencies (already very unlikely) plus all of the hundreds of Energy Park generator units, thus resulting in an excessively conservative planning case. The proposed EPI approach is instead to follow NERC standards and take only two facilities out of service in the N-1-1 planning cases.

A summary table showing the power flows across the different assets and scenarios is provided in Table 2.

TABLE 2: POWER FLOWS ACROSS THE DESCRIBED SCENARIOS

Asset	Rated Capacity (MW)	EPI Process (Net-Load)			Load-only Process (w/o Control Mechanism)	
		Base Case (MW)	N-1 (MW)	N-1-1 (MW)	Base Case (MW)	N-1 (MW)
High Voltage Transmission Lines	+/- 170 MW for each line	**-170**	**-340**	**-170**	**-330**	**-500**
Unrelated Nearby Generator	170	170	0	0	170	0
On-site Primary Generation	550 [composed of many individual units]	160	160	330	Not Considered	Not Considered
On-site Load	-500	-500	-500	-500	-500	-500
Energy Park Net Power to Grid	-	-340	-340	-170	-500	-500
Control mechanism	-340 to +50	Inactive	Inactive	-170 (Active)	Not Considered	Not Considered

The stylized scenarios presented show how the proposed EPI process can unlock accelerated interconnection of Energy Parks with co-located load and generation by avoiding unnecessary network upgrades that would be the result of a load-only interconnection process. While we only consider in detail the study process here for contingencies under general reliability studies, the injection study assessment for the Energy Park modeled with the same EPI approach would similarly yield accelerated interconnection compared to PJM's generator-only interconnection process.

Avoiding unnecessary transmission upgrades provides three important benefits: new large load customers can be connected more quickly; such customers can save on the costs of connection; and transmission upgrade costs that would otherwise be socialized to other customers (which already totals billions of dollars in PJM according to some analysis) would be avoided.[29]

[29] David Lapp, Protest and Comments of Maryland Office of People's Counsel, filed in FERC Docket No. ER24-843, February 9, 2024

B. Experience Elsewhere Highlights the Practicality of Energy Park Integration Studies

Other Independent System Operators (ISOs)/RTOs take an integrated approach to studying Energy Parks, showing that it is a practical option for consideration by PJM and other ISO/RTOs.

For example, ERCOT has an integrated process for connecting co-located load and generation behind a single POI, called Private Use Networks or PUNs. Historically associated with large industrial facilities, ERCOT defines a PUN as "an electric network connected to the ERCOT Transmission Grid that contains Load that is not directly metered by ERCOT (i.e., Load that is typically netted with internal generation)."[30] PUNs can act as both net load and net generation. Recently, there has been interest in establishing PUNs from new large loads such as data centers. Generators have also begun pursuing the addition of new behind-the-meter loads in transmission constrained areas such as South Texas. For interconnecting PUNs to the ERCOT grid, ERCOT and the interconnecting transmission owner study the PUN in an integrated process as independent load, independent generation, and a composite of both load and generation.[31] With over 16,000 MW of PUN capacity in ERCOT, a quarter of which has been added in the last decade, the PUN (i.e., Energy Park) interconnection process has proven to be a practical approach for bringing online co-located load and generation.[32]

In addition, in the most recent planning guide revisions awaiting approval in ERCOT for large load interconnection, ERCOT's Large Flexible Load Task Force proposes that new large loads co-located with new generation (that are not registered as PUNs) undertake a single process in which load may be studied as part of the generator interconnection study, instead of separate load and generator interconnection processes.[33]

In response to ongoing interest in co-location, stakeholders in the Midcontinent Independent System Operator (MISO) and PJM have expressed support for an EPI approach that studies both load and generation together in order to fast-track connection of new Energy Parks.[34]

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30 ERCOT, Nodal Protocols Section 2: Definitions and Acronyms, April 1, 2025

31 ERCOT, ERCOT Update to Texas House of Representatives Committee on State Affairs, March 5, 2025, p6

32 ERCOT, PUN Capacity Report, April 14, 2025

33 ERCOT, NPRR1234 and PGRR115: Overview, Key Concepts, and Impact to the Generation Interconnection Process, June 12, 2024, p10

34 For example, in MISO, NextEra Energy Resources submitted a proposal to study co-located load and generation together to accurately identify the system upgrades required for interconnection. NextEra has proposed that

Continued on next page

C. The Benefits of an EPI Approach Are Highest When Energy Parks Can Dependably Transact with the Grid on an As-Available, Non-Firm Basis

The EPI approach avoids transmission upgrades by incorporating the Energy Park's primary generation and control mechanism to meet on-site load and limit withdrawal and injection exchanges with the grid based on available grid capacity, including during contingencies. Operators can therefore take advantage of dispatchable injection capability during times that the system needs the Energy Park's surplus power and can accommodate it, and can serve Energy Park load to the extent it is economically advantageous and reliable. To ensure a reliable system, planners must know that operators can depend on the Energy Park controller to restrict "non-firm" purchases when the grid is not available to facilitate them. For example, during times that the Energy Park described above wishes to withdraw 340 MW from the grid, but grid conditions limit reliable withdrawals to only 170 MW, the Energy Park must dependably self-supply any load in excess of 170 MW (or else curtail the load).[35] By the same token, energy injections from the Energy Park can only be effectuated when grid conditions allow it.

Operational processes and controls are necessary to ensure the ongoing ability of the Energy Park to reduce withdrawals (and injections) when grid capacity is not available. We do not explore these in detail, but they could be achieved through the PJM energy market and SCED dispatch, or through a locally automated response to grid conditions.

The controls for PJM-dispatchable energy transactions and contingency responses would be in place without necessarily making the Energy Park generation a PJM "Generation Capacity Resource." Rather, Energy Park generation would locally supply the load's resource adequacy need, and its control requirements would support the transmission system interactions of the Energy Park (to avoid unnecessary transmission upgrades). Because the load has its resource adequacy needs met locally, it does not add to PJM's resource adequacy requirement, and its

MISO should factor in proposed co-located loads in the generator interconnection queue, by assigning new loads to specific generators, with a generator interconnection agreement conditional on the load showing up. On the load side, Google, in its response to the co-location FERC Docket No. AD24-11-49000, expressed support for a fast-tracked study process for co-located loads in PJM by "studying new co-located load and generation together in an effort to consolidate upgrades and reduce timelines.", p5

35 The PJM Answer acknowledges the role of as-available withdrawals. See New Options 7 and 8 in Exhibit A, PJM Answer.

generation is not necessary to support PJM-wide resource adequacy needs nor does it need to participate in PJM's capacity market.

III. Reforms are Needed to Realize the Speed and Cost-Effectiveness Benefits of Energy Park Integration

A. The Status Quo Does not Achieve the Benefits of EPI Studies

Under current PJM rules, a new generator seeking to connect to the transmission system is studied in the PJM queue. These studies are coordinated with the local transmission owner. At the same time, new load requesting to be integrated in PJM must be studied through a two-step process that involves: (1) a transmission owner retail load integration study that identifies local upgrades required to meet load based on the transmission owner's criteria;[36] and (2) a PJM 'Do No Harm' study in which PJM evaluates if the new load and any transmission owner-identified upgrades will adversely impact the reliability of the transmission system. In some cases, large load additions can also trigger the need for regional transmission expansions, which are handled through PJM's regional transmission expansion planning (RTEP) process.

For co-located generation and load, PJM prescribes separate processes for load and generator interconnection. For example, in PJM's new Option 6 (offering faster interconnection for Network Load that brings its own generation), PJM describes all 4 steps (transmission owner load integration study, PJM 'Do No Harm' study, RTEP, and Generator Interconnection Study) as required for interconnection of the co-located set of facilities (i.e., the Energy Park).[37] PJM does note that "incentives would be explored to offer faster processing of generation that enters the queue through this option [6]" including "providing options for accelerating interconnection studies of new generation proposed as part of this option" and allowing that "states could remove a barrier to entry for investment in large load infrastructure by assuming cost responsibility for transmission upgrades in the Regional Transmission Expansion Plan ("RTEP")

[36] These local system needs are typically in the form of Supplemental Projects; PJM Answer

[37] See New Option 6 in Exhibit A, PJM Answer

pursuant to the State Agreement Approach."[38] While PJM offers no specifics, the EPI approach we propose achieves the goal of faster and lower-cost Energy Park integration by recognizing the benefits of co-located Energy Park loads and generation that avoids the more expansive network upgrades triggered by studies that independently consider the associated loads and generation, without the need to spur incentives by transferring costs to other customers.

An integrated EPI process is also currently not available through the studies a transmission owner must undertake to integrate new loads. As PJM assigns primary responsibility for new load integration to the transmission owners while it is responsible for studying new generators, it is not clear that a transmission owner could use an EPI approach that involves studying the co-located generation, given the risk that the latter might fail to complete the interconnection queue process. If a transmission owner were to undertake an EPI study, it would lack a defined or documented framework given the current division of responsibilities across interconnecting load and generation.

The generator studies used in the PJM queue (referred to as "deliverability" studies, even for Energy-only interconnection requests, also referred to as Energy Resources) do not recognize the controllable, non-firm nature of potential injections from Energy Park generation designed to self-supply of the Energy Park's load. Even Energy-only generator interconnection requests are studied by PJM with stringent reliability criteria, including for light load and winter cases. This may make sense for the injections of today's Energy-only interconnections (for example wind farms), which are primarily designed to inject energy to the grid, and are offered less-firm Energy-only service in recognition of their lower resource adequacy value, rather than the lower business priority associated with their injections. In contrast, in the case of an Energy Park, co-located generation is designed primarily for on-site supply, and would inject energy to the grid only to the extent grid capacity is available or doing so is beneficial to the system. Therefore, Energy Park net injection assessments should reflect the controllable, as-available, non-firm nature of injections from Energy Parks.

For that reason, and because injections would likely be limited (and perhaps infrequent), PJM can limit the assessment injections to those studies that do not have any associated deliverability. Because the Energy Park controller only exchanges power with the grid when it is reliable to do so (for example, by following SCED dispatch), Energy Park injections will not introduce concerns about unreliable operations. Therefore, the EPI injection studies would be set to zero MW in the summer peak case (in the same way as Energy-only MW today) but

[38] PJM Answer, p. 17

would also set output in the winter peak case and the light load case to 0 MW. It follows that, in order to cover reliability needs not secured by the Energy Park controller, the Energy Park injection assessment would include a short circuit study, a stability study where necessary, and a local connection study for the physical interconnection point and the immediate electrical vicinity.[39]

An Energy Park that is controlled only to inject into and withdraw from the grid based on available real-time grid capacity (i.e., with zero firm injection and withdrawal MW) should be presumed in the first instance to have *de minimis* impact on the grid in most cases. Even with some firm withdrawal MW (as in the case of the above example), an assessment of the impact of zero firm injection MWs would be expected to have no impact. In that respect, the assessment process is analogous to PJM's recently-revised CIR Replacement process or the SIS process, both of which offer expedited interconnection processing for new resources as long as screening studies confirm that there are no material impacts on the grid.[40] The analogy holds because both the CIR replacement process and the SIS process contemplate a zero MW net increase in firm injections. SIS allows generators to quickly add new capacity behind existing interconnection points, and CIR Replacement to change the fuel type at or near existing interconnection points, provided total injections remain limited to the level specified in the existing interconnection agreement. This new capacity is fast-tracked through the interconnection queue, using a screening assessment to ensure that accommodating the projects does not require network upgrades. Such an expedited approach could be reasonably adapted to Energy Parks that only seek to transact with the grid on a non-firm basis based on available grid capacity.

The Energy Park control mechanism, which may include physical protection mechanisms to limit maximum flows into or out of the Energy Park, plays an important role in limiting unnecessary transmission upgrades to accelerate interconnection. To achieve these benefits, documentation of technical standards for the control mechanism and physical protection systems is needed so that developers can reasonably anticipate and plan for necessary hardware, and transmission owners can process new connection requests without having to reinvent potentially detailed technical requirements to ensure net withdrawals or injections from the Energy Park remain within the specified range. For example, PJM has acknowledged and allowed the use of such physical protection mechanisms in approving Talen's amended

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[39] We note that a co-located generator would have the option to seek a higher level of injection "firmness" by requesting Energy-only or CIR status, leading to more robust interconnection studies

[40] PJM Inside Lines, FERC Accepts Two PJM Proposals To Expedite Supply Additions, February 12, 2025

Interconnection Service Agreement for Susquehanna power plant, but has not established specific requirements.

As discussed above, operational processes and controls are necessary to ensure the ongoing ability of the Energy Park to reduce withdrawals (and injections) when grid capacity is not available. Such tariff and protocol requirements do not exist today, and would need to be added to minimize unnecessary transmission upgrades. With dispatchable onsite self-supply resources—such as fuel cells, gas turbines, or battery storage—it is possible to make the Energy Park's net transactions with the grid dispatchable (up or down) by PJM using the same energy market offer, clearing, and dispatch system already used for other generators. This can be accomplished by allowing Energy Park operators to bid their as-available injections and withdrawals into the PJM market with the requirement to follow PJM resulting dispatches. Transmission planning benefits (i.e., avoiding otherwise necessary transmission upgrades) are maximized through such dispatch because the system operator can rely on the Energy Park to limit injections or withdrawals to the available grid capacity.[41]

Finally, while the focus of this report is on Energy Parks that are able to both withdraw from and inject into the grid, non-injecting Energy Parks that are able to control their net withdrawals offer similar benefits to the grid. We thus propose that load integration studies of such non-injecting Energy Parks should be conducted based on the same EPI framework (without any screening or studies for net injections).[42]

B. Reforms Can Achieve Energy Park Integration Benefits

Given the gaps identified in Section III.A above, the following reforms to the PJM and transmission owner interconnection processes would be necessary to achieve the speed and cost benefits of the proposed EPI process:

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[41] Transmission benefits could be enhanced further if the outage of large individual Energy Park generators (if any) is coordinated with PJM and transmission owner operations. While generators who qualify as Capacity Resources must coordinate their outages with PJM, there are no such provisions for energy-only resources or Energy Parks.

[42] Energy Parks with zero net injections can be incorporated into real time operations (SCED) in the same way as injecting Energy Parks. Load is considered in demand response and that may be the default for Energy Parks that lacks net injection capability, but demand response is not currently integrated into SCED. Incorporating the dispatchability of Energy Parks even if they do not provide net injections can maximize transmission benefits. ERCOT's Controllable Load Resources (CLR) framework provides a precedent for how load resources can be dispatched on a 5-minute basis.

- **PJM and transmission owners**: develop and document EPI protocols for Energy Parks, as an alternative to the currently applicable separate study processes, including the PJM generator interconnection study process, the PJM 'Do No Harm' study, transmission owner load integration study, and (in limited cases) the PJM regional transmission expansion process (RTEP). The EPI protocols would need to include provisions for coordination between separate study processes (unless the relevant parties integrate them into a single process).
- **PJM**: allow for non-firm grid injection requests based on "as available" grid capacity (i.e., less firm than current Energy-only interconnections). Study these non-firm Energy Park injections through an expedited screening process similar to that of PJM's new Surplus Interconnection Service (SIS) or Capacity Interconnection Rights (CIR) replacement processes, given that non-firm net injections by the Energy Park can be controlled automatically so they will not cause transmission impacts beyond the designated levels.
- **PJM and/or transmission owners**: Document technical standards for the Energy Park controls and protection mechanisms used to limit physical withdrawals and injections between the Energy Park and the grid to the pre-specified amounts. Develop provisions to ensure that PJM and transmission operators can rely on the Energy Park to control net injections or withdrawals when grid capacity is limited (during contingencies) in real time operations.

IV. Energy Park Integration Reform Could Alleviate Resource Adequacy Strain

PJM is experiencing unprecedented resource adequacy challenges in large part due to rapid load growth, largely from new data centers and other large loads requesting to be integrated to the grid.[43] PJM's 2025 load forecast report estimates winter peak load to grow at an average of 3.8% per year over the next 10-year period.[44] The consumer impact of high capacity prices driven in part by load growth has been a subject of particular concern.[45]

Large load customers are motivated to accelerate the timelines to integrate their new facilities, generally prioritizing speed over reducing the cost of their power supply, given the high profitability and robust demand for these services.[46]

The EPI process proposed in this report is not meant to apply to Energy Parks that are planned to include only backup generation (such as diesel generators) that would operate only in cases where the grid connection is lost. Diesel backup generation, as discussed above, is limited by the number of hours they can operate due to air pollution permitting requirements.[47] Instead, the proposed EPI reforms are meant for Energy Parks in which the embedded new generation is designed to be able to serve the embedded new load during normal operations.

An accelerated EPI process would provide an appealing mechanism to incentivize developers of new large loads (such as data centers) to serve their loads with new co-located primary generation resources in return for faster online times and reduced grid interconnection costs. To achieve this, these customers could enhance their on-site generation plans from back-up only (typical today) to inclusion of primary generation technologies capable of self-supplying

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43 PJM Inside Lines, 2024 in Review: Maintaining an Adequate Generation Supply, January 9, 2025; NERC, 2024 Long-Term Reliability Assessment, December 2024; American Public Power Association, PJM CEO Voices Concerns About Resource Adequacy, October 23, 2024.

44 PJM, Long Term Load Forecast Report, January 24, 2025.

45 Governors of Illinois, Maryland, Delaware, New Jersey, and Pennsylvania, Letter to the PJM Board, dated October 25, 2024

46 Center for Strategic & International Studies, The Electricity Supply Bottleneck on U.S. AI Dominance, March 2025.

47 See for e.g. Northeast States for Coordinated Air Use Management, Air Quality, Electricity, and Back-up Stationary Diesel Engines in the Northeast, January 2014.

their load on an ongoing basis in normal operations (e.g., through a combination of gas turbines, fuel cells, batteries, and/or renewable resources).

New off-site capacity therefore does not have to be planned to meet load at an Energy Park to the extent that co-located generation offsets capacity for co-located load. Given the predominance of large load customers in the load forecast, and the breadth of those customers that could benefit from the EPI study approach, this could have an outsized effect on mitigating PJM's current resource adequacy challenge.

This EPI process would also allow new loads to be added at sites where new generation could be developed from a permitting perspective, but is not possible in a timely or cost-effective fashion due to grid constraints.

By incentivizing new customers to largely or fully self-supply their own load, grid expansion and resource adequacy challenges are reduced. The consumer bill impacts of large load growth would likewise be mitigated. New generation resources that are brought online through an EPI process could then also have the option to sell surplus generation to PJM, which would further reduce PJM's supply challenges.

V. Conclusion

We have described an EPI process that can accelerate the integration of Energy Parks consisting of co-located load, primary generation, and a control mechanism that regulates grid withdrawals and injections. We illustrate with stylized N-1 and N-1-1 contingency scenarios how EPI studies allow grid planners to leverage an Energy Park's generation and control mechanism that limit net withdrawals to those serviceable by the grid with minimal upgrades. We identify the reforms necessary to enable new large loads and co-located generation to interconnect quickly under the EPI framework. Namely: establishing EPI protocols; clarifying the role of the grid operator and transmission owners; allowing for an expedited study process and assessment protocol that reflects the lower expected grid impact of Energy Parks; and integrating the dispatchability of the Energy Park's assets in real-time operational frameworks (SCED or otherwise) to maximize their benefits for grid reliability and economic dispatch of available resources. An accelerated interconnection process under the EPI framework offers the opportunity to support federal and state priorities on data centers, manufacturing, and artificial intelligence infrastructure and addresses critical challenges with resource adequacy and grid upgrades. In particular, the benefits of the proposed EPI framework are as follows:

ACCELERATES INTERCONNECTION OF NEW LOAD AND NEW GENERATION

Eliminating network upgrades through controllable Energy Parks can immediately reduce large load interconnection lead times by eliminating the need to pursue lengthy new transmission builds that need to be brought online prior to energizing the new load. Under the currently available processes, a large new load might wait for years until transmission expansion (planning through a local or regional transmission planning process) is online. Similarly, a new generator meant to serve the new load would be delayed through the existing multi-year generation interconnection queue process. By co-locating new load with new generation and acknowledging their controllable grid interaction (self-balancing with maximum withdrawal or injections) in the study process, time consuming and expensive network upgrades are avoided, expediting the process for bringing these resources online and supporting federal and state priorities at lower cost.

SUPPORTS RESOURCE ADEQUACY AND ENSURES MORE EFFICIENT USE OF THE EXISTING NETWORK

By offering expedited integration of co-located new loads and new generation through the EPI framework, grid planners incentivize new loads to bring their own generation. This has multiple benefits. First, the dispatchable new Energy Park generation serves the resource adequacy needs of the Energy Park load, mitigating PJM's resource adequacy challenges. This can be enhanced further for Energy Parks with excess supply that can inject onto the grid during system peaks or emergencies in coordination with the grid operator, potentially serving system load during scarcity events. Second, the EPI framework utilizes existing grid capacity more efficiently because the Energy Park's generation can be controlled to supply the co-located load whenever doing so is necessary to limit the Energy Park's withdrawals or injections to the available grid capacity. Thus, the need for network transmission upgrades to serve grid withdrawals by new load or non-firm injections by new generation is greatly reduced or eliminated.

REDUCES CONSUMER BILL IMPACTS FROM LARGE LOAD GROWTH

By avoiding unnecessary transmission upgrades to accommodate new large loads, the EPI process avoids any costs that would otherwise be allocated broadly to all customers. By facilitating and accelerating a "bring-your-own capacity" approach, the proposal mitigates the resource adequacy impact of load growth, easing price increases in the capacity market and the commensurate bill impacts for all consumers.