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Generator Interconnection, Network Expansion, and Energy Transition

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***Abstract*—Inefficient coordination between decentralized generation investment and centralized transmission planning is a significant barrier to achieving rapid decarbonization in liberalized electricity markets. While the optimal configuration of the transmission grid depends on the relative social costs of competing technologies, existing processes have not led to transmission expansion consistent with declines in the cost of wind and solar combined with increased estimates of the social costs of traditional thermal resources. This paper describes the negative feedback loop preventing efficient interconnection of new resources in U.S. markets, its connection to conceptual flaws in current resource adequacy constructs, and the ways in which it protects incumbent generators. To help resolve these issues, the paper recommends a shift to a "connect and manage" approach and outlines a straw proposal for a new financial right connected with transmission service. From a generator perspective, the effect of the proposed reforms is to trade highly uncertain network upgrade and congestion costs for a fixed interconnection fee. From a transmission planning perspective, the goal is to improve the quality of information about new generation included in forward-looking planning processes. Simulation on a stylized two-node system demonstrates the potential of the approach to facilitate a transition to clean technologies.**

***Index Terms*—Electricity markets, energy transition, generator interconnection, transmission planning**

I. Introduction

LARGE-SCALE modeling of the U.S. energy system typically finds that low-cost approaches to decarbonization include a significant role for wind and solar resources supported by substantial expansion of transmission infrastructure [1]–[3]. In U.S. systems, however, existing processes for transmission planning have not led to expansion on the scale predicted to be beneficial by models that co-optimize transmission and generation. Several factors may help explain this disconnect, including conflicts between Federal and State regulatory authorities contributing to difficulties siting and permitting new lines [4], the efforts of incumbent generators to retain market power in their area [5], and a lack of coordination between neighboring system operators [6]. Among the potential contributing factors, this article focuses on the lack of coordination between generation and transmission investment within the territory of a single liberalized market.

While coordinating between centralized transmission planning and decentralized generation investment has always been a challenge in liberalized electricity markets [7]–[11], the problem has grown in recent years with increasing investor interest in wind and solar generation [12]. At the end of 2022, interconnection queues for systems covering approximately 85 percent of U.S. consumption held over 2,000 GW of capacity, a quantity well above the amount currently operational in those systems. Solar, wind, and storage represent approximately 95 percent of the total [13]. Correspondingly, projects hoping to connect to the system have reported delays in interconnection, bringing uncertainty and additional cost [14]. In a negative feedback loop, uncertainty and delays have led project developers to submit a larger number of more speculative interconnection requests in the hopes of identifying a favorable project size and location. This larger number of requests prompts additional interconnection studies, leading to further delays in the process. From an engineering perspective, the goal of the interconnection study process is to anticipate potential reliability problems in advance before a new generator is allowed to enter the market. From an economic perspective, however, long delays and cost uncertainty contravene the free entry assumption of competitive markets, i.e., that new producers are able to sell goods without undue barriers to entry.

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A. Context and Related Literature

This paper considers the economic and cost allocation implications of two competing approaches to the interconnection at the transmission level, the names of which derive from the grid access reforms implemented in 2010 in the U.K. [15]. In U.S. systems apart from the Electric Reliability Council of Texas (ERCOT), network upgrades can be divided into three categories: those driven by local reliability needs, those determined as part of a centralized planning process, and those prompted by generator interconnection requests [6]. The presence of upgrades in the third category reflects the "invest and connect" approach to interconnection. Since these upgrades are myopic and geared to particular generators (or small clusters of generators), subsuming this category into the second could lead to more efficient network expansion decisions overall. The example of ERCOT, which follows a "connect and manage" approach with substantially shorter queue times than other U.S. systems [16], shows that the third category is not strictly necessary from a reliability perspective. Simply eliminating the third category of upgrades, however, raises two issues. First, one goal of transmission cost allocation is to encourage entrants to connect at favorable locations in the network (e.g., near load centers). Typical practice in the U.S. is to allocate the cost of upgrades in the third category to interconnecting generators and the cost of those in the second category to loads in one or more zones that benefit from the project [14]. A change in processes would therefore alter the overall cost allocation, with potential implications for the efficiency of generator siting decisions [17]–[19]. Second, in order for the centralized process to lead to an efficient expansion, planners must have a plausible view of the generation investment decisions that will arise as a result of the chosen transmission configuration [20]–[24]. This requirement is in tension with a core rationale of competitive markets: central planners may not have an accurate view of the future costs and actions of potential entrants to the market. At present, centralized planning processes include only generators that have a signed generator interconnection agreement, implying that they have already moved through the interconnection process [6]. As a result, generation and transmission expansion decisions proceed in a largely myopic and sequential manner, potentially missing large opportunities that might be found with co-optimization [25]–[27]. A change in processes could alter the information about future generation additions available to planners, with potential implications for the quality of the resulting transmission plan.

Current processes violate principles of cost allocation in three ways. First, systems nominally follow the principle that beneficiaries of the transmission system should pay in rough proportion to the benefits they receive [28]. Since network upgrades prompted by generator interconnection potentially benefit all current and future users of the network, it is unlikely that allocating cost to interconnecting generators conforms to this principle [29]. Second, since generators cannot change their location once constructed, it is desirable that network transmission charges be determined ex ante [30], [31]. As previously mentioned, prospective generators have little way to determine costs upon entering interconnection queues. Further, in markets with nodal pricing, such as those in the U.S., a portion of the total cost of transmission is implicit in locational prices seen by market participants. In this context, uncertainty in congestion costs over a project's life amounts to a failure to allocate costs ex ante. While in theory financial transmission rights (FTRs) could be used to convert uncertain congestion costs into a stable transmission charge [32], [33], there is at present no evidence that FTRs have been used to support project finance [34]. More generally, FTR markets in the U.S. have encountered a number of problems since their inception, leading many to question whether they are accomplishing their stated aims [35]. Along these lines, while nodal markets provide superior incentives for generation siting in expectation [17], [36], their performance depends on the ability of market participants to effectively manage congestion risk [37], [38]. The issue of liquidity in these hedging markets features prominently in debates about moving from a zonal to a nodal design in Europe. Third, efficiency suggests that on the margin, costs should be assigned to those in a position to control them [39], [40]. In the transmission context, generators have limited ability to influence either the initial cost of network upgrades or the ongoing cost of congestion. Instead, these costs are governed by decisions made by transmission owners and system planners with no direct financial stake in the outcome. In situations where transmission owners also own generation assets, the financial incentives may in fact push in the opposite direction: given the discretion incumbent transmission owners have in planning processes, they may preferentially promote network upgrades that benefit affiliated generators.

While similar issues affect the interconnection of resources at the distribution level, the lack of economic dispatch and nodal prices in that context creates different challenges for cost allocation. Accordingly, this paper limits the discussion to the transmission level.

B. Goals of This Paper

In light of these considerations, the primary contribution of this paper is to consolidate the grey literature on cost allocation of transmission network upgrades for interconnection, a topic that has received little attention in the academic literature despite its high relevance to practice, and connect it to more developed strands of literature on transmission–generation coordination and regulation of transmission access. After describing the economic inefficiencies in current generator interconnection processes, the secondary contributions are 1) to present arguments in favor of the "connect and manage" approach rather than the "invest and connect" approach and 2) to propose a new financial instrument to address the cost allocation and risk consequences that arise in the "connect and manage" approach. The recommendations seek to eliminate the third category of network upgrades while bringing overall cost allocation roughly in line with established principles and improving the quality of information in centralized transmission plans. For an announced interconnection fee, potential new generators would be able to join the system without any requirement of network upgrades. However, both new and incumbent generators would be subject to the normal strictures of security constrained economic dispatch, meaning that new generators might see lower prices than would likely be observed after completion of network upgrades. To account for this risk, new generators would be granted a hedging instrument, labeled a financial interconnection right (FIR), in exchange for its fixed interconnection fee. Similar to the goal of [41], the result for generators would be a smoother price pattern over the course of a project's life, with a reduction in the basis risk associated with differences between nodal prices and those at trading hubs.

In the context of debates between policies of "generation leads transmission" and "transmission leads generation" for coordination of sequential investments, the proposal amounts to a strategy of "hedged generation leads transmission." In the context of debates between zonal and nodal pricing for transmission access, the proposal amounts to "nodal with a default hedge." The overall effect has analogs in the transmission access regimes of some current zonal markets. The U.K., for instance, uses a single energy price but zonal Transmission Network Use of System charges that update annually. Going further, the Modified Congestion Relief Market model in Australia preserves a default hedge to zonal prices but gives participants access to nodal prices with the goal of improving operational efficiency [42]. By the same token, while the proposal was developed in the context of U.S. nodal markets, a variant may also be useful in markets considering a transition from zonal to nodal pricing [43]. By defining and granting FIRs as part of the transition, regulators could limit distributional impacts of such a change.

Separate from streamlining the interconnection process, there are two reasons why hedging new generators as a matter of course could improve results in liberalized markets. First, with revenues less dependent on nodal prices, generators would likely have less incentive to exercise the local market power endemic to congested electricity markets [44]. Second, the presence of this hedge could enable reform or dissolution of poorly functioning markets for existing financial transmission rights, which as currently implemented introduce opportunities for price manipulation [45], [46] and have resulted in large transfers from consumers to financial traders [47], [48].

Alongside the potential benefits, the risk transfer facilitated in this proposal introduces other potential inefficiencies. While the structure of the FIRs would preserve the efficient incentives for short-run production decisions provided by nodal prices, long-run siting incentives would be determined by decisions made regarding the fixed interconnection fee at different locations. Given the ambiguous probabilities associated with future transmission expansion, it can be guaranteed that under this proposal, ex post analyses will reveal generators that have underpaid for their connections. Under the present regime, however, these same ambiguous probabilities lead to unhedgeable risk for all potential entrants. The present analysis does not attempt a full empirical study comparing the proposed method against the status quo. Instead, the goal is to introduce and motivate the concept of FIRs, as well as discuss key questions around their definition, pricing, and allocation.

II. Deliverability, Resource Adequacy, and Incumbent Protection

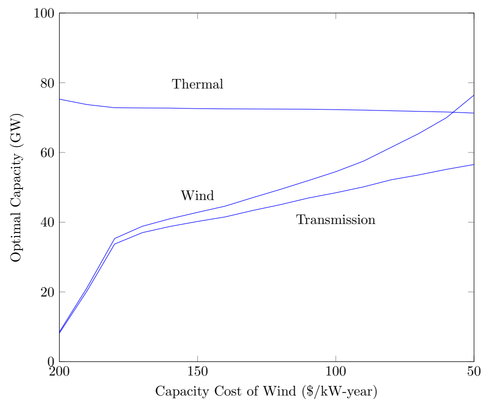
The proposed reconfiguration begins with the internal inconsistency in the "invest and connect" approach, which focuses on the physical rather than the economic aspects of incorporating new generators. This inconsistency arises in the way interconnection studies construct an assumed set of power injections and withdrawals and identify reliability violations from the resulting flows. The issue with this reliability focus is that, 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. In nodal markets, the need for this curtailment would then be expressed in the real-time price. Accordingly, the primary question of interconnection is inherently economic, necessitating a comparison between the cost of network upgrades against the incremental cost of operating the system without those upgrades.

An engineering objection to this logic is that economic dispatch models do not contain all of the relevant constraints for transmission feasibility. For example, real-time markets typically use a linear approximation of the power flow equations and omit complications related to dynamic and voltage performance. In this context, interconnection studies (as well as other offline analyses regularly performed ahead of real-time operations) can be seen as a way to ensure that solutions found in the models used in real time will be feasible to the full problem with at most minor adjustments despite their simplified representation of the network physics. To assist in this goal, offline analyses regularly lead to the addition of nomogram constraints, i.e., generic linear or piecewise linear limits on power transfers that serve as proxies for more detailed descriptions incompatible with the convex optimization models used for dispatch and pricing (see, e.g., [49]). With the proposed reconfiguration, studies currently performed prior to interconnection would instead need to be performed and updated on an ongoing basis, potentially as part of the regular long-term planning process. Since these studies would be able to focus on generators actually in operation instead of requiring assumptions about the future generation mix, their quality and relevance would likely be improved.

A more critical objection to a purely economic interpretation of interconnection stems from inadequacies in the resource adequacy mechanisms used in U.S. markets outside of ERCOT. Namely, while energy markets are nodal, resource adequacy requirements are conducted at a zonal level. In order to be considered a capacity resource, interconnecting generators therefore undergo additional tests assessing "deliverability." In other words, the interconnection study process is in part a way for the system operator to confirm that the zonal simplification used in the resource adequacy construct is reasonable in the case of the interconnecting resource. In an energy-only market with full-strength nodal prices, such a concept is unnecessary, enabling the more straightforward interconnection process employed in ERCOT. Other markets distinguish between lower-level energy resource interconnection service (ERIS) for non-capacity resources vs. higher-level network resource interconnection service (NRIS), which comes with associated Capacity Interconnection Rights (CIRs). In this way, a failure to produce full-strength prices in the energy market creates additional demands on the interconnection study process and slows the adoption of new resources.

Viewed in economic rather than engineering terms, 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. Further, the queue process itself opens an opportunity for the exercise of market power. By strategically adding new resources to the queue and later withdrawing them, owners of incumbent generation have a low-cost way to delay the entry of new competitors.

Fig. 1: Separation between optimal size of remote wind and transmission. As wind gets less expensive, it is advantageous to install capacity beyond the available transmission. Accordingly, requiring that the full installed capacity be deliverable would be inefficient.



The effects of the internal inconsistency in the current interconnection process are exacerbated by the inherently inefficient standard of full deliverability for variable resources. As the input costs of variable generators decrease, it becomes efficient to oversize generation equipment relative to equipment needed for conversion and transmission. For example, the average inverter loading ratio of solar plants has steadily grown as photovoltaic panels have become less expensive [50]. A similar effect holds for transmission. To illustrate this effect, consider a simple two-bus system served by wind at a remote bus and thermal generation co-located with load. A socially optimal resource mix can be calculated using a co-optimized transmission and generation expansion model (CEP), a basic formulation for which is given in Appendix A. Both wind and thermal generation have a fixed cost that is linear in the installed capacity, and the thermal resource has an operating cost of $C_g^{EN} = \$40$/MWh. Transmission cost is modeled as an affine function of the line capacity, resulting in a decreasing average cost as the line size grows larger. The numerical examples use hourly demand and wind availability based on the ERCOT system in 2019. The value of lost load is set to the $B = \$9,000$/MWh assumption used by ERCOT prior to Winter Storm Uri in February 2021.

Figure 1 shows the optimal configuration of the system at different values for the capacity cost of the wind resource, holding demand, wind availability, and the cost of the thermal resource and transmission constant. As the cost of wind falls, the optimal capacity mix shifts toward higher levels of wind generation. While the optimal level of transmission grows with wind, it does not track the installed capacity precisely. Instead, the optimal ratio of transmission to wind falls as the quantity of wind grows and the system accepts higher levels of curtailment. At the optimal system configuration, the marginal cost of adding to transmission capacity is equal to the congestion cost observed in the system. Congestion results in a price separation of \$40/MWh between the two nodes, i.e., the difference in operating cost between the wind and thermal resources. The variable component of the transmission investment cost in the example is set to $K_l^V = \$10,000$/MW-year, implying that the line should be congested for 250 hours of the year. At low levels of wind, the optimal level of transmission can thus be calculated by finding the $(8760 - 250)/8760 = 0.972$ quantile of the wind production distribution. As wind begins to grow, however, its production can at times exceed the total demand in the system, leading to times with high wind output but no transmission congestion: the price at the load bus drops to \$0/MWh and wind is curtailed due to the system-wide economics rather than the transmission constraint. Since it is still optimal for the line to be congested for 250 hours, the transmission capacity drops to lower quantiles of the wind production distribution.

The primary consequence of this effect is that if interconnection study processes assume that variable resources must be able to inject their full capacity, they are likely to recommend inefficiently large network upgrades to accommodate new variable generators. An insistence on full deliverability is particularly problematic for storage and hybrid resources [51]. Recognizing this inefficiency, FERC Order 845 moved to allow projects to request interconnection service below their nameplate capacity [52]. The order, however, introduces another potential inefficiency by limiting subsequent injections from those resources to their requested service level. If resources were constrained based on actual system conditions rather than pre-curtailed by their interconnection agreement, they might be reliably dispatched between the level of their interconnection service and nameplate capacity. The potential for missed opportunities is likely to grow over a project's lifetime as the system moves farther from the conditions under which initial interconnection studies were performed.

III. De-Risking Interconnection with Financial Interconnection Rights

Since the beginning of competitive wholesale electricity markets, it has been recognized that complete reliance on short-term access to transmission service through economic dispatch is insufficient to the needs of investors in long-term assets [32]. Instead, generators need to secure long-term transmission rights allowing them to deliver the power they produce. In U.S. markets, recent trends in power procurement have heightened the need for this security, particularly for renewable generators. Early contracts between renewable plants and utilities, often signed to fulfill renewable portfolio standards, typically defined the delivery point as the location of the plant. Since utilities have experience with and control over transmission in their service territory, they were able to absorb congestion risk associated with the contract. More recently, renewable projects have increasingly relied on offtake agreements with corporate buyers settling at hub prices [53]. Commodity exchanges allowing further hedging of exposure to spot prices similarly operate only at trading hubs. The innovation of [32] was to replace the "contract path fiction," which defined physical rights that did not correspond to physical flows, with a financial right to send power across a network. The available evidence, however, suggests that existing FTR markets have not enabled the long-term firm

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transmission rights envisioned in [32]. The typical timing of auctions for FTRs, as well as the tenor on which rights are defined, do not meet the needs of project finance.

In this context, there is a way in which barriers to entry posed by the interconnection process serve to de-risk investment in new generation: since today's entrants become tomorrow's incumbents, the fact that future competitors will undergo a similar process constitutes an implicit promise, though not a guarantee, that power produced by a new project will be physically deliverable throughout its life. In other words, the interconnection process serves to provide some assurance that generated power will have some value without providing any associated right to be dispatched. This assurance is partially codified in the form of CIRs for generators that undergo a deliverability assessment. In principle, capacity markets attempt to recreate the revenues that resources would obtain in an idealized energy-only market [54]. Suppose an idealized market would produce a zonal average price of $60/MWh, while the market actually produces a zonal average energy price of $40/MWh and a capacity payment amounting to $20/MWh. Suppose the idealized nodal price seen by a particular resource would be $50/MWh, while it actually sees a nodal price of $35/MWh. A CIR gives this example resource a right to capacity revenues of $20/MWh, more than the $15/MWh in additional revenues they would earn in an idealized market. Accordingly, the financial interpretation of a CIR is as a swap on the component of congestion affected by inefficient spot price formation; the interconnection study process and resulting network upgrades allow the system operator to limit the system's downside on this implicit swap. In necessarily imprecise financial terms, with CIRs the system operator provides the interconnecting resource with a partial, poorly defined hedge against basis risk between its nodal price and the zonal price, with the risk of non-deliverability socialized to buyers of capacity.

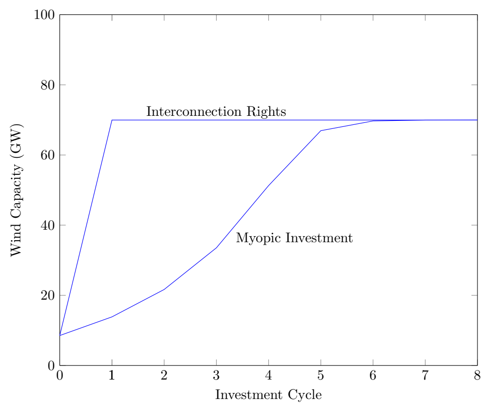
A moderate reform that streamlined interconnection and removed network upgrades would help de-risk overall project risk for interconnecting generator due to faster connection with less cost uncertainty. However, without an accompanying process for network expansion, new generators would be subject to 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. This reassignment can be accomplished by including a well-defined financial instrument as part of the interconnection process. Recognizing the connection to existing FTRs and CIRs, this paper labels the instrument a FIR. The primary difference from current FTRs is that rather than being tied to the current network, an approach that may be ill-suited to a situation in which ambitions for decarbonization are likely to require substantial expansion of the transmission network, this paper defines transmission rights as a purely financial instrument. The primary difference from current CIRs is that the proposed instrument would have a formal financial definition.

The proposed FIRs are straightforward to describe, but determining the specific attributes of contracts for each resource in the system leaves more room for discussion. Anticipating the numerical example, an FIR suited to the wind resource in the two-bus example above is defined in Appendix E. The goal of the FIR modeled in the example is to yield, neglecting the upfront fee, operating profits equal to what would be earned based on prices and dispatch in a fictional copper-plate system rather than the actual system. While such an equivalence cannot be guaranteed in a general way, numerical tests confirm that it holds on the two-node system used in the numerical example. Larger experiments are needed to validate that the form of the contract proposed here approximates the target revenue in more realistic cases. Six attributes define the instrument: the source node, the sink node, the shape, the tenor, the premium, and the counterparty. Of these, the source node is the simplest, since it is the location of a generator on the network. A natural proposal for the sink node would be the closest trading hub to the project. However, this choice could leave the counterparty of the contract with substantial downside risk if generation expansion occurs at a much greater pace than transmission expansion. An alternate choice would be a fictional node, e.g., prices calculated in an auction that used a "copper-plate" or zonal model of the transmission system, as in current capacity markets. With this alternate choice, expansion of supply would depress the value of the contract even if transmission could not be built, providing a safeguard for counterparties. Shapes could be determined to approximate the interconnecting generator's production profile. As discussed in [55], there is little reason to expect a fixed volume contract to provide a good hedge for variable generators. Instead, a natural choice would be to define the volume according to a proxy generation calculation, i.e., the amount a resource should be able to produce based on wind or solar availability. The tenor could be as long as the entire project life, while a shorter duration would provide less certainty for projects but less risk for counterparties. The premium, which amounts to a fee for interconnection, would be based on expected revenues from the swap and could be positive or negative depending on the location on the network. Last and potentially most contentious is the counterparty, i.e., the entity that absorbs the congestion risk that would otherwise be held by the generator. From an economic standpoint, it would be appropriate to assign this risk to incumbent transmission owners, such that they would have an incentive to reduce congestion as long as doing so was less expensive than taking losses on the contracts.

IV. Coordinating the Transition

To see why a shift from the current interconnection process to a system based on FIRs could be advantageous in the context of a transition to carbon-free resources, consider the two-bus system described above. Suppose that the system is optimally configured for a wind capacity cost of $C_g^{INV} =$ $200/kW-year, with a transmission capacity of 8,162 MW and wind providing 10.8% of annual energy. A sudden shift reduces the wind capacity cost to $C_g^{INV} =$ $60/kW-year, which implies an optimal long-run equilibrium wind capacity of 69,965 MW providing 70.8% of annual energy. While the

Fig. 2: Speed of transition after change in costs. With Financial Interconnection Rights, the system transitions to an optimal mix within one cycle of generation investment and transmission expansion.



numerical example is stylized, it mimics the present situation, in which plans for low-cost decarbonization typically include a substantial role for variable renewables that until recently were marginal contributors to most systems. Given that the present system is far from equilibrium, one question is how quickly decentralized investment in generation and centralized transmission expansion processes can shift to a system built around clean technologies.

Figure 2 compares the speed of transition between two potential approaches, demonstrating the potential benefit of replacing the current interconnection regime with one based on FIRs. The "myopic investment" case describes the status quo. In each investment cycle, generators expand or retire capacity based on the currently available transmission capacity, then transmission planners expand the network based on the current generation capacity mix. Models (GEP) and (TEP) describing the generation and transmission expansion planning are provided in Appendix B. After 6 cycles, the system converges on a new optimal configuration. With the introduction of FIRs, the generation problem of which is the situation changes. In the example, remote wind pays a fixed interconnection fee of \$3,156/kW-year while proximal thermal pays \$1,608/kW-year, after which both earn revenue based on prices that would be seen in a copper-plate system. Since the pricing of the instrument is based on projected long-term congestion rather than the existing transmission capacity, investors in generation immediately expand to an optimal mix in the first investment cycle. The generation expansion problem with a FIR is described in the Appendix F as model $(CU-GEP)$. Transmission planners respond by constructing an optimal transmission capacity in a single stage, rather than incremental additions in each cycle.

V. Conclusion

Liberalized electricity markets struggle to coordinate between decentralized investment in generation and centralized transmission planning. While market designers have long recognized the potential for inefficiency resulting from a lack of coordination, the scale of the problem has grown substantially as systems shift toward increased reliance on variable and geographically remote renewable resources. Generators hoping to interconnect to systems throughout the U.S. have encountered substantial delays and cost uncertainty, while network upgrades prompted by interconnection are plagued by myopia and cost socialization. As a result, the current interconnection process results in economic loss in at least two ways, as a barrier to entry for new generators and as a mechanism for inefficient transmission investment.

This paper describes the economic and cost allocation issues with the "connect and manage" and "invest and connect" approaches to interconnection, ultimately arguing for the former. Beyond this discussion, the paper develops a straw proposal in which generators pay an upfront fee in exchange for a contract limiting their exposure to price risk associated with their location on the network. The example illustrates why the proposed reconfiguration of the interconnection process has a major advantage in terms of the speed of deployment of new technologies. While the straw proposal described here leaves many design details and expanded numerical tests to further research and discussion, it should be understood that the overall approach results in a shift of risk away from developers of generation to transmission owners. Depending on the pricing and allocation of the resulting contracts, the proposal could result in inefficient socialization of transmission costs. At the same time, the discussion in the previous sections describes the economic inefficiencies embedded in the current system.

While the economic consequences of a disconnected process may be small in near-equilibrium circumstances, policymakers in the U.S. and worldwide have set goals for achieving carbon-free electricity as quickly as 2035. Given the scale of generation and transmission investment required to accomplish such a transformation, achieving those goals under the status quo approach to generator interconnection may be impossible. While many challenges in design, stakeholder acceptance, and implementation remain, the proposal offers the potential to improve coordination between generation and transmission expansion and support an efficient transition to clean technologies.

Appendix

Nomenclature

Sets

$i \in \mathcal{N}$	Nodes
$l \in \mathcal{L}$	Transmission lines
$g \in \mathcal{G}$	Generators
$\mathcal{G}_i \in \mathcal{G}$	Generators at node $i \in \mathcal{N}$
$t \in \mathcal{T}$	Time periods (hours)

Parameters

S_{il}	Node-arc incidence matrix element for node i and line l
B	Value of load (\$/MWh)
D_{it}	Demand bid quantity at node i in hour t (MWh)
C_g^{INV}	Annualized investment cost for generator g (\$/MW)
C_g^{EN}	Marginal cost for generator g (\$/MWh)
K_l^F	Fixed annualized investment cost for line l (\$)

K_l^V Size-dependent annualized investment cost for line l (\$/MW)
A_{gt} Availability of generator g in hour t (%)

Variables

x_g Installed capacity of generator g (MW)
y_{gt} Production by generator g in hour t (MWh)
z_l Installed transmission capacity on line l (MW)
f_{lt} Flow on line l in hour t (MW)
d_{it} Demand served at node i in hour t (MWh)

A. Generation and Transmission Co-optimization

The joint generation and transmission expansion problem is formulated as a deterministic linear program that maximizes the total surplus over the course of one year of operations after accounting for an annualized investment cost for both generation and transmission. Power flow is simplified to a transportation model. Reflecting the declining average costs typical of transmission infrastructure, transmission cost consists of fixed and size-dependent components. While this cost structure generally necessitates a mixed-integer program, we make the assumption that it is always optimal to build some amount of transmission in the included corridors in the range of costs considered, allowing a simplification to the linear model.

The joint generation and transmission expansion problem is stated as follows:

$$(CEP)$$

$$\begin{aligned}
\underset{x,y,z,f,d}{\text{maximize}}\quad & \textstyle\sum_{i\in\mathcal{N}}\sum_{t\in\mathcal{T}} B(d_{it}-D_{it}) - \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}} C_g^{EN} y_{gt} \\
& - \sum_{g\in\mathcal{G}} C_g^{INV} x_g - \sum_{l\in\mathcal{L}} (K_l^F + K_l^V z_l) && \text{(1a)}\\
\text{subject to}\quad & d_{it} - \sum_{g\in\mathcal{G}_i} y_{gt} + \sum_{l\in\mathcal{L}} S_{il} f_{lt} = 0 && \forall i\in\mathcal{N}, t\in\mathcal{T} \quad \text{(1b)}\\
& -z_l \le f_{lt} \le z_l && \forall l\in\mathcal{L}, t\in\mathcal{T} \quad \text{(1c)}\\
& 0 \le y_{gt} \le A_{gt} x_g && \forall g\in\mathcal{G}, t\in\mathcal{T} \quad \text{(1d)}\\
& 0 \le d_{it} \le D_{it} && \forall i\in\mathcal{N}, t\in\mathcal{T} \quad \text{(1e)}\\
& x_g \ge 0 && \forall g\in\mathcal{G} \quad \text{(1f)}\\
& z_l \ge 0 && \forall l\in\mathcal{L}. \quad \text{(1g)}
\end{aligned}$$

While formulated as a maximization problem, constants reflecting the value of firm demand and the fixed component of transmission cost are included, allowing the objective function in Eq. (1a) to be interpreted as the negative total cost to build and operate the system, including the cost of shedding load when necessary. With the node-arc incidence matrix element S_{il} taking the value 1 for a line originating at i, -1 for a line terminating at i, and 0 otherwise, Eq. (1b) represents power balance at each node. Equation (1c) enforces maximum flow on each line in each period, while Eq. (1d) limits generation to its available capacity in each period. Lastly, Eq. (1e) constrains the quantity of served load.

B. Myopic Investment

In the myopic case, investors in generation expand capacity to an optimal quantity based on the current transmission capacity in the system, while the transmission system planner builds based on the current generation capacity. Both processes are modeled as deterministic linear programs, and the order is chosen such that within each cycle generation investment occurs before transmission. With z_l^k representing the capacity of line l at the end of investment cycle $k \in \mathcal{K}$, the generation expansion problem for cycle $k+1$ is stated as follows:

$$(GEP)$$

$$\begin{aligned}
\underset{x,y,f,d}{\text{maximize}}\quad & \sum_{i\in\mathcal{N}}\sum_{t\in\mathcal{T}} B(d_{it}-D_{it}) \\
& - \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}} C_g^{EN} y_{gt} - \sum_{g\in\mathcal{G}} C_g^{INV} x_g && \text{(2a)}\\
\text{subject to}\quad & \text{(1b), (1d)–(1f)} \\
& -z_l^k \le f_{lt} \le z_l^k \quad \forall l\in\mathcal{L}, t\in\mathcal{T}. && \text{(2b)}
\end{aligned}$$

With x_g^k representing the installed capacity of technology g in cycle k, the transmission expansion problem in cycle k is stated as follows:

$$(TEP)$$

$$\begin{aligned}
\underset{y,z,f,d}{\text{maximize}}\quad & \sum_{i\in\mathcal{N}}\sum_{t\in\mathcal{T}} B(d_{it}-D_{it}) \\
& - \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}} C_g^{EN} y_{gt} \\
& - \sum_{l\in\mathcal{L}} (K_l^F + K_l^V z_l) && \text{(3a)}\\
\text{subject to}\quad & \text{(1b), (1c), (1e), (1g)} \\
& 0 \le y_{gt} \le A_{gt} x_g^k \quad \forall g\in\mathcal{G}, t\in\mathcal{T}. && \text{(3b)}
\end{aligned}$$

C. Dispatch Model

The dispatch model produces spot prices in each time period at each node, regardless of whether the generation and transmission capacity in the system are optimal. With $\hat{x}$ representing the current generation capacity and $\hat{z}$ the current transmission capacity, the economic dispatch problem is stated as follows:

$$(ED)$$

$$\begin{aligned}
\underset{y,f,d}{\text{maximize}}\quad & \textstyle\sum_{i\in\mathcal{N}}\sum_{t\in\mathcal{T}} B(d_{it}-D_{it}) - \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}} C_g^{EN} y_{gt} && \text{(4a)}\\
\text{subject to}\quad & d_{it} - \sum_{g\in\mathcal{G}_i} y_{gt} + \sum_{l\in\mathcal{L}} S_{il} f_{lt} = 0 && \forall i\in\mathcal{N}, t\in\mathcal{T} \quad \text{(4b)}\\
& -\hat{z}_l \le f_{lt} \le \hat{z}_l && \forall l\in\mathcal{L}, t\in\mathcal{T} \quad \text{(4c)}\\
& 0 \le y_{gt} \le A_{gt} \hat{x}_g && \forall g\in\mathcal{G}, t\in\mathcal{T} \quad \text{(4d)}\\
& 0 \le d_{it} \le D_{it} && \forall i\in\mathcal{N}, t\in\mathcal{T}. \quad \text{(4e)}
\end{aligned}$$

D. Copper Plate Model

In the numerical example, the proposed FIR is settled against the price that would arise in a copper plate system, i.e., one without transmission constraints. The copper plate dispatch problem given generation capacity $\hat{x}$ is stated as follows:

$$
\begin{aligned}
&(CU-ED)\\
&\underset{y,d}{\text{maximize}} \quad \sum_{i\in\mathcal{N}}\sum_{t\in\mathcal{T}} B(d_{it}-D_{it}) - \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}} C_g^{EN} y_{gt} && (5a)\\
&\text{subject to} \quad \sum_{i\in\mathcal{N}} d_{it} - \sum_{g\in\mathcal{G}} y_{gt} = 0 \qquad \forall t\in\mathcal{T} && (5b)\\
&\qquad 0 \le y_{gt} \le A_{gt}\hat{x}_g \qquad \forall g\in\mathcal{G}, t\in\mathcal{T} && (5c)\\
&\qquad 0 \le d_{it} \le D_{it} \qquad \forall i\in\mathcal{N}, t\in\mathcal{T}. && (5d)
\end{aligned}
$$

E. Financial Interconnection Rights

As defined in this paper, a generator that holds a FIR has an option on the difference between the price that would arise in a copper plate model and the spot price at their location, with the volume scaled by the availability of that generator. Along the lines of the discussion in [55], this definition is appropriate for the variable renewables driving current issues in interconnection processes; however, alternative definitions of the hedging instrument could be constructed for thermal resources, storage, and demand-side resources as appropriate. Letλ_{it} indicate the price at node i in time period t, calculated as the dual variable to the power balance constraint in model (ED), and let λ_t^{CU} indicate the dual variable to the power balance constraint in the copper plate model $(CU-ED)$. Then, the per-MW payout r_g of a FIR for generator g located at node i is calculated as

$$r_g = \sum_{t\in\mathcal{T}} A_{gt}\max\{0, \lambda_t^{CU} - \lambda_{it}\}. \qquad (6)$$

Note that the volume of the contract is determined by the availability of the resource, rather than the amount actually produced in real-time given a potentially suboptimal generation mix or transmission configuration. Accordingly, the contract does not affect dispatch incentives on the margin. For the numerical experiment, the price q_g of the instrument per MW of installed capacity (i.e., the fixed interconnection fee) is calculated as

$$q_g = \sum_{t\in\mathcal{T}} A_{gt}\max\{0, \lambda_t^{CU^*} - \lambda_{it}^*\}, \qquad (7)$$

where values for λ_{it}^* are calculated as the dual variables to Eq. (1b) from model (CEP) and those for $\lambda_t^{CU^*}$ are calculated using model $(CU-ED)$ and the optimal generation mix from model (CEP). It follows that, with perfect information and an optimally configured generation mix and transmission system, the price and payout of the contract would be precisely equal.

It is worth highlighting that the definition here relies on the presence of full-strength nodal prices for energy. In a system with zonal capacity markets, the hedge would also need to include the financial component of a CIR. While a CIR grants the right to participate in the capacity market (based on a deliverability assessment performed upon interconnection), an FIR would provide a swap on revenues in the capacity market even if a unit were deemed non-deliverable in a later, more accurate assessment.

F. Equilibrium Generation Mix

A long-run competitive equilibrium generation mix for a given transmission configuration occurs when a) spot prices match supply and demand at each node in each time period, i.e., the short-term market clears, and b) each generation resource with non-zero capacity in the system achieves zero profit. Suppose $(x^*, y^*, z^*, f^*, d^*)$ is an optimal solution to model (CEP). Then, given the linear programming form of model (CEP), it is well-known that x^* is an equilibrium generation mix. Now consider a modified copper-plate generation expansion problem formulated as follows:

$$
\begin{aligned}
&(CU-GEP)\\
&\underset{x,y,d}{\text{maximize}}\\
&\textstyle\sum_{i\in\mathcal{N}}\sum_{t\in\mathcal{T}} B(d_{it}-D_{it}) - \sum_{t\in\mathcal{T}}\sum_{g\in\mathcal{G}} C_g^{EN} y_{gt}\\
&-\sum_{g\in\mathcal{G}}(C_g^{INV}+q_g)x_g && (8a)\\
&\text{subject to}\\
&\sum_{i\in\mathcal{N}} d_{it} - \sum_{g\in\mathcal{G}} y_{gt} = 0 \qquad \forall t\in\mathcal{T} && (8b)\\
&0 \le y_{gt} \le A_{gt}x_g \qquad \forall g\in\mathcal{G}, t\in\mathcal{T} && (8c)\\
&0 \le d_{it} \le D_{it} \qquad \forall i\in\mathcal{N}, t\in\mathcal{T}. && (8d)
\end{aligned}
$$

Comparing to model (GEP), the investment cost C_g^{INV} has been adjusted by the cost of the FIR, q_g, and transmission constraints have been relaxed. As a linear program, prices equal to the dual variables associated with Eq. (8b) lead to zero profit for all generators in the optimal solution to model $(CU-GEP)$. Assuming the FIR achieves its goal of exchanging operating profits under nodal prices for operating profits that would be obtained in a copper-plate system, payouts from the contract precisely balance the additional charge q_g, implying that x^* is also a zero-profit equilibrium under the proposed regime. As a consequence, model $(CU-GEP)$ can be solved to find the equilibrium generation mix that would be obtained with FIRs, and (neglecting complications with multiple optimal primal or dual solutions) this generation mix is socially optimal for the socially optimal transmission system.

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