Comments on Reliability Resource Initiative
MN8 Energy
November 26, 2024

Introduction

MN8 Energy (formerly Goldman Sachs Renewable Power) is a developer, owner, and operator of solar and battery energy storage projects across the US, with over a dozen operating projects in PJM today and many more under development in the queue. We thank the PJM Staff and Board for their time and the opportunity to submit comments.

PJM is putting forward the Reliability Resource Initiative (RRI) as a necessary solution to meet medium-term resource adequacy (RA) needs. However, to solve these needs, its primary focus should be on maximizing the unforced capacity (UCAP) that it gets out of the existing queue.

According to PJM, there is up to 44.5 GW UCAP available from projects currently in the queue.[1] In support of bringing this UCAP to market, PJM should pursue a set of policies that minimize project attrition from the queue.

As PJM thinks about success, it must bear in mind that bringing online timely resource adequacy is not just a matter of timely energization of projects; it also requires that these projects are deliverable, or in other words, are not waiting on long-lead time contingent network upgrades (NUs), which would undermine their ability to deliver timely UCAP.

Risks Posed by Generator Deliverability Test Transition

PJM recently made changes to its generator deliverability (GD) test to update its modeling approach and assumptions used in generator interconnection studies.[2] These assumptions are what ultimately drive the identification of violations and therefore NUs in interconnection studies. Without intervention by PJM, this transition risks an unfair cost shift that would increase attrition rates for Transition Cycle 2 (TC2) and RRI projects, in addition to extending timelines for contingent NUs, and thus, project deliverability.

Projects that were studied in the legacy Serial Process, Expedited Process (or Fast Lane (FL)), and Transition Cycle 1 (TC1) were all studied using models that used the legacy GD test to model generation. The violations observed and NUs assigned were all based on how resources performed under these legacy assumptions.

Beginning with TC2, all future requests will be studied using the new GD test. The models used for TC2 studies will also include generators that have already been studied (e.g., existing assets, projects in the FL, and projects in TC1), and these prior generators will also be modeled under the new GD test. Critically, some of these generators will not have been studied under these assumptions previously – neither in the GI process, nor in the Regional Transmission Expansion Plan (RTEP). To the degree that this materializes, the new GD test may find violations where the old one did not, and these impacts may fall to TC2 and RRI projects, neither of which are responsible for causing these violations.

---

[1] Slide 23 https://www.pjm.com/-/media/committees-groups/committees/mc/2024/20241121/20241121-item-04a---1-member-consultation-regarding-reliability-resource-initiative---presentation.ashx
[2] https://www.pjm.com/-/media/committees-groups/committees/pc/2022/20220809/item-05a---generator-deliverability-proposal-summary.ashx

Without TC2, these impacts would eventually make their way to an RTEP case where they would be addressed through the RTEP process. However, if nothing is done, there is a timeline problem where most or all of the impacts caused by FL and TC1 projects may show up first in the TC2 cluster studies, not an RTEP. This could very well result in generator attrition, such that these upgrades fall to load anyway, but not before they cause TC2 and RRI projects to drop out of the queue, undermining entry of new UCAP right when PJM needs it most.

MN8 studied this issue using the same software as PJM and finds that this has the potential to have significant impacts. There are cases where monitored facilities that were not overloaded in the old deliverability test are significantly overloaded in the new test, even before adding TC2 projects. In fact, we analyzed the entirety of TC2 and found that 67% of projects are inheriting at least one network upgrade from a prior cluster.[3]

This analysis isn't perfect, as there are network upgrades that will come through the TC1 study process and/or the ongoing RTEP process that will address some of these violations. However, we have identified specific cases where elements are not overloaded by TC1 projects under the old GD test but are overloaded once moving to the new GD test, *prior to introducing TC2 projects*. The fact remains that some FL and all TC1 generators may never be studied under the new GD process prior to TC2 completion, and we believe that these results indicate that this introduces a material risk that warrants attention. Specifically, with no intervention, TC2 and RRI projects may be allocated costs that they did not cause, which would increase attrition rates at a time when these projects are most needed and introduce additional contingent NUs that risk delays to their deliverability dates.

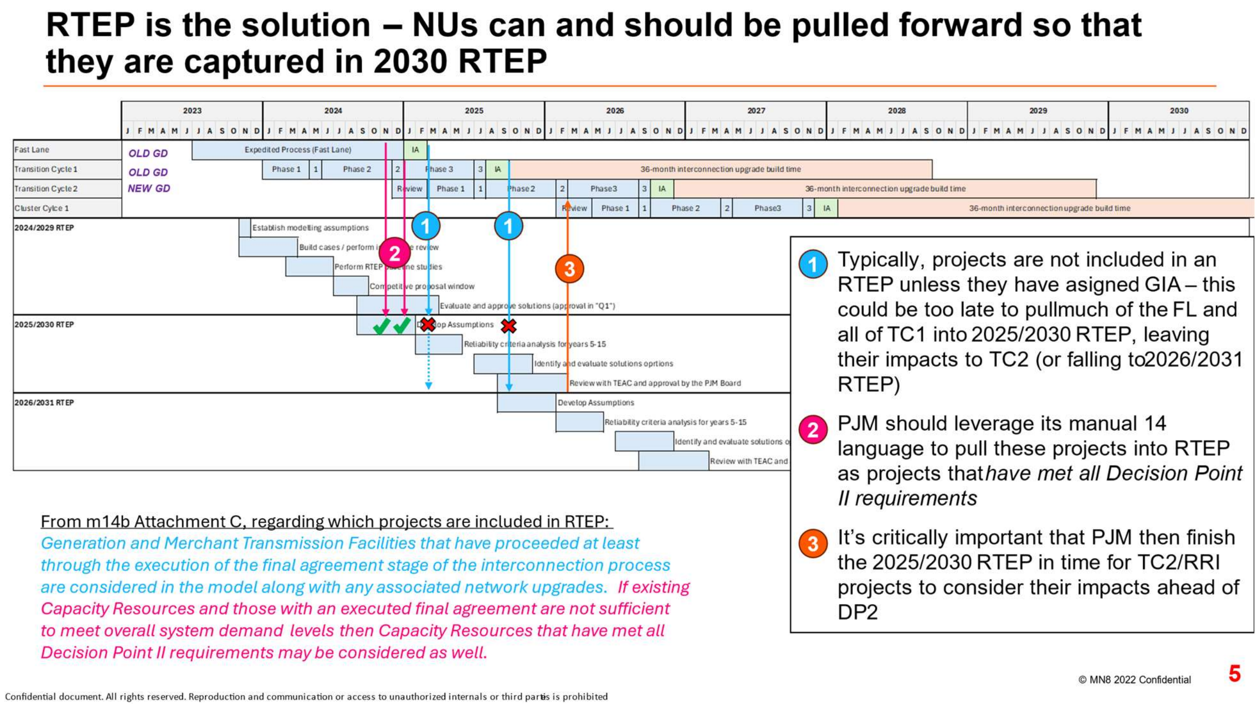
Fortunately, we believe there is a solution that is relatively straightforward, and one that PJM can act on under its existing tariff authority: PJM must ensure that Fast Lane and TC1 projects are studied in the 2025/2030 RTEP.

Typically, projects are only added to an RTEP once they have signed a generator interconnection agreement (GIA). This is likely too late for some of the Fast Lane and all of TC1, which means that any overloads that they cause after moving to the new GD test would fall to TC2 and RRI projects. The blue arrows in the image on Slide 5 of MN8's MC presentation (also included below) indicate the dates when we would expect the last FL and TC1 GIAs to be signed, which occur after the normal timeline for locking in RTEP assumptions vis-à-vis the 2025/2030 RTEP. PJM should leverage the language from Manual 14B to add projects into the 2025/2030 RTEP that "have met all Decision Point II requirements."[4] This would include all FL/TC1 projects, as indicated by the pink arrows on Slide 5.

---

[3] Slide 4 https://www.pjm.com/-/media/committees-groups/committees/mc/2024/20241121/20241121-item-04b---7-mn8-comments-on-rri--sis---presentation.ashx

[4] https://www.pjm.com/directory/manuals/m14b/index.html#Sections/C3_Overview_of_Deliverability_to_Load.html



Finally, it would be critical for PJM to finish the 2025/2030 RTEP in time for the TC2/RRI projects to consider how the results of the RTEP impact their expectations of their ultimate cost allocations. That is, these projects will want to have time to assess whether any upgrades identified in the RTEP will obviate costs they are being allocated in their Phase 2 study results, which these upgrades will not have been factored into. As shown by the orange arrow on Slide 5, the usual RTEP timeline would mean this will come down to the wire, and it's important that PJM accelerate this so that projects have several months to digest the implications of the 2025/2030 RTEP upgrades.

In addition to addressing an unfair cost shift, pulling FL/TC1 projects up into the 2025/2030 RTEP will have timeline benefits. Specifically, doing so will accelerate the completion of NUs by 9 to 14 months, which, assuming a three-year build time, could be the difference between UCAP being available by the 2029/2030 Delivery Year (DY) or being delayed to DY 2030/2031, as shown on Slide 6 of MN8's presentation.

Comments on the Design of the RRI

By adding in new projects to TC2, PJM would be introducing the risk of adverse impacts on projects currently in TC2. Specifically, TC2 projects may face additional NUs that result in increased cost allocation and timeline delays by dint of being studied along with RRI projects. This could have material impacts on the economics of TC2 projects, which might compromise their likelihood of being successfully financed and built, and even if successfully financed and built, lead to a delayed COD due to delayed placed in service (PIS) dates for their contingent NUs. For instance, it is entirely possible that some projects in TC2 may have found a spot on PJM's grid with enough residual transmission system capacity, or "headroom," so that it could interconnect without triggering new NUs, particularly following the introduction of upgrades from RTEPs that were not available to TC1 projects. If an RRI project is being located in approximately the same place, the two projects combined might cause overloads, which both projects would then have to pay for.

We expect that adding a sizable RRI tranche would increase the risk that TC2 projects have costly, long-lead time NUs. These additional costs are material to the development expenses for a new project, and may cause a project to drop out of the queue. Delays to a project's COD can also be material to a project's viability. Namely, projects typically need a PPA in place before they can reach Final Investment Decision and proceed with construction, and under many off-take agreements, projects experiencing delays are penalized. For example, we recently modeled a battery energy storage project in another competitive market that, if delayed by even one year, would see a substantial decline in its IRR due to penalties from delays associated with undelivered capacity, which in this case would cause it to miss its investment hurdle rate. The possibility of a delay to this project risks deterring our decision to proceed with the project.

In addition to higher cost allocations for interconnection and delayed in-service dates, policies like RRI can impact the financing costs for projects. This is an important consideration for the competitive marketplace, where financing parties consider the prevailing regulatory risks as a key factor when determining financing rates. This means that policy decisions—and even the looming risk of policy decisions—can impact the cost of doing business in a given market. For example, hurdle rates for equity sponsors may vary materially from one market to the next due to regulatory risks, at times by one or two percentage points, which leads to substantial differences in financing costs.

By introducing risks like higher NUs, later in-service dates, and greater regulatory uncertainty, RRI may have the opposite effect of what's intended, reducing the amount of capacity that can economically enter the PJM market in the medium term, and increasing the cost of doing business in PJM in the longer term.

PJM should hold TC2 harmless for adverse impacts caused by the addition of RRI projects by allocating additional costs to RRI projects specifically. PJM can protect TC2 projects from NU cost impacts with two adjustments to its current proposal:

1. Parse out impacts related to TC2 projects alone versus TC2 and RRI projects together in interconnection studies. This can be done with minimal incremental time or effort and may even be possible to do in just one model run.[5]
2. Determine NUs for TC2 projects first, solve cost allocation for TC2 projects alone, and then solve NUs needed for TC2 and RRI projects together, with incremental costs being allocated to RRI projects. By sequencing the work in this way, PJM will only retool NUs for TC2 projects where an RRI-triggered violation would introduce the need for additional upgrades. We expect the time and effort to come up with these RRI-triggered NUs to scale with the number of RRI projects. Because PJM and Transmission Owners (TOs) will be responsible for determining NUs for all TC2 projects regardless, we would not expect the approach described above to take more time than if PJM and TOs determined NUs for TC2 and RRI projects separately.

[5] PJM should prioritize implementing this approach for thermal impacts observed under power flow studies.

These additional steps can be completed with minimal disruptions to timelines and administrative burden. Undertaking (1) and (2) above would mitigate legal risks, as well as cost and attrition risks to TC2.

Finally, if pursued, we would recommend restructuring the RRI intake process so that it prioritizes projects that can most quickly deliver timely UCAP. The cap should be defined in UCAP terms (versus number of projects) based on the expected RA shortfall. This shortfall should be analytically derived and vetted through an expedited stakeholder process. Projects should be prioritized based solely on in-service date out of recognition that projects that can be online (and deliverable) earlier are more valuable to PJM. Projects that sign a GIA should be required to offer into the BRA beginning with the DY that corresponds to the COD that was offered at the time of intake; failure to do so should result in penalties equal to the price of replacement capacity. Penalties will ensure that offerors are taking measures to ensure project viability while reducing administrative burden for PJM. By making these changes, PJM can greatly simplify its project selection process and select projects that will provide the most timely UCAP.

Comments on Surplus Interconnection Service

PJM should commit to developing a workable surplus interconnection process. Surplus Interconnection Service (SIS) may unlock as many as 7.7 GW UCAP already in 2027.[6] Because SIS can enable new UCAP without allocating additional CIRs, this should be considered low hanging fruit for bringing new RA to market. Further, as ELCCs decline, the potential for SIS to enable more RA will only increase. Tariff changes are a good start; we encourage a timely stakeholder process to develop manual language. This manual language should include:

1. A workable material adverse impacts standard that approves surplus requests that do not trigger network upgrades,[7]
2. A study process that does not inadvertently result in queue jumping,[8] and
3. Improved study assumptions for how storage is modeled.[9]

All of these improvements will support the efficient entry of new UCAP in the medium and long term.

---

[6] https://acore.org/resources/resisting-a-resource-shortfall-fixing-pjms-surplus-interconnection-service-sis-to-enable-battery-storage/

[7] PJM should also work with stakeholders to ensure that its materiality thresholds and request cure processes are consistent with best practices from other markets with viable surplus pathways.

[8] Specifically, surplus requests should be studied using models that include *all projects that have already been accepted into a cluster for study*.

[9] Battery energy storage should not be modeled as discharging during the light load study case. Additionally, as required by FERC Order 2023 Paragraph 1509, Interconnection Customers (ICs) should be allowed to propose specific operating parameters for battery energy storage resources to be used in studies. Alternatively, PJM could offer a short menu of options that reflect different operational behaviors or strategies, which would afford ICs more choice and more closely achieve the intent of FERC's Order 2023 mandate.