Duke NICHOLAS INSTITUTE *for* ENERGY, ENVIRONMENT & SUSTAINABILITY

Beyond FERC Order 2023

Considerations on Deep Interconnection Reform

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CONTENTS

Introduction 1
What is Connect and Manage? 3
Deficiencies of Invest and Connect 5
Improving ERIS Service 8
Interaction 8
Modeling 8
Impact Threshold 9
Managing Curtailment Risk 10
Managing Hybrid Resources 13
Linking Interconnection, Transmission Planning, and Procurement 14
Conclusion 16
References 17

INTRODUCTION

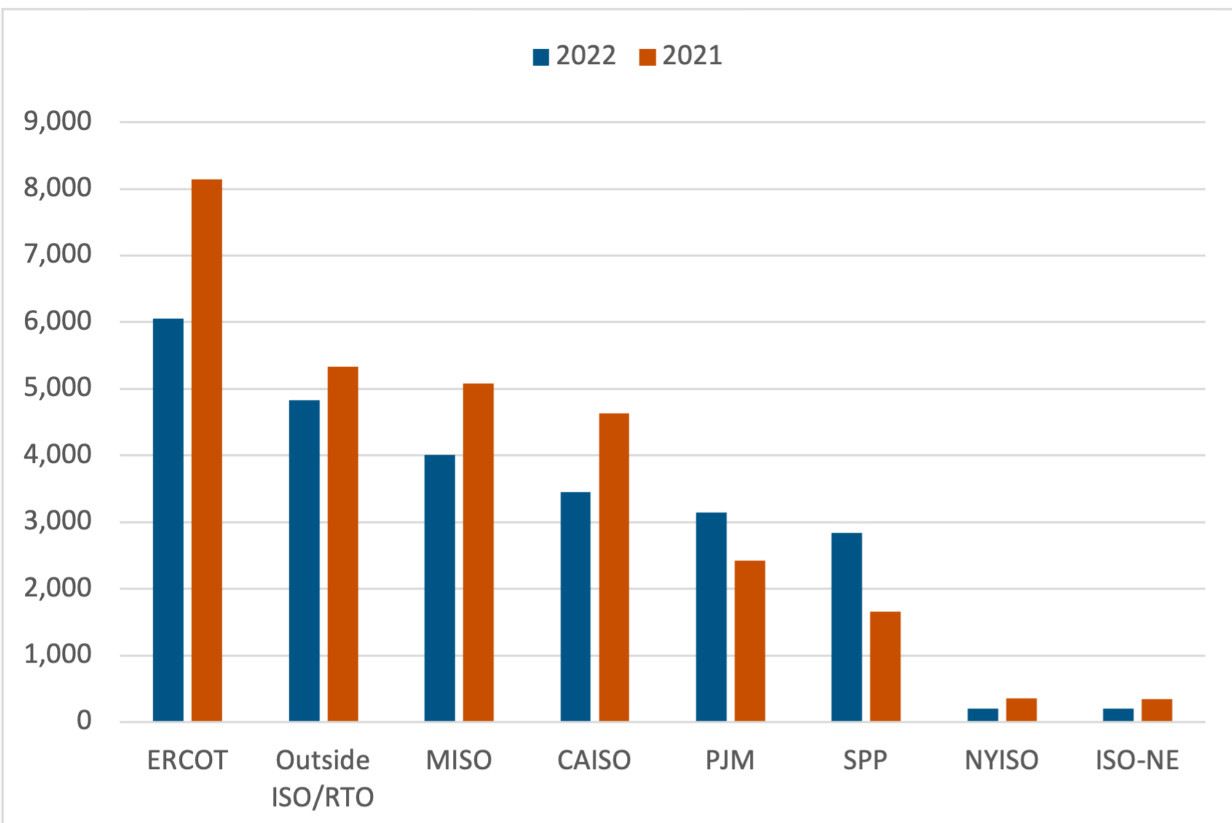
In late July 2023, the US Federal Energy Regulatory Commission (FERC) released its much-anticipated rule on interconnection reform, Order 2023. The purpose of the rule is to address interconnection queue backlogs, reduce uncertainty, and prevent undue discrimination to “ensure that interconnection customers are able to interconnect to the transmission system in a reliable, efficient, transparent, and timely manner” (FERC 2023, p. 3). The rule seeks to achieve these ends with targeted revisions to *pro forma* interconnection procedures that implement a first-ready, first-served cluster study process, increase the speed of interconnection queue processing, and incorporate technological advancements into the interconnection process.

Reactions to Order 2023 have varied, but the evidentiary record identified fundamental interconnection barriers that remain unresolved. As FERC Commissioner Allison Clements noted in her concurrence to the order, “while this rule can be expected to improve matters, more will be necessary to solve the problem… I urge stakeholders to examine these and related suggestions, and for transmission planners to adopt regionally appropriate solutions beyond those required by this final rule” (Clements 2023, p. 3). Other experts have noted that Order 2023’s central reform, which requires the adoption of cluster-based studies, has already been practiced in some markets with unclear results (Howland 2023).

The purpose of this paper is to consider deeper reform to accelerate the pace of interconnection and reduce network upgrade costs. Specifically, this paper examines reform options raised by Commissioner Clements' concurrence: transitioning to a *focused* interconnection process or *connect and manage* approach; linking the interconnection process to proactive transmission planning; and aligning interconnection processes with competitive resource solicitations.

The potential for deeper reform to address the stated purpose of Order 2023 is illustrated by a comparison of two independent system operators/regional transmission organizations (ISOs/RTOs). Between 2021–2022, the Electric Reliability Council of Texas (ERCOT) interconnected 2.5 times more total capacity than PJM (Dlin 2023), despite the fact that PJM is approximately twice as large as ERCOT in terms of peak load (Figure 1). ERCOT's experience suggests that a less restrictive study process could speed the interconnection of resources in a way that can be managed after their integration with the grid, leading to a larger volume of interconnected generation capacity without sacrificing reliability.

Figure 1. Interconnected capacity by US ISO/RTO, MWac



Abbreviations: MISO, Midcontinent Independent System Operator; CAISO, California Independent System Operator; SPP, Southwest Power Pool; NYISO, New York Independent System Operator; ISO-NE, ISO New England.
Source: Data adapted from Dlin 2023.
Note: Outside ISO/RTO regions include the Southeast, Northwest, and Southwest.

This brief:

- Summarizes connect and manage in relationship to existing interconnection procedures and reviews foundational issues with current processes not addressed by Order 2023
- Identifies opportunities to improve energy-only interconnection procedures and potential solutions to manage attendant complications with curtailment risk and hybrid resources
- Discusses linkages of interconnection, transmission planning, and competitive procurement in alignment with a connect and manage approach, particularly in jurisdictions not governed by ISOs/RTOs.

WHAT IS CONNECT AND MANAGE?

To understand connect and manage, it is first helpful to recall the predominant paradigm for large generator interconnection (GI). Outside of ERCOT, most generators seeking to interconnect to the transmission system are studied for Network Resource Interconnection Service (NRIS), including 81% of all active US interconnection requests through the end of 2022 (Rand et al. 2023).[1] FERC characterizes NRIS as follows:

> *"Specifically, a transmission provider studying a generating facility for NRIS would study the transmission system at peak load, under a variety of severely stressed conditions to determine whether, with the generating facility operating at full output, the aggregate of generation in the local area can be delivered to the aggregate of load, consistent with reliability criteria and procedures"* (2022b, p. 34).

Put another way, NRIS requires a proposed generator ("interconnection customer") to be deliverable to load during severe grid conditions, such that the generator can be designated as a capacity resource and contribute to resource adequacy requirements.[2] To achieve full deliverability under such conditions, NRIS studies often identify the need for significant grid upgrades to relieve constraints, known as *network upgrades*. In this way, network upgrades in these jurisdictions are substantially driven in reaction to GI requests, as opposed to proactive transmission planning—an approach dubbed *invest and connect*. NRIS status is advantageous for interconnection customers because it makes generators eligible for capacity compensation and provides preferential curtailment treatment during emergency conditions (i.e., non-NRIS resources are curtailed before NRIS generating resources), allowing more revenue generation opportunity and certainty. The downside, however, is that the grid upgrades required for NRIS status can often make generators financially unviable, introduce uncertainty for project economics, and delay interconnection by years. For these reasons, some generators opt for a different interconnection service, known as Energy Resource Interconnection Service (ERIS).[3] ERIS does not require full deliverability during severe grid conditions, which means it is less

[1] An additional 8% of active interconnection requests were for joint NRIS and Energy Resource Interconnection Service (ERIS).

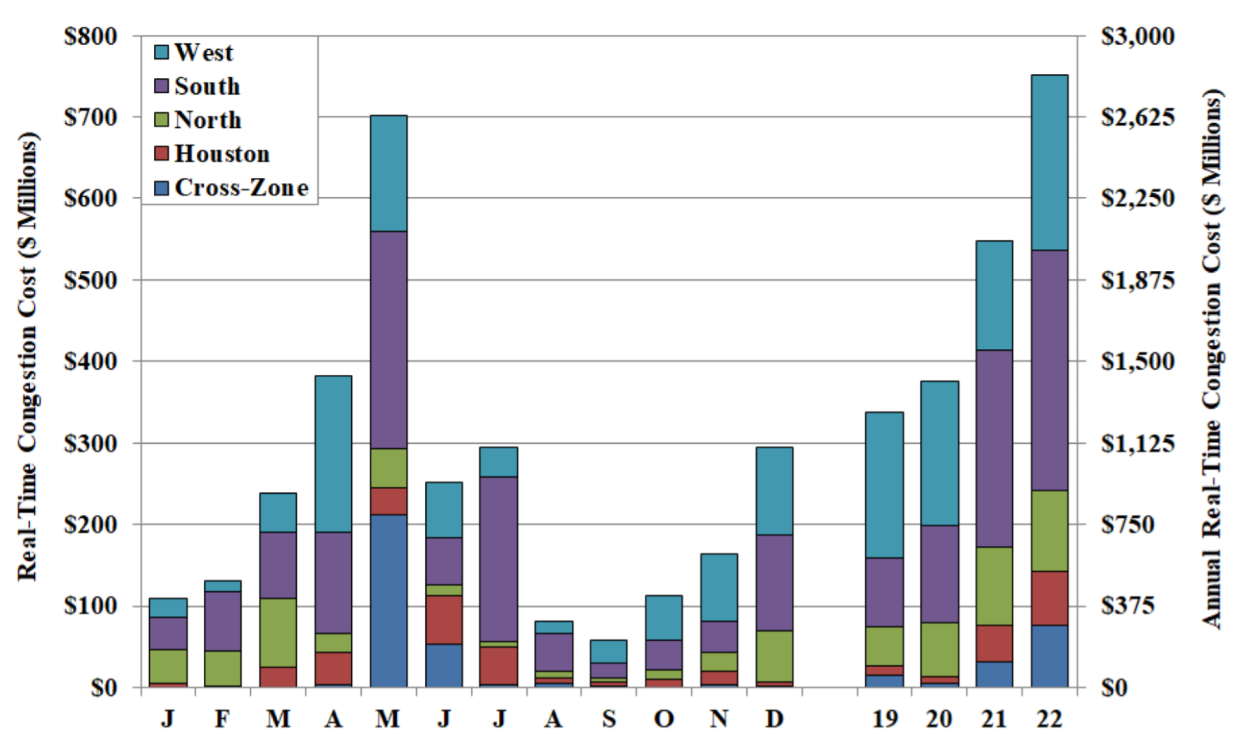
[2] *Severely stressed conditions* refers to contingency planning in accordance with North American Electric Reliability Corporation (NERC) Reliability Standard TPL-001, including the unplanned loss of a transmission line, generator or transformer. As discussed in the "Deficiencies of Invest and Connect" section, TPL-001 affords significant latitude to transmission providers with respect to contingency assumptions.

[3] Note that some transmission providers treat ERIS and NRIS almost identically, and some disallow ERIS altogether, particularly in the context of cluster studies. See further discussion below in the "Deficiencies of Invest and Connect" section.

likely than NRIS to require network upgrades. However, it provides only "as available," non-firm interconnection status to generators, meaning they are ineligible for capacity compensation and get curtailed before NRIS resources during emergency conditions, which in turn introduces greater uncertainty for project revenue forecasts.

ERCOT turns this construct on its head because it is currently an energy-only electricity market without capacity compensation. ERCOT manages network constraints via curtailments with market-based dispatch. In 2022, for example, ERCOT curtailed approximately 9% of available utility-scale solar generation and 5% of wind generation (Warady et al. 2023). These network constraints show up as higher electricity prices in different zones to reflect limitations on ERCOT's ability to deliver the lowest cost power to load, known as *congestion* (ERCOT 2020). ERCOT tracks and publishes day-ahead and real-time congestion costs (Potomac Economics 2023), allowing it to identify the most congested zones and costly constraints (Figure 2). In essence, all generators in ERCOT are treated like ERIS and there is no NRIS option. The overall trade-off for generators is the ability to interconnect much more quickly with fewer network upgrades[4, 5] in exchange for bearing more curtailment risk and not receiving capacity compensation.

Figure 2. ERCOT real-time congestion costs by zone—2022



Source: Potomac Economics 2023.

[4] Large generators can reportedly be developed and interconnected within as little as two to three years (Pfeifenberger 2022).
[5] In 2022, ERCOT reportedly completed full interconnection studies for 15 GW of solar and 8 GW of storage resources (Driscoll 2023).

Unlike an invest and connect approach, which relies substantially on interconnection customers to pay for network upgrades, ERCOT uses market price signals to identify higher-value grid upgrades via proactive transmission planning. ERCOT's transmission planning has been criticized as defective primarily because of inadequate cost-benefit assessment of economic-related upgrades, with a recent report card giving it a D+ (ACEG 2023). Nevertheless, ERCOT demonstrates an approach for enabling faster interconnection of new resources by managing resulting grid bottlenecks with economic curtailment and using congestion pricing to identify the next round of network upgrades. This general approach has become known as *connect and manage*, a term borrowed from a similar set of reforms implemented in the United Kingdom in 2010, which reportedly reduced lead times by five years (Pfeifenberger 2022, p. 7).

DEFICIENCIES OF INVEST AND CONNECT

The deficiencies of invest and connect to manage today's GI environment have been increasingly recognized in academic and grey literature (Mays 2023; Wayner et al. 2023; Kelly et al. 2022; Enel North America 2022; Pfeifenberger 2022; R Street Institute 2022). In a recent paper published in *IEEE Transactions on Energy Markets, Policy, and Regulation*, Jacob Mays makes the case that invest and connect is internally inconsistent and violates basic principles of efficient markets, and recommends moving to a connect and manage approach. Fundamentally, he argues, the problem arises because the addition of any new generator can be resolved without network upgrades:

> *"… even without any network upgrades, a feasible physical solution can always be found after introducing a new generator: trivially, operators could simply leave the generator offline and use existing resources. Accordingly, any interconnection study that identifies a reliability issue is by definition assuming a set of injections and withdrawals that could be avoided in real-time operations. From this perspective, it would seem that reliability concerns need not enter the interconnection study process at all: as long as the relevant constraints for transmission feasibility are included in commitment and dispatch processes, generators could simply be curtailed in real time to prevent violations"* (Mays 2023).

The implication of not accounting for the ability to redispatch and curtail generators to avoid violations is to create barriers to market entry that protect incumbent generators:

> *"… the effect of insisting on the feasibility of an assumed set of power injections is to protect the market position of incumbent generators that would otherwise be displaced by the new entrant. Rather than the competitive solution of simply allowing a newer, more efficient generator to use the transmission capacity previously utilized by an older generator, potentially with a payoff corresponding to any transmission rights held by the incumbent, the interconnection process insists on network upgrades enabling both to be dispatched"* (Mays 2023).

This protection of incumbent generators reveals inherent tension in electricity markets without full-strength energy prices (i.e., energy prices that reflect both energy and capacity value, if not ancillary services), where the ability to secure full deliverability rights can be an important feature to make new generators financeable. In other words, to attract investment in new capacity, non–energy-only markets rely on some degree of protection for the deliverability rights of incumbent generators.

Without sufficiently considering redispatch and curtailment opportunities, the invest and connect approach tends to favor outcomes that overbuild the transmission system. Compounding this issue, transmission providers often make unreasonably restrictive assumptions in GI studies that result in potentially avoidable violations, even apart from evaluation of grid enhancing technologies. As Pine Gate Renewables noted in its comments in FERC's interconnection rulemaking docket, "transmission providers will frequently use worst-case operating scenarios that require generators to address multiple contingencies or other overly conservative operating assumptions" (2022). Cypress Creek Renewables echoed this concern and identified NERC Reliability Standard TPL-001-4 P3 and P6 contingency types as particular areas of concern.[6] FERC declined to address these concerns in Order 2023.[7]

A related issue is when transmission providers study renewable generators for NRIS even when those generators don't contribute to resource adequacy requirements. For example, North Carolina and South Carolina's state jurisdictional interconnection procedures for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) require all generators to be studied as NRIS in cluster studies.[8] In both balancing authorities, new solar-only generators are currently assigned minimal capacity value (i.e., effective load carrying capability) unless paired with storage (Wintermantel and Benson 2022), meaning they are not counted toward resource adequacy requirements. Nevertheless, DEC and DEP still study solar generators under NRIS assumptions for deliverability. Specifically, DEC and DEP study solar during summer load conditions (Wallace 2019, p. 6), despite the fact that resource adequacy risk (i.e., loss of load expectation) in both balancing authorities is heavily concentrated in winter morning hours with minimal solar output (Wintermantel and Benson 2022, p. 10–11). In effect, generators without deliverability value are being studied for deliverability, making those generators more likely to trigger network upgrades than if they were studied under more appropriate assumptions.

There is also significant inconsistency in study assumptions across different transmission providers, which FERC largely declined to address in Order 2023 (FERC 2023, p. 273). As the American Clean Power Association and Renew Northeast noted in their joint initial comments,

[6] "… the application NERC Reliability Standard TPL-001-4 affords transmission providers the ability to exercise engineering judgment, particularly for the P3 and P6 contingency types, that can influence the outcome of interconnection studies and required upgrades, which, in turn can result in unreasonable network upgrade identification and subsequent cost assignment to new interconnection customers, even though the primary contributors to such upgrades are pre-existing reliability issues, or, in some cases, highly improbable contingencies" (Cypress Creek Renewables 2022, p. 4–5).

[7] "We decline requests for the Commission to set modeling standards, to require transmission providers to include their modeling standards in their tariffs, or to provide direction on how ERIS and NRIS should be studied and what service the interconnection customer should receive, and to require neighboring transmission providers to coordinate assumptions and update those assumptions quarterly. We find these requests to be outside the scope of the final rule" (FERC 2023, p. 838).

[8] Note that other utilities similarly disallow ERIS in cluster studies, such as Arizona Public Service and NV Energy. See for example: "Interconnection Requests shall be grouped in their respective Queue Cluster Window and by geographical areas, and shall be studied together for NRIS without regard to the nature of the requested Interconnection Service, whether ERIS or NRIS" (Arizona Public Service 2023, p. 417).

“transmission providers use different assumptions that significantly alter results—for example, what seasons are studied, the future years to study, generator output levels assumed in varying load and weather conditions, the acceptable mitigation solutions, and contingencies to be studied and mitigated” (2022, p. 28).

In the past, when most capacity additions were large central station generators, the cost of deep network upgrades were more readily borne by those generators or were socialized in the rate base as reliability-related upgrades. However, renewable generators have key attributes that make them less compatible with invest and connect. First, the average nameplate capacity of renewable generators is smaller than nonrenewable generators, making it more difficult to bear the cost of major upgrades due to economies of scale. This is partly related to the nature of deep network upgrades, which, when triggered, usually entail large step-changes in transmission infrastructure that are not amenable to modulation (e.g., miles of thermal reconductoring). While it is theoretically possible for multiple interdependent renewable generators to share the cost of major upgrades, in practice the coordination challenges are very difficult, hence the concern around cascading restudies in the context of large cluster studies.

Second, like gas peaker plants, the lower capacity factor of renewable generators means that any GI standard requiring such generators to reserve deliverable transmission capacity equivalent to their nameplate rating will result in much of the reserved interconnection capacity going unused (Pattanariyankool and Lave 2010). This is possible to address if transmission providers account for the full dispatch profile of the generator for purposes of GI study, but this is not frequently the case.[9] While it is possible for generators to request less interconnection capacity than their nameplate rating, there is generally no ability to modulate a GI customer’s reserved interconnection capacity; it is all or nothing.[10]

Third, the effective load carrying capability (ELCC) of renewable generators tends to be significantly less than nameplate capacity, unless paired with storage of equivalent nameplate capacity. In the context of invest and connect, this can be problematic because NRIS studies typically look at peak load conditions and assume generator output at 100% or near-100% of nameplate rating. For any generator with an ELCC below 100%, including the case discussed previously with DEC and DEP, such a study approach represents an inherent overbuild of the transmission system.

All of this is exacerbated by the predominant cost allocation principle of invest and connect, which generally assigns 100% of network upgrade costs to dependent generators via the GI process, despite the substantial benefits that accrue to load and subsequent interdependent generators.[11] In comparison to a proactive, multivalue, long-term regional transmission planning process where upgrade costs are allocated in proportion to received benefits, “the incremental

[9] Several commenters in Docket No. RM22-14-000 recommended that FERC provide additional guidance to transmission providers on assumptions around renewable dispatch profiles, which FERC declined.
[10] For instance, one could imagine an alternative arrangement where limited interconnection capacity is auctioned on an annual basis such that generators would bid to reserve a volume in accordance with their economically optimized output profile as market prices continually evolve.
[11] Note that some transmission providers, particularly those in the Western Electricity Coordinating Council, take a different approach to cost allocation by rate-basing identified network upgrades.

transmission upgrade approach in current GI processes can increase upgrade costs by multiples, increasing uncertainty and total costs by tens of billions of dollars per region, while causing underinvestment in upgrades because those paying for the upgrades do not receive many of the benefits" (R Street Institute 2022). FERC is considering transmission cost allocation concerns in a separate rulemaking (Docket No. RM21-17-000 [FERC 2022a]), but the issue is unlikely to be resolved in the near future.

IMPROVING ERIS SERVICE

Non–energy-only markets are here to stay for the foreseeable future, raising the question of how best to work within the prevailing ERIS–NRIS interconnection structure outside ERCOT. In her concurrence, Commissioner Clements encouraged further consideration of how to streamline ERIS, noting that the commission could address this topic in a subsequent rulemaking (Clements 2023, p. 13).

An initial step is to characterize how transmission providers currently treat ERIS and how they intend to treat it under cluster studies in compliance with Order 2023. According to multiple commenters, there is significant inconsistency in the treatment of ERIS (American Clean Power Association, Renew Northeast 2022; Enel North America 2022; Cypress Creek Renewables 2022).[12] Since FERC declined to provide guidance on how cluster studies should address ERIS (FERC 2023, p. 273, 317), apart from potential affected system studies, it is unclear what if anything transmission providers will propose in their compliance filings.

Beyond the goal of greater consistency, the overarching issues to address with ERIS as highlighted by commenters fall into three general categories: interaction, modeling, and impact threshold, outlined in Table 1 and summarized as follows.

Interaction

In theory, the most basic of these issues is process. Enel North America and Cypress Creek Renewables both proposed a two-step process, with ERIS preceding NRIS. A key advantage of this approach is to limit the interdependence of ERIS and NRIS projects and mitigate the risk of cascading withdrawals and restudies. However, it is unclear if FERC's order will practically allow such flexibility, given the specific components and timeline it establishes for cluster studies, which appear designed to accommodate an integrated cluster. Nevertheless, some transmission providers may be motivated to propose such an approach. For example, PacifiCorp's comments expressed preference for a two-step process (2022, p. 24).

[12] See for example: "From Enel's experience developing new generators across the country, we have observed vastly different treatments of ERIS and NRIS that have significant implications for the final interconnection costs assigned to an Interconnection Customer… Some Transmission Providers require ERIS studies to be completed as a baseline service and treat NRIS studies as an incremental service. Other Transmission Providers study NRIS first and then add ERIS-only generators in an incremental study. Other Transmission Providers view ERIS and NRIS services as mutually exclusive products and only study one or the other" (Enel North America 2022).

Table 1. ERIS reform options

Category	Issue	Option A—Default	Option B—Potential Alternative	Other Considerations
Interaction	How should ERIS and NRIS studies interact?	One-step: integrated ERIS-NRIS cluster	Two-step: ERIS cluster, NRIS cluster	• Interdependency of ERIS and NRIS studies • Optionality and conversion to NRIS
Modeling	How to model ERIS studies?	Power flow (PF)	Security-constrained economic dispatch (SCED)*	• Hybrid PF-SCED model • Fuel-specific dispatch assumptions
Impact threshold	When to assign upgrades to ERIS customers?	Transmission providers set impact threshold	Establish consistent impact threshold of ~20%	• Other potential thresholds (e.g., cost, electrical distance)

* SCED considers network constraints and hence power flow. See further discussion and footnotes that follow.

Modeling

Multiple commenters discussed concerns related to existing ERIS study models. One of the most common concerns is that ERIS study models do not sufficiently consider redispatch opportunities and frequently make other overly restrictive assumptions. Enel North America and Advanced Energy Economy went as far as urging FERC to direct transmission providers to replace power flow models for ERIS studies with security-constrained economic dispatch (SCED) models,[13, 14] which would allow for cost-benefit evaluation of identified network upgrades.[15] As an alternative, Enel North America emphasized the importance of accounting for more accurate fuel-specific dispatch assumptions.

Impact Threshold

Impact threshold refers to the issue of when identified network upgrades should be assigned to ERIS projects. More specifically, it refers to the minimum impact threshold below which an ERIS

[13] Enel North America stated that existing power flow studies "only look at a few discrete snapshots of system conditions and are unable to capture the breadth of a full yearly dispatch of a generating unit," whereas SCED studies "evaluate power flow conditions across all hours of the year using a representative model of load, weather conditions, and energy market rules" and thus determine "how often constraints exist and the severity of those constraints" (2022).

[14] Advanced Energy Economy stated, "use of SCED studies would provide valuable information regarding the frequency of use of proposed transmission upgrades, and would identify whether infrequent curtailment of the resource (consistent with its request for ERIS service) would address the identified constraint, eliminating or reducing the interconnection customer's cost responsibility and reducing project withdrawals" (2022b).

[15] Enel North America proposes that "upgrades should be assigned for ERIS based on added value to the generator in the form of maximizing the 'as available' interconnection service as measured by reduction of revenue loss due to congestion and curtailment" (2022, p. 75).

project is exempted from cost responsibility for any given network upgrade identified in the power flow model. In technical terms, this impact is measured by the *transfer distribution factor* (TDF).[16] Several commenters requested that FERC establish a consistent minimum threshold across transmission providers, with some recommending a specific threshold of 20% (American Clean Power Association, Renew Northeast 2022; Pine Gate Renewables 2022; Enel North America 2022; Advanced Energy Economy 2022a). The higher the minimum threshold, the more ERIS projects would be allowed to interconnect at faster speed and lower cost.

MANAGING CURTAILMENT RISK

As discussed previously, the fundamental trade-off presented by ERIS is faster, cheaper interconnection in exchange for higher curtailment risk and no capacity compensation. ERCOT's interconnection performance is compelling evidence that this trade-off is workable in the context of energy-only markets with full-strength energy prices. What's less clear is how well it will work in non–energy-only markets. This quandary is a central theme of Mays' paper:

> "*… without an accompanying process for network expansion, new generators would be subject to substantial congestion risk, including uncertainty regarding eligibility to participate in capacity payments. A more substantial reform could reassign this risk by default to system planners or transmission owners, who have greater ability than generation owners to address this risk directly through network expansion*" (2023, p. 5).

In non-ERCOT ISOs/RTOs with transparent information on pricing, congestion, and dispatch models, it is conceivable that certain GI customers could manage such curtailment risk with the development of more sophisticated hedging instruments. To this end, Mays proposes a complex financial instrument that he labels a *Financial Interconnection Right*, which would allow interconnection customers to pay a fixed fee to transmission system operators in exchange for more revenue certainty to control for uncertain levels of congestion-related curtailment.

The challenge is even more acute in non–ISOs/RTOs, where a dearth of market information makes it impractical to finance new generators with ERIS interconnection without long-term power purchase agreements (PPAs). This challenge is partly illustrated by the fact that few if any qualifying facilities (QFs) have ever been financed in non–ISOs/RTOs under as-available energy rates, or even under available fixed-price QF PPAs under ten years in tenor, despite federal law requiring preferential curtailment treatment of QFs as must-take resources.[17]

In recent years, an attempted solution in non-RTO jurisdictions has been to establish curtailment limits within PPAs. One of the more notable examples of this is the form PPA for Duke Energy's annual solar procurement program, a busbar PPA that caps the potential rate of uncompensated curtailment at 10% of expected annual production for projects in DEP and 5% in DEC.[18] The PPA

[16] Note that TDF is also commonly referred to as *DFAX* or *distribution factor.*

[17] The Public Utility Regulatory Policies Act (PURPA) requires electric utilities to purchase all power made available by QFs, which are required to be curtailed after utility-owned generators and only during system emergencies—commonly referred to as the *must-take requirement*.

[18] See DEC/DEP 2022 solar procurement *pro forma* PPA: https://www.duke2022solarrfpcarolinas.com/RFP-Documents.

allows Duke Energy to “dispatch down” the facility for effectively any reason, provided Duke Energy compensates the facility for any curtailed production in excess of the cap, based on the PPA’s fixed, bundled dollar per megawatt-hour price.

Market participants have filed comments with the state utilities commission noting drawbacks with this approach (Carolinas Clean Energy Business Association, Clean Power Suppliers Association 2022, p. 10). Since future curtailment rates are very difficult to forecast in non-RTOs, most projects bidding into the procurement can be reasonably expected to assume by default that all or most of the uncompensated curtailment cap is ultimately used by Duke Energy. In turn, bidders will increase their PPA bid prices accordingly, meaning that ratepayers are likely to end up paying for such curtailment whether or not it is directly compensated.[19] However, by encouraging higher bid prices, the use of PPA-based curtailment caps ends up “paying” for curtailment whether or not it actually occurs.

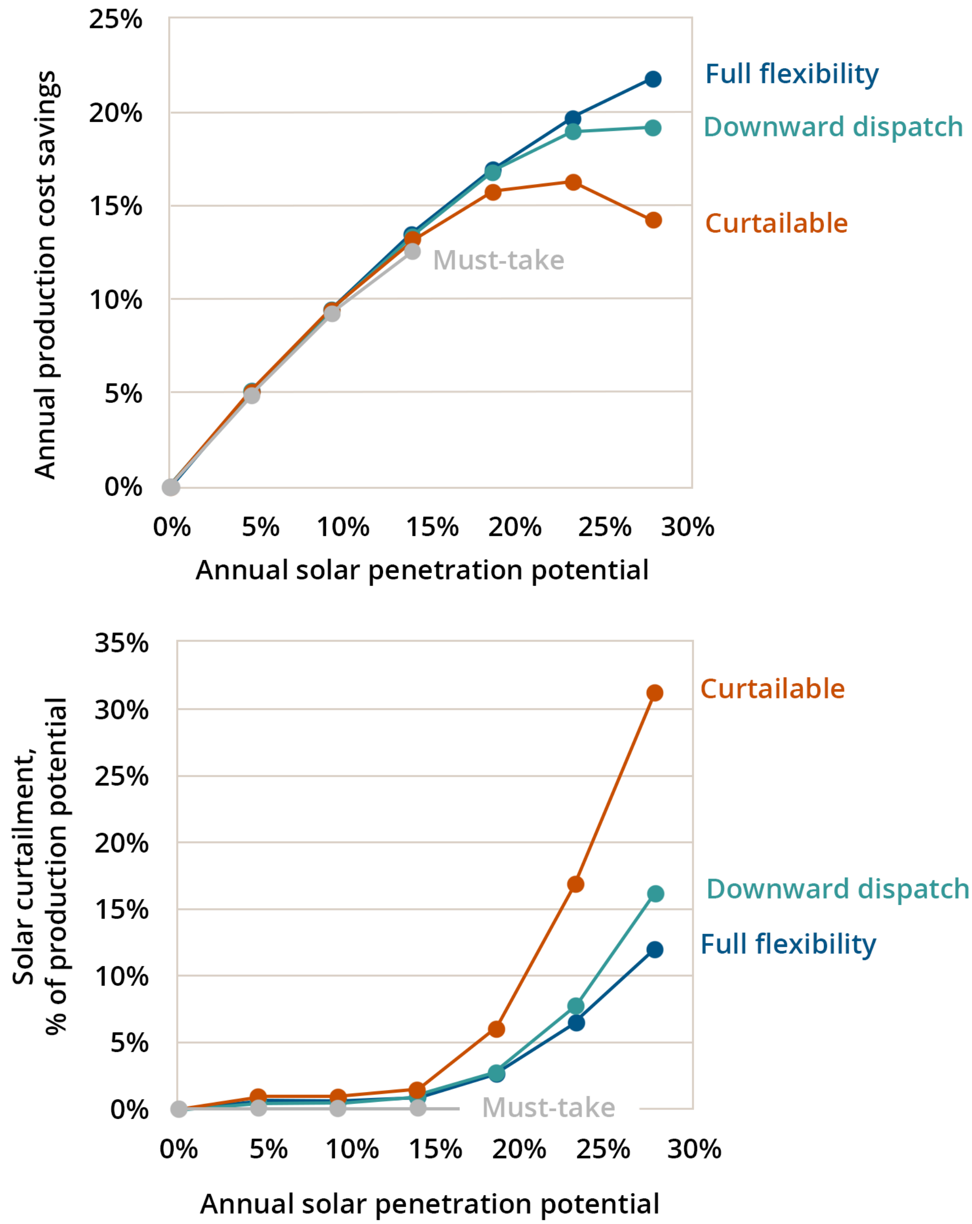
Multiple studies have found that more flexible solar power plant operation can lower system costs and even reduce curtailment rates by contributing to balancing and regulation requirements (Wang et al. 2022; Frew et al. 2021; First Solar 2020; E3 2018). By allowing for real-time plant control via dispatch down and up signals, solar generators can contribute to “footroom” and “headroom” requirements and thus support ramping and load following in a way that reduces the need for more expensive fossil-based resources. One study by Energy and Environmental Economics (E3), for instance, simulated a Florida utility’s system and found that at solar penetration levels above 20%, solar curtailment could be reduced by more than half by enabling full flexibility (dispatch down and up) instead of only curtailing to avoid oversupply (Figure 3).

To capture these benefits, an alternative, simplified approach to the traditional dollar per megawatt-hour PPA structure would be to remove the curtailment limit from the PPA altogether and compensate generators on a fixed dollar per megawatt-month basis over the term of the PPA (i.e., capacity-based compensation). This is effectively how all generators owned by regulated utilities are compensated, albeit with a guaranteed rate of return. It is also how battery storage is compensated in many solar-plus-storage PPAs, often referred to as a *tolling agreement* (Lowder 2021). Under this arrangement, the utility would control the independent generator for real-time operations via both dispatch down and dispatch up signals.

The downside to this approach is that it does not value or otherwise incentivize yield optimization, and it does not incentivize availability during peak load periods. One way to address this is with contractual performance guarantees, subject to penalties for nonperformance. Another approach, which is not mutually exclusive with performance guarantees, is to compensate generators for producing during peak load hours, analogous to demand charges for large electricity customers. Generators would thus submit two bid prices, a fixed dollar per megawatt-month price applicable to all months over the PPA term, and a dollar per megawatt-hour price for designated peak hours over the PPA term.

[19] Put another way, ratepayers will pay for curtailed production in one of two ways. If PPAs allow for uncompensated curtailment, ratepayers will implicitly pay for curtailed production via higher average PPA prices. If PPAs do not allow for uncompensated curtailment, ratepayers will explicitly pay for curtailed production via direct compensation for expected production.

Figure 3. Flexible solar benefits—E3 simulation results



Source: Adapted from E3 2018, p. 34.
Note: Savings normalized to system production cost without solar generation.

A variation on this approach has been proposed by First Solar to address the same concern. As First Solar notes, "two solar plants may both have a total capacity of 100MW, but one may be worth more because it is located in an area with higher solar insolation. Or, one may have a higher capacity factor on average due to superior panel technology or using tracker technology" (2020, p. 26). They propose a PPA structure in which compensation is based on the generator's total expected energy output (dollar per megawatt-hour) prior to output adjustments for flexibility services. This is effectively equivalent to Duke Energy's preexisting solar PPA as described previously, albeit with the uncompensated curtailment cap set to zero. These various options are summarized in Table 2.

MANAGING HYBRID RESOURCES

In 2022, the volume of hybrid generation capacity in US interconnection queues grew by 59% over 2021 volumes (Bolinger et al. 2023). The trend toward pairing renewable generators with storage introduces additional considerations around the use of ERIS interconnection in non–energy-only electricity markets, given that one of the largest values associated with paired storage is on-peak capacity. As discussed previously, ERIS resources are generally ineligible for capacity compensation, which might at first glance suggest that ERIS is incompatible with hybrid resources. However, there are several potential solutions.

One solution is to preserve the option for ERIS interconnection customers to pursue NRIS. This could be accomplished via a two-step ERIS-NRIS study process, or potentially even in the context of an integrated ERIS-NRIS cluster study by providing GI customers an ERIS and NRIS result and allowing them to choose either path after the first cluster study.[20] In addition, a GI customer that executes an ERIS interconnection agreement (IA) could be allowed to re-apply to upgrade the same IA to NRIS in the next annual cluster study or thereafter.[21]

Alternatively, the GI customer could submit a separate NRIS application in the same cluster, albeit limited to the nameplate rating of the paired storage. Assuming the storage nameplate rating is less than the renewable generator, this approach would reduce the requested volume of NRIS capacity and mitigate potential network upgrades. As another alternative, if the

Table 2. Curtailable PPA options

PPA Type	Compensation	Curtailability	Curtailment Compensation
Must-take	Fixed dollar per megawatt-hour for actual energy output	System emergencies only	None
Controlled energy	Fixed dollar per megawatt-hour for actual or expected energy output	100% curtailable	Compensated beyond defined cap (0% to 100%)
Controlled capacity	Fixed dollar per megawatt-month	100% curtailable	N/A
Controlled capacity with peak incentive	Fixed dollar per megawatt-month plus on-peak dollar per megawatt-hour	100% curtailable	Optional for peak curtailment

[20] American Clean Power Association and Renew Northeast recommended that "resources where the electric storage resource and generator are co-located, but have two resource IDs, should be allowed to choose to study each component separately. Doing so would allow, for example, a wind or solar facility to obtain a faster study (for example, seeking ERIS) while the co-located storage could get a more detailed study for NRIS" (2022, p. 61).

[21] Note that this allowance currently exists in some US jurisdictions.

transmission provider allows, it may be possible to submit a single hybrid ERIS-NRIS request, with the NRIS portion limited to the nameplate rating and charge/discharge profile of the paired storage.

More broadly, in some cases the tension between ERIS and hybrid resources may tip the scales in favor of pursuing standalone storage over paired storage, especially to the extent that standalone storage can be positioned in grid locations that are less likely to trigger network upgrades, or even mitigate congestion via storage as a transmission asset (Brown et al. 2023). A growing number of renewable developers have established a preference for hybrid projects over solar-only or wind-only (*renewable-only*), but if ERIS can facilitate faster and cheaper interconnection, it may be advantageous to pursue ERIS by default while preserving the option for a storage addition via NRIS if interconnection capacity is available, which could in turn allow those renewable generators to mitigate higher curtailment rates under ERIS.

Regardless, in jurisdictions that assign little if any ELCC value to renewable-only generators, there is even less justification for pursuing NRIS study if the generators do not include paired storage. However, as discussed previously, several transmission providers currently do not allow interconnection customers to be studied for ERIS in cluster studies. In effect, these projects are reserving limited firm interconnection capacity that may go largely unused, depending on the transmission provider's GI study assumptions.

LINKING INTERCONNECTION, TRANSMISSION PLANNING, AND PROCUREMENT

To make connect and manage an improvement over status quo, proactive, holistic transmission planning is equally important as improved ERIS-based standards. The basic bargain is to avoid reliance on the GI process to support deep network upgrades and instead pursue deep upgrades through a separate planning process.

FERC is attempting to improve regional transmission planning and cost allocation in a separate rulemaking (RM21-17-000), for which an order is pending (FERC 2022a). Regardless of its outcome, there is growing interest in rationalizing the relationship between GI and transmission planning processes, and in the case of non–ISOs/RTOs,[22] with competitive procurement. As Commissioner Clements stated in her concurrence, "there may also be opportunities to streamline the interconnection process by more closely linking it to the transmission system planning process… In some regions of the country, it may be appropriate to link aspects of the interconnection process to resource solicitation" (2023, p. 6–9).

One important benefit of the annual cluster studies now mandated by FERC Order 2023 is how they will produce ongoing analysis on network upgrades necessary to integrate all queued projects, as opposed to producing studies specific to only single generators under the prior serial study process. These cluster study results will become even more useful thanks to the various measures intended to discourage speculative projects and improve study methodology.

[22] Or state-directed competitive procurements within ISOs/RTOs.

Holistic transmission planning also depends on the availability of generator price information; for ISOs/RTOs, this information comes from market congestion price signals. In this context, accelerated interconnection via ERIS can be viewed as a form of price discovery in ISOs/RTOs by enabling generators to participate more quickly in real-time and day-ahead markets and thus reveal their prices to the transmission planning process.

In non–ISOs/RTOs, the task is more complex. Such markets have no market congestion pricing, and they generally offer no viable offtake path for independent generators besides competitive procurement.[23] In other words, there is no mechanism for direct price discovery besides competitive procurement in the form of long-term PPA bid prices. Moreover, as discussed previously, market participants in non–ISOs/RTOs have little information available to forecast future curtailment rates, which means their PPA bid prices cannot accurately account for curtailment.

To date, this dynamic has been addressed by overlaying competitive procurements with the GI study process, with generators designated as NRIS and with the cost of any identified network upgrades assigned to the bids for purposes of bid scoring. However, this increases reliance on the GI process to identify and fund deep upgrades. As documented in the FERC interconnection rulemaking, such an approach is usually more expensive than proactive transmission planning and increases the risk of cascading dropouts. An additional downside to the NRIS-only approach is that generators contingent on deep network upgrades are by default prevented from interconnecting until those upgrades are completed, potentially foregoing production cost savings and other system benefits in the meantime unless the generators are allowed to provisionally interconnect.

As an example of current incompatibilities, in mid-2022 Duke Energy proposed a set of proactive "Red Zone" upgrades to facilitate more solar interconnection, which were ultimately accepted later in the year by the North Carolina Utilities Commission (NCUC). However, the NCUC rejected the proposal's recommendation to incorporate these upgrades into the baseline for Duke Energy's first general cluster study and its associated annual solar procurement. As such, despite the upgrades getting approved for the express purpose of enabling lower-cost solar projects, such projects were penalized for those upgrade costs in the procurement evaluation process (Clean Power Suppliers Association, Carolinas Clean Energy Business Association 2022, p. 8–10).

A potential solution would be to require bids into such procurements to be designated as ERIS (except for paired storage as appropriate, as discussed previously) and defer decision-making on deep network upgrades to the proactive planning process. An objection to this approach is that bid prices would not reflect potential congestion-related curtailment, raising the question of whether curtailment rates could be reasonably approximated for bid scoring. Such approximations would carry inherent uncertainty, though it is unclear whether this uncertainty would materially exceed the uncertainty inherent in any power flow cluster study premised on

[23] The primary exception here is the PURPA QF offtake option, but very few US jurisdictions now offer QF rates and contractual terms that enable QFs to be financed, leading to the minimal number of new QF contracts in recent years. The other exception is limited green tariff program options where they exist.

forecasts of load, generation, and grid-enhancing technologies.[24] A hybrid approach may be worth considering, in which ERIS bids would also be studied as NRIS and assigned a "shadow" network upgrade price based on the NRIS results for purposes of bid scoring, while retaining ERIS status. The benefit of this approach would be to account for the expected impact of congestion-related curtailment on project economics, but without the delay and complications associated with large network upgrades, which would be left to the transmission planning process.

In short, the fundamental trade-off entailed in ERIS-based competitive procurements in non–ISOs/RTOs would be accepting the risk that some projects could be awarded over others based on potentially inaccurate curtailment or network upgrade estimates, in exchange for the benefits of ERIS-based interconnection and proactive transmission planning.

CONCLUSION

FERC has taken meaningful steps with Order 2023, and as Commissioner Clements outlined in her concurrence, more work is necessary to address current challenges. In particular, the questions surrounding deeper reform options call for thoughtful consideration among stakeholders and analysts in the years ahead. This paper contributed to this process by reviewing foundational challenges with existing procedures that are not resolved by Order 2023 and outlining conceptual issues and potential solutions related to implementation of connect and manage in non–energy-only electricity markets, particularly as related to management of curtailment risk, hybrid resources, and the linkage of interconnection, transmission planning, and competitive procurement.

[24] According to R Street Institute, "currently, GI for NRIS and capacity accreditation processes presume centralized administrative modeling is capable of accurately determining, years in advance, what generation can meet particular load needs. This false premise introduces extensive administrative uncertainty that translates into system performance risk" (2022).

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