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Financing the U.S. Electricity Grid Expansion: Investment Barriers and Innovative Capital Structures

Experience Efeosa Akhigbe*

Independent Researcher, USA

Abstract

The United States needs substantially more transmission capacity than it has built in recent decades, yet financing that expansion is harder than financing most generation assets. Transmission projects have long construction periods, costs shared among many beneficiaries, and revenues set by regulators or contract rather than by market prices. This paper examines the investment barriers that constrain transmission and grid-related capital formation in the United States and assesses the capital structures proposed or adopted to address them. It classifies five barrier categories (cost-recovery lag, merchant revenue risk, interconnection timing, construction risk, and cross-jurisdictional allocation) and evaluates four classes of capital structure against the federal record and recent projects. An illustrative calculation shows that a two-percentage-point increase in the interest rate on a 1-billion-dollar, 30-year loan raises annual debt service by about 15.5 million dollars. The analysis finds that the binding constraints are institutional as much as financial. The termination of the conditional federal financing commitment for the Grain Belt Express project in July 2025 illustrates how reversible federal support can be. Durable grid finance therefore depends on aligning cost recovery, risk allocation, and federal commitments with the multi-decade life of grid assets.

Keywords: Transmission investment; grid expansion; infrastructure finance; loan guarantees; tax credit transferability; cost recovery.

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Introduction

Electricity transmission is the connective tissue of the power system. It moves generation from where resources are located to where demand exists, it allows regions to share reserves and absorb shocks, and it is the means by which new generation of any kind reaches customers. The United States has an extensive transmission network, but the pace of new construction has not kept up with the changes now reshaping the system. The Department of Energy's National Transmission Needs Study, released in October 2023, assessed transmission needs through 2040 and identified substantial and growing requirements for new capacity, with particular emphasis on interregional transfers (U.S. Department of Energy, 2023). The study also identified the Midwest, the Great Plains, and Texas as regions where demand for new transmission infrastructure is greatest (Perkins Coie, 2023). Joskow (2019) makes the case that transmission capacity expansion is needed to decarbonize the electricity sector efficiently.

Meeting these needs requires capital, and the sources of that capital are not well matched to the characteristics of transmission. A high-voltage line may take many years to permit and build, may generate benefits for a broad population, and may earn revenue that is set administratively rather than by the market for the electricity it carries. Investors who are accustomed to shorter-lived, contracted generation assets may find these attributes unfamiliar. Public utilities, which have historically built most transmission, are subject to state and federal rate regulation that determines when and how their investments can be recovered. Independent developers, which have grown in number and ambition, face merchant revenue risk and regulatory uncertainty about whether their projects will be allowed to recover costs at all. A separate paper addresses the project-level readiness conditions that apply to generation assets. This paper concentrates on network assets and on the institutional arrangements that support their financing.

Corresponding Author: Experience Efeosa Akhigbe, Independent Researcher, USA, e-mail: experienceakhigbe@yahoo.com

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This paper asks two related questions. The first is what the principal investment barriers to grid expansion are, and how they differ across the institutional settings in which transmission is developed. The second is which capital structures have been proposed or adopted to overcome those barriers, and how well they respond to the specific risks involved. The analysis is organized around these two questions. Section 2 reviews the economics of transmission investment and the policy context in the United States. Section 3 identifies five barrier categories and illustrates each with evidence from the federal record and from recent projects. Section 4 evaluates capital structures in four classes. Section 5 discusses the implications for policymakers, developers, and investors. Section 6 concludes.

The paper contributes in three ways. It provides a classification of barriers that links each to a specific financing consequence. It assesses capital structures against the barrier each is designed to address, which reveals gaps in the current toolkit. And it illustrates, with an explicit calculation, how financing costs translate into annual burdens for large projects. Throughout, the analysis treats the institutional environment as a financing variable. The Federal Energy Regulatory Commission's interconnection rules, the Inflation Reduction Act's tax-credit transferability provisions, and the federal loan guarantee program of the Department of Energy each shape the terms on which grid assets can be financed, and each has changed in ways that matter for the analysis.

Background and Context

The economics of transmission investment

Transmission is usually described as a natural monopoly, because a single network can serve a region more efficiently than several competing networks. This characteristic has shaped its regulation. In the United States, transmission owners that are subject to federal jurisdiction have traditionally recovered their costs through regulated rates set on the basis of a rate base, a return on invested capital, and an allowed return on equity. Under this model, the investor's revenue is a function of the investment the regulator approves, not of the market price of electricity. Cost recovery is therefore relatively predictable, but it depends on the regulator's willingness to approve projects and on the timing of rate cases. Adenuga (2022) reviews smart grid architectures for high renewable penetration and finds that financing gaps and institutional realities determine which architectures can be deployed, particularly in developing regions. Shittu, Adaramola and Shittu (2025) review automation and management strategies intended to improve grid operating performance.

An alternative model has been advanced in the economics literature. Joskow and Tirole (2005) examined a merchant transmission investment framework in which independent investors build lines and earn revenue from congestion rents and from the value of transmission rights, without regulated cost recovery. Their analysis showed that the merchant model is attractive under a stringent set of assumptions, but that relaxing those assumptions, to incorporate market power in wholesale electricity markets, lumpiness in investment opportunities, and strategic behavior by potential investors, leads to inefficient transmission investment. The conclusion is important for finance because it suggests that merchant revenue risk is not merely a matter of investor appetite. It reflects structural features of the market that can prevent efficient investment from occurring.

Joskow and Tirole (2007) extended this analysis to reliability and to the non-market mechanisms that competitive electricity markets have adopted, including price caps, capacity obligations, and operating reserve requirements. Their work, published in the RAND Journal of Economics in 2007, emphasized that the reliability of the network depends on decisions that are not fully captured by energy prices. For grid finance, this implies that revenues from transmission investment may depend on regulatory choices about reliability standards and cost allocation, which in turn determine whether a line is financeable on the terms investors require.

The economics of transmission investment starts from the observation that grid assets are lumpy and shared. Joskow (2005) reviews the development of U.S. transmission access, pricing and investment policy and assesses how those rules shaped incentives to build. Joskow and Tirole (2005) examine whether merchant transmission, financed by investors who bear market risk, can supply the required capacity, and conclude that the merchant model leaves significant inefficiencies in place. Hogan (1992) proposed a contract network that assigns long-term capacity rights across a complicated transmission network, and Bushnell and Stoft (1996) find that, under certain conditions, such a regime deters detrimental investments that other regimes encourage, although market participants may still make detrimental network alterations when those conditions fail.

Literature on real options formalizes the delay that these risks produce. Yang, Blyth, Bradley, Bunn and Clarke (2008) show that climate policy uncertainty raises the option value of waiting for power investors, and Fernandes, Cunha and Ferreira (2011) review the wider application of real options in energy investment. Applied to transmission, the same logic implies that merchant revenue risk does not merely raise the required return; it shifts the timing of investment, which compounds the interconnection timing barrier examined in the next subsection.

Subsequent scholarship has extended this economics of transmission in two directions. Macey and Mays (2024) provide a law-and-economics treatment of transmission planning and cost allocation, documenting how competitive interactions among states and utilities undermine investment that would benefit the interconnected system. Chao and Wilson (2020) analyse the coordination of electricity transmission and generation investments, showing how joint

optimization changes the financeability of both legs. Hogan (2018) develops a primer on transmission benefits and cost allocation that grounds the beneficiaries-pays principle used in practice, and Haro, Moreno, Munoz et al. (2025) provide an equilibrium analysis of transmission cost allocation and its efficiency and environmental trade-offs. Zheng, Schivley, Fripp and Roberts (2026) estimate that optimal transmission expansion modestly reduces the decarbonization cost of the U.S. electricity system, and Simeone and Rose (2024) catalogue the barriers and opportunities for realizing the system value of interregional transmission. Botterud et al. (2024) quantify the impact of interregional transmission on emissions and reliability under current policies and deep decarbonization.

The capacity problem and the missing money

A related literature addresses the adequacy of revenues in wholesale electricity markets. Joskow (2008) argued that a variety of imperfections in energy-only markets lead generators to earn net revenues that are inadequate to support investment in a least-cost portfolio of capacity and to satisfy consumer preferences for reliability. He called this the missing money problem. Although Joskow's analysis concerned generation capacity rather than transmission, the mechanism is directly relevant to grid finance. Where market revenues do not capture the full value of infrastructure, investors require supplementary revenue or regulatory certainty, and the design of those supplements becomes a central financing question.

Joskow proposed forward capacity obligations and associated auction mechanisms as remedies. The analogy to transmission is imperfect, because transmission lines do not compete with one another in the same way generators do, but the underlying point carries over. Grid assets generate value that is not fully reflected in the revenue streams available to their owners, including reliability, resilience, and the ability to integrate new resources. A financing structure that captures only a part of this value will underinvest, and the remedy is either a revenue mechanism that captures it or a cost-recovery framework that allows the owner to recover costs from the beneficiaries.

The demand-side counterpart of the capacity problem has grown more important as load growth returns. Tsuchida et al. (2024) describe the forecasting difficulty facing planners in a period of structural change, and Wilson, Meyer, Zimmerman et al. (2025) document that national power demand forecasts have been revised upward for three consecutive years, led by data centers. Chen, Zhou, Cai, Qin, Katchova et al. (2026) estimate that artificial-intelligence data centers could reach roughly one percent of global electricity demand by 2030. Rising demand raises the value of timely transmission and simultaneously raises the cost of the institutional delays documented in Section 3, because foregone capacity now carries a reliability price as well as an economic one.

The capacity problem is also a problem of resource mix. Brown and Botterud (2021) find that interregional coordination and transmission expansion can substantially reduce the cost of a decarbonized U.S. grid relative to states pursuing their own goals in isolation. MacDonald et al. (2016) report that a national system linked by high-voltage direct-current lines, with wind and solar generation, could reduce power-sector carbon dioxide emissions substantially without raising the levelized cost of electricity. Clack, Xie and MacDonald (2015) apply linear programming to optimize an electrical system that includes high-voltage direct-current transmission and storage. Sepulveda et al. (2018) show that firm low-carbon resources lower the cost of deep decarbonization in most cases, so the revenue case for a new line depends partly on the resources it connects.

The federal policy context

The policy context for grid finance changed substantially in the early 2020s. The Inflation Reduction Act of 2022 created new tax-credit provisions for clean electricity generation and for clean energy investment, and it allowed taxpayers to transfer many of those credits to unrelated parties under section 6418 of the Internal Revenue Code (Public Law 117-169, 2022). Transferability applies to taxable years beginning after December 31, 2022, and the Treasury Department and the Internal Revenue Service issued final regulations governing the election on April 30, 2024 (Internal Revenue Service and Department of the Treasury, 2024). These provisions are primarily aimed at generation and storage, but they affect transmission finance indirectly, because the generation that transmission serves becomes more financeable when its tax credits can be monetized.

The Federal Energy Regulatory Commission has also reformed interconnection rules. Order No. 2023, issued on July 28, 2023, replaced the serial interconnection study process with a cluster-based approach and imposed financial commitments on interconnection requests (Federal Energy Regulatory Commission, 2023). The Commission clarified the rule in Order No. 2023-A on March 21, 2024 (Federal Energy Regulatory Commission, 2024b). Interconnection reform is distinct from transmission planning, but it shapes the grid investment environment because new generation requires network upgrades, and the timing of those upgrades affects whether generation projects can be financed and whether associated transmission can be recovered.

The Department of Energy's Loan Programs Office provides a third element of federal policy. The office can issue loan guarantees to projects that meet statutory criteria, and it has used this authority for energy infrastructure, including transmission. The Grain Belt Express project, discussed in Section 4.2, is the most prominent recent example, and its experience illustrates both the value and the fragility of federal support for grid finance.

The statutory basis for the Needs Study also matters for the financing argument. The study is a product of Section 216(a)(1) of the Federal Power Act, which directs the Department of Energy to identify transmission capacity constraints and congestion that harm consumers or that are expected to do

so, and to identify needs that transmission solutions could alleviate (U.S. Department of Energy, 2023). The study is therefore designed as a diagnostic instrument rather than as a financing plan. It establishes where transmission is needed, but it does not determine who will pay for the lines, how the revenue will be secured, or which capital structure will carry the risk. The gap between diagnosis and finance is the subject of the remainder of this paper.

Federal policy has shaped this market through successive rulemakings. FERC's Order No. 679 (Federal Energy Regulatory Commission, 2006) established incentive-based rate treatments for transmission investment under the Energy Policy Act of 2005. Order No. 1000 (Federal Energy Regulatory Commission, 2011) required regional planning and cost allocation, and Order No. 1920 (Federal Energy Regulatory Commission, 2024a) substantially expanded long-term regional planning. The Infrastructure Investment and Jobs Act (U.S. Congress, 2021) and the Department of Energy's National Transmission Planning Study (U.S. Department of Energy, 2024) supplied new funding and planning analysis for interregional lines, and the National Academies of Sciences, Engineering, and Medicine (2021) assess how the electric system may evolve and what funding and policy it will require.

Two further strands of the literature bear on this diagnostic gap. The first concerns permitting. Liscow (2025) reviews the law and economics of permitting and the duration of environmental review, Bennon and Wilson (2023) examine NEPA litigation over large energy and transport infrastructure, and Adelman (2024) analyses the procedural choices that determine how permitting reform performs in practice. Coleman (2024) and Adler (2024) examine the legal architecture of permitting for the energy transition, and Liu (2025) provides quantitative evidence linking permitting and litigation risk to slower energy infrastructure investment. Banet and Donati (2024) offer a European benchmark for renewable permitting reform. The second strand concerns the reliability baseline against which transmission adequacy is judged. The North American Electric Reliability Corporation's long-term assessment (2024) documents growing resource adequacy challenges, and Boff and Barrows (2023) provide a historical evaluation of interconnection policy that situates today's queue reforms in their institutional context.

Investment Barriers

Barrier classification

The analysis classifies investment barriers into five categories. The first is cost-recovery lag, which arises when the time between spending on a project and the recovery of that spending is long or uncertain. The second is merchant revenue risk, which arises when the owner's revenue depends on market prices or on congestion rents that may fall. The third is interconnection and queue timing, which arises when the schedule for connecting generation to the grid is out of step with the schedule for financing the transmission that supports it. The fourth is construction and schedule risk, which arises from the size, complexity, and duration of grid projects. The fifth is the allocation of benefits and costs across jurisdictions, which arises when a line that serves one region must be sited and paid for in another.

Table 1 summarizes the barrier categories, which follow the market-failure logic developed for transmission economics (Joskow and Tirole, 2005), the mechanism through which each affects financing, the asset types most exposed, and the evidence reviewed in this section. The categories are not mutually exclusive. A large interregional line may face all five at once, and their interaction is often what makes the project difficult to finance.

Resource adequacy adds a further dimension to these barriers. The North American Electric Reliability Corporation (2024) reports that most of the North American bulk power system faces growing resource adequacy challenges over the next decade, as demand growth accelerates and thermal generators announce retirements. A grid investment that is slow to finance therefore carries reliability costs as well as delay costs, which strengthens the case for the structures examined in Section 4.

The interaction of barriers with financing cost can also be stated in the language of corporate finance. Modigliani and Miller (1958; 1963) establish the benchmark from which the tax advantage of debt and the value of guarantees are

Table 1: Classification of investment barriers to grid expansion

Barrier category	*Financing mechanism*	*Most exposed assets*	*Principal evidence*
Cost-recovery lag	Delay between spending and rate recovery raises financing cost	Regulated transmission and network upgrades	Joskow and Tirole (2005; 2007)
Merchant revenue risk	Revenue depends on congestion rents and market conditions	Merchant and independent transmission lines	Joskow and Tirole (2005)
Interconnection and queue timing	Generation and transmission schedules diverge	Interconnection-driven upgrades and hybrid projects	FERC (2023; 2024); LBNL (2025; 2026)
Construction and schedule risk	Overruns and delays exceed the sponsor's capacity	Large interregional lines and new firm generation	Vogtle expansion (AJC, 2024; Georgia PSC, 2024)
Cross-jurisdictional allocation	Siting and cost allocation disputes delay or block projects	Interregional and multistate lines	DOE (2023); Grain Belt Express (ENR, 2025)

measured; Myers (1984) and Myers and Majluf (1984) explain why information asymmetry and financial hierarchy shape investment under uncertainty; Jensen and Meckling (1976) develop the agency costs that regulated cost recovery is designed to mitigate; and Harris and Raviv (1991) survey the resulting capital-structure models. Graham and Harvey (2001) provide survey evidence on how these theories map to practice. In the transmission setting, these theories imply that the institutional determinants of revenue quality, documented in the barrier analysis, are the principal levers through which capital structure affects feasibility.

Cost-recovery lag

Cost-recovery lag is the most familiar barrier in regulated transmission. A utility that invests in a line must finance the investment before it can include the asset in rates, and the period between spending and inclusion can be long. During that period the utility carries the financing cost of the investment, and if regulators disallow part of the cost, the utility bears the loss. The lag therefore increases the cost of capital for the investment and can make marginal projects uneconomic for the utility, even when the project would serve customers well.

The problem is compounded for projects that cross jurisdictions. A line that serves customers in several states may require approvals from multiple regulators, each with its own rate-case process and its own view of cost allocation. The sequencing of these approvals can extend the lag considerably. Developers that rely on regulated recovery must therefore plan for a financing period that may exceed the construction period itself, and they must hold capital through it. Projects with weak sponsors may be unable to do so.

Joskow and Tirole (2005) emphasized that the regulatory framework for transmission investment determines the efficiency of the outcome. Their analysis suggests that cost-recovery arrangements should be designed to align the incentives of investors with the value that the investment creates. A framework in which investors cannot recover costs in a timely manner will tend to underinvest, while a framework in which cost recovery is automatic may encourage overinvestment. The appropriate design depends on the regulatory environment, and the financing consequences of that design are substantial.

Merchant revenue risk

Merchant transmission lines earn revenue from the difference in electricity prices across locations, which is captured as congestion rent, or from the sale of transmission rights. The revenue is therefore exposed to the behavior of wholesale markets, the evolution of generation and load patterns, and the rules governing the allocation of rights. A merchant line that is built to carry power from a region with abundant low-cost generation to a region with high prices will earn revenue only as long as the price difference persists. If new generation is built near the load center, or if transmission rights are allocated in a manner that reduces the line's share of the rent, the revenue can fall sharply.

Joskow and Tirole (2005) showed that a merchant framework can produce inefficient investment decisions when it is combined with realistic features of transmission networks and wholesale markets. For financing, the implication is that merchant revenue cannot easily support project debt without contractual protection. Lenders will require either long-term capacity contracts with creditworthy counterparties, which convert merchant exposure into contracted revenue, or sponsor equity large enough to absorb the risk. Where neither is available, the project cannot be financed on merchant terms, and the investment is deferred or abandoned.

The experience of the Grain Belt Express project illustrates the point. Its developer, Invenergy, pursued a combination of private investment and federal support, and it sought to secure revenue through transmission service agreements with utilities and municipal buyers. The Department of Energy described the financial shortcomings of the project as unlikely to be resolved when it terminated the federal commitment in July 2025, and Engineering News-Record's review of regulatory filings found that the developer's voluntary transmission service agreements did not include binding long-term revenue commitments (Engineering News-Record, 2025). The case shows that merchant-style risk remains a binding constraint even for projects that are structured to reduce it.

Interconnection and queue timing

Transmission and generation are financed on different schedules, and the mismatch between them is a barrier in its own right. A generation project that has secured an interconnection position may need network upgrades before it can deliver power, and those upgrades may be financed by the transmission owner, by the generator, or by a combination. If the upgrades are not scheduled to coincide with the generator's construction, the generator may be unable to reach commercial operation on its planned date, and its financing may fail.

The scale of the queue makes this barrier severe. The Lawrence Berkeley National Laboratory's analysis of interconnection queues found that more than 2,060 gigawatts of generation and storage capacity were actively seeking connection at the end of 2025, and that only 13 percent of the capacity that submitted requests between 2000 and 2020 had reached commercial operation by that date (Berkeley Lab, 2026; Rand et al., 2025). The high rate of withdrawal indicates that many projects in the queue were not financeable, and that the queue process itself did not screen them efficiently. The Order No. 2023 reforms were intended to address this problem by replacing serial studies with clusters and by requiring financial commitments that increase as projects advance (Federal Energy Regulatory

Commission, 2023).

For transmission finance, the queue barrier means that the grid investment decision is linked to generation decisions that the transmission owner does not control. A transmission owner that builds ahead of demand may carry stranded assets. One that builds behind demand may delay generation and forfeit revenue. The resolution requires coordination between transmission planning and interconnection processes, and financing structures that allow owners to recover costs in a manner that reflects the timing of the generation they serve.

Construction and schedule risk

Large transmission and generation projects face construction risk that is greater in magnitude than most infrastructure assets. The cost and schedule of a project depend on equipment supply, labor availability, permitting, and the performance of contractors, all of which can change during a construction period that may last several years. The risk is most severe for projects that use new configurations or that are built at a scale without domestic precedent. Amayo, Owulade and Isi (2024) examine project governance in multinational infrastructure projects through a case study of General Electric, treating risk management and stakeholder engagement as central governance concerns.

The Plant Vogtle expansion in Georgia illustrates the consequences of construction risk for a large project. The two new reactors were originally estimated at about 14 billion dollars, and the total cost rose to around 35 billion dollars by the time the second unit entered commercial service on April 29, 2024 (Associated Press-Atlanta Journal-Constitution, 2024). Georgia Power's share of the total capital cost forecast remained approximately 10.2 billion dollars in its construction monitoring reports (Georgia Public Service Commission, 2024). Although Vogtle is a nuclear project rather than a transmission project, the lessons apply to large grid assets that depend on specialized equipment and on multi-year construction. A sponsor that cannot absorb overruns of this magnitude will be unable to finance the project, and a regulator that allows recovery of overruns will shift cost to customers.

The Vogtle case also illustrates a point about risk allocation. The cost increases were absorbed in part by the sponsoring utilities, in part through a parent guaranty from the reactor supplier (Echols, 2024), and in part through the rate base, with associated political consequences for customers. The mechanism for allocating overrun risk is therefore a financing variable as important as the construction contract itself. Transmission projects that lack a comparable allocation will face the same tension between investor protection and customer exposure.

Cross-jurisdictional allocation

The final barrier is the allocation of benefits and costs across jurisdictions. Interregional transmission generates value for regions that may not pay for it, and it imposes costs, including siting impacts and land use, on regions that may not benefit proportionately. The Department of Energy's National Transmission Needs Study emphasized the value of interregional transfers for reliability and for the integration of resources (U.S. Department of Energy, 2023). Realizing that value requires agreement on cost allocation among states, utilities, and other stakeholders, and such agreement is difficult to reach. Mai et al. (2026) review seven recent national studies and find that substantial transmission expansion appears in many future scenarios. Safavi et al. (2025) estimate that interregional electricity trade achieved savings of at least $1,226 million per year between 2014 and 2023, although uneconomic interchange offset an average of $551 million per year of that value.

The Grain Belt Express project is again instructive. It was designed as a high-voltage direct current line carrying wind and solar power from Kansas to population centers in the Midwest and East, and its planned capacity was described as five gigawatts across the full project, with a first phase of about 2.5 gigawatts (Enerdata, 2024; Enerdata, 2025). Securing the rights and approvals for a line that crosses several states involves regulatory processes in each state, and the allocation of cost among the beneficiaries requires contracts that span multiple utilities and municipal buyers. The project's financing therefore depended on the completion of commercial arrangements that were themselves difficult to structure, in addition to the financing of construction.

Cross-jurisdictional allocation thus converts a technical problem into a financial one. Each jurisdiction must be persuaded that the project's benefits exceed its costs to that jurisdiction, and each must have a mechanism for paying its share. Without such mechanisms, the investment cannot be structured on terms that lenders or equity investors will accept, regardless of its engineering merits.

Interaction among barriers

The five barrier categories are analytically distinct, but they interact in ways that can amplify their individual effects. Cost-recovery lag and merchant revenue risk reinforce one another. A merchant line that cannot recover its costs through rates must depend on market revenues whose timing is uncertain, and the longer the lag before revenue arrives, the greater the exposure to the market conditions that determine it. Joskow and Tirole (2005) identified a related form of compounding in their analysis of merchant investment, where strategic behavior and coordination problems among transmission owners and system operators produced inefficiencies that a simple revenue model would not predict.

Interconnection timing interacts with construction risk. A transmission upgrade delayed by queue congestion extends the construction period of the generation it serves, and each additional year of construction increases the exposure of both projects to equipment price changes and to shifts in policy.

The Berkeley Lab finding that only 13 percent of requests from 2000 to 2020 had reached operation illustrates the scale of the problem, since projects that stall in the queue accumulate development cost without generating revenue (Berkeley Lab, 2026). The Order No. 2023 cluster process is intended to reduce this compounding by studying requests together, but it does not eliminate the dependence of generation timing on transmission timing (Federal Energy Regulatory Commission, 2023).

Cross-jurisdictional allocation interacts with all of the others. Disagreement over cost allocation extends regulatory proceedings, which extends cost-recovery lag, and it weakens the negotiating position of developers seeking long-term contracts, which increases merchant exposure. A project that must win approval from several state regulators therefore faces the lag of each proceeding and the risk that one of them will reject the proposed allocation. The compounding means that the financing requirement of a large interregional line can exceed the simple sum of its individual barriers.

Empirical work on renewable energy investment determinants supports the view that these institutional variables, rather than the cost of capital alone, drive deployment. Aguirre and Ibikunle (2014), Ragosa and Warren (2019), Wall et al. (2019), and Kilinc-Ata and Dolmatov (2023) all find that policy quality and institutional conditions are significant determinants of renewable investment across countries, and Calcaterra et al. (2024) show that cost-of-capital reductions are among the most powerful available levers. Steffen, Egli, Gumber, Dukan and Waidelich et al. (2025) supply the global dataset of financing terms that makes such comparisons possible. For transmission, the analogous dataset does not yet exist, which is itself a finding recorded in Section 5.3.

For policymakers, the implication is that single-barrier remedies are likely to be insufficient. A reform that addresses cost recovery without addressing contracting or allocation may leave a project unfinanceable, and a federal guarantee that addresses construction risk without addressing revenue may simply defer the problem. The barriers must be treated as a system, and the sequence of reforms should reflect the order in which the barriers bind during development. Section 5.1 returns to this point in proposing a sequence.

Innovative Capital Structures

Framework for assessment

This section evaluates four classes of capital structure against the barriers identified in Section 3, several of which build on the project-finance logic described by Steffen (2018). The assessment asks three questions of each structure. The first is which barrier it addresses directly. The second is which risks it leaves with the sponsor, the lender, or the public. The third is how the structure performs under policy change, since the durability of a financing arrangement depends on the stability of the policy that supports it. The four classes are federal credit transferability, federal loan guarantees, regulated and hybrid rate-base models, and portfolio-level financing that aggregates grid and generation assets.

The theoretical foundations of regulated network finance extend well beyond this record. Vogelsang (2006) examines electricity transmission pricing and performance-based regulation as alternatives to traditional rate-base recovery, and Joskow (2014) reviews incentive regulation in theory and practice for electricity transmission and distribution networks, showing how regulatory design shapes both the level and the risk of allowed returns. Brunekreeft, Neuhoff and Newbery (2005) survey the transmission investment debate and identify the recurring tension between coordinated planning and investor incentives, while Brunekreeft and Meyer (2011) analyse regulatory risk in the face of large transmission investment directly. Werner and Jarvis (2025) provide recent empirical evidence on rate-of-return regulation using regulatory filings on individual utility capital spending, which quantifies how allowed returns and capital spending interact in practice.

The supply of long-horizon capital has its own literature, which matters because the financing problem of transmission is ultimately a matching problem between asset duration and investor horizon. Della Croce and Yermo (2013), Inderst (2009), and Kaminker et al. (2013) document the conditions under which pension funds, insurers, and other institutional investors supply infrastructure capital, and Carlo, Eichholtz, Kok and Wijnands (2023) show empirically how pension fund infrastructure programs are governed. Sartzetakis (2021) and Bhattacharyya (2022) describe the role of green bonds and green finance in mobilizing debt for low-carbon infrastructure at scale. These sources establish that capital exists in principle; the barriers examined in Section 3 explain why it does not always reach transmission in practice.

The assessment does not claim that any structure is universally superior. Each has advantages for some barriers and limitations for others. The purpose of the analysis is to show how the choice of structure should follow the binding barrier, and to identify where the current toolkit leaves gaps. Table 2 summarizes the assessment, and the subsections that follow discuss each class in turn.

Five criteria organize the discussion in Sections 4.2 to 4.5: financing cost, revenue certainty, regulatory exposure, implementation feasibility, and risk allocation. Each structure is examined against these criteria in the text. The assessment is qualitative. It assigns no numerical weights and does not rate the structures from transaction data. A weighted scoring matrix built on these criteria would be the natural next step, and it would require documented outcomes for each structure.

Federal loan guarantees and their fragility

The Department of Energy's Loan Programs Office can issue loan guarantees that reduce the cost of debt for qualifying projects. A guarantee lowers the lender's exposure to default,

Table 2: Capital structure options for grid expansion, barriers addressed, and binding limitations. Credit transferability acts indirectly, through the generation that it finances.

Structure	*Source of capital*	*Barriers addressed*	*Risks left with sponsor or public*	*Binding limitation*
Federal credit transferability (indirect)	Unrelated buyers of tax credits	Cost-recovery lag, partly	Credit eligibility and market price of transferred credits	Credits attach to generation and storage, not to transmission
Federal loan guarantee	Lenders backed by Department of Energy guarantee	Cost-recovery lag, construction risk	Public exposure to default; policy continuity	Conditional commitments can be withdrawn
Regulated rate base	Ratepayers through approved returns	Merchant revenue risk, cost-recovery lag	Regulatory disallowance; rate-case timing	Dependent on regulator approval and cost allocation
Hybrid merchant with contracted capacity	Contracted offtakers plus equity and debt	Merchant revenue risk, cross-jurisdictional allocation	Counterparty credit; merchant residual	Requires long-term capacity contracts that are scarce
Portfolio-level financing	Pooled capital across many assets	Construction risk, sponsor capacity	Correlated exposure across portfolio	Requires standardized assets and transparent performance

which can reduce the interest rate and extend the tenor of the loan. For grid projects, which require large amounts of long-term debt, the reduction can be substantial. The mechanism addresses cost-recovery lag and construction risk in part, because the lender's willingness to finance a long construction period depends on the guarantee's protection.

The Grain Belt Express case shows both the potential and the fragility of this mechanism. The Loan Programs Office announced a conditional commitment for a loan guarantee of up to 4.9 billion dollars for the first phase of the project in November 2024 (Eenews, 2024). The commitment was conditional on completion of environmental review and other technical, environmental, and financial requirements. The Department terminated the commitment on July 23, 2025, stating that the project did not represent a good financial deal for taxpayers and that it was not critical for the federal government to have a role in the first phase (S&P Global Commodity Insights, 2025; Yahoo News, 2025). The developer announced that it would proceed with private funding.

The termination illustrates a structural weakness. A conditional commitment is not a finished financing, and its value depends on the continuity of the policy under which it was issued. Lenders and developers that planned around the commitment faced the loss of a key financing component after substantial development spending. The episode also shows that federal support can be reversed by a change in administration, which increases the perceived policy risk of all federally supported grid projects. Durable federal finance for transmission therefore requires statutory commitments or other mechanisms that reduce the reversibility of support once it has been offered. The financial effect of a guarantee and its durability are distinct questions. The first depends on the terms of the guarantee, and the second depends on the statute, appropriation, and administrative commitment behind it.

Federal credit transferability

Transferability under section 6418 of the Internal Revenue Code allows an eligible taxpayer to sell certain federal energy tax credits to an unrelated buyer for cash (Public Law 117-169, 2022). The credits eligible for transfer include the clean electricity investment credit and the clean electricity production credit, among others. The Treasury Department and the Internal Revenue Service finalized the transfer regulations on April 30, 2024 (Internal Revenue Service and Department of the Treasury, 2024). Transferability has expanded the market for tax credits by allowing developers that lack tax capacity to monetize credits without entering complex tax-equity partnerships.

For grid finance, transferability addresses the problem only indirectly. Transmission lines are not generally eligible for the clean electricity credits that the Act created, because those credits attach to generation and storage. The benefit to transmission is therefore a consequence of the generation it serves. A generation project that can monetize its credits through transfer becomes more financeable, and the transmission upgrades it requires may be financed with fewer delays. The relationship is real, but it is mediated by the interconnection process and by the timing of generation construction, which means that transferability cannot substitute for a transmission-specific financing mechanism.

Transferability also has a limitation of scale. The market price of transferred credits depends on the demand from buyers, and that demand depends on the buyers' tax

position. A large expansion of transmission financed through credit transfer would require buyers with sufficient tax liability to absorb the credits, and the market's capacity to do so is finite. The mechanism is therefore best understood as a useful supplement to transmission finance, which must be complemented by revenue and cost-recovery mechanisms that are specific to grid assets.

Regulated and hybrid rate-base models

The regulated rate-base model remains the dominant structure for transmission in the United States. Under this model, an approved investment enters the rate base, and the owner recovers its cost of capital through rates charged to customers. The model addresses merchant revenue risk completely, because the revenue is set administratively, and it addresses cost-recovery lag to the extent that regulators allow timely inclusion of investments in rates. Its principal weakness is dependence on regulatory approval and on the cost-allocation decisions that determine which customers pay.

A hybrid model combines regulated or contracted elements with merchant or market-based components. In the transmission context, a hybrid structure might combine a long-term capacity contract with a utility or municipal buyer, which provides contracted revenue for a portion of the line's capacity, with merchant exposure for the remainder. The contracted portion can support senior debt, and the merchant portion can be financed with equity that accepts higher risk in return for higher expected returns. Hybrid structures address merchant revenue risk and cross-jurisdictional allocation at the same time, because the contracts define cost sharing among the buyers.

The hybrid approach has its own limitation. Long-term capacity contracts with creditworthy buyers are scarce for transmission, because the buyers must be willing to commit to payments over decades and must have the credit standing to honor them. Municipal utilities and cooperatives, which have been important buyers in some recent projects, may have limited balance sheets relative to the size of the contracts required. The Grain Belt Express developer reported voluntary transmission service agreements with 39 Missouri municipal utilities, amounting to up to 225 megawatts, but Engineering News-Record's review of the regulatory filings found that those agreements did not include binding long-term revenue commitments (Engineering News-Record, 2025). This distinction between voluntary and binding commitments is central to the financeability of hybrid structures.

Contract design offers a complementary route, and the international record shows how it can be made to work. Beiter, Guillet, Jansen, Wilson and Kitzing (2024) describe contracts for difference as the favored instrument for de-risking large renewable investments, Kroger, Neuhoff and Richstein (2022) show how contracts for difference reduce price risk while expanding deployment, Ason and Dal Poz (2024) document their spread across jurisdictions, and Welisch and Poudineh (2019) analyse auction-based allocation of offshore contracts in the United Kingdom. May, Neuhoff and Richstein (2018) and Onifade (2016) examine the design features that make such contracts effective. A hybrid transmission structure that converted voluntary service agreements into contracts-for-difference-style binding commitments would address the scarcity identified here, though no U.S. jurisdiction yet provides that framework.

Portfolio-level financing

Portfolio-level financing aggregates many assets into a single financing vehicle, which diversifies risk across assets and allows investors to finance projects that would be too small or too risky individually. The approach is familiar in renewable energy project finance, where developers pool distributed or utility-scale projects to achieve scale (Steffen, 2018). Its application to grid assets is less developed, because transmission projects are typically large, unique, and lumpy, which makes them difficult to combine in standard portfolios.

Portfolio financing can nonetheless address construction risk and sponsor capacity. A portfolio of smaller grid projects, such as distribution upgrades, substation expansions, and reconductoring of existing lines, can be financed through a programmatic approach in which standardized designs, contractors, and performance metrics reduce the uncertainty of each project. The diversification across projects reduces the impact of any single overrun. The requirement is standardization, which is costly to achieve for transmission because each line depends on its route, its terrain, and its interconnection points.

The limitation of portfolio financing lies in correlated exposure. Grid projects in the same region share regulatory, environmental, and market risks, so a portfolio concentrated in one region may be exposed to the same shock across all its assets. The diversification benefit is therefore less than the number of assets suggests. Investors must assess the correlation of risks across the portfolio, and they must be satisfied that performance is transparent enough to monitor. Without these conditions, portfolio structures reproduce the risks of their components rather than reducing them.

Infrastructure investment funds and institutional investors, including pension funds and insurance companies, represent a potentially large source of long-duration capital for grid assets, because their liabilities match the long horizons of transmission investment. Their participation depends on the availability of assets with stable, contracted, or regulated cash flows and on confidence that those cash flows will persist. Regulated rate-base assets can meet those requirements where cost recovery is timely, which is one reason why regulated utilities have historically financed most transmission through balance-sheet capital and why infrastructure investors have acquired stakes in regulated utility assets. Merchant lines, by contrast, rarely meet the stability criteria that long-duration investors apply. A

portfolio vehicle that combines regulated and contracted grid assets can therefore offer institutional capital a route into transmission finance, provided that the vehicle is transparent about the regulatory and contractual terms underlying each asset.

Tax-exempt capital provides a further option that is distinct from the structures above. Public power entities and cooperatives can generally borrow at tax-exempt rates, which lowers their cost of debt relative to investor-owned utilities and independent developers. Their participation in transmission finance is particularly important for interregional lines that serve multiple municipal and cooperative buyers, because those buyers can contribute both contracted revenue and low-cost borrowing capacity. The limitation is that tax-exempt financing is restricted to qualifying public entities, and that federal limits on private use of tax-exempt-financed property constrain how such capital can be combined with private equity in a single project. Ownership and revenue arrangements that mix public and private participants must therefore be designed with those restrictions in view, which adds legal complexity and lengthens the structuring period.

Portfolio approaches are better developed on the generation side, and their record there is instructive. Schwabe, Cory and Newcomb (2009) document the effects of the financial crisis and federal legislation on renewable project financing, Feldman, Bolinger and Schwabe (2020) estimate project-finance costs across technologies, and Mormann (2014) analyses how tax-equity reliance raises financing charges and limits liquidity. Bolinger (2014) and Fink (2014) examine alternatives that widen access to capital markets. On the aggregation mechanics, Lowder and Mendelsohn (2013), Alafita and Pearce (2014), and Mendelsohn, Urdanick and Joshi (2015) analyse securitization and credit enhancement for solar portfolios, showing both the cost reductions available from pooling and the rating and transparency requirements that pooling imposes. These requirements are precisely the ones that the standardization constraint identified above makes difficult for transmission.

Debt service and the cost of financing

The choice among capital structures affects the financing cost of a project, and the effect can be quantified. For a project financed with a single fixed-rate loan repaid in equal annual installments, the annual debt service is given by

$$P_{annual} = P \times \frac{r}{1-(1+r)^{-n}}$$

where P is the principal, r is the annual interest rate, and n is the number of years to maturity. The formula describes a level-payment annuity, which is a common structure for long-dated infrastructure debt.

Financing conditions for capital-intensive energy technologies are sensitive to prevailing interest rates, because the share of upfront cost in lifetime cost is large (Egli, Steffen and Schmidt, 2018; Schmidt et al., 2019). The cost of capital is also the main source of cross-country and cross-technology variation in project economics (Steffen, 2020), and project finance is the structure through which sponsors isolate project risk from their own balance sheets (Steffen, 2018). The weighted average cost of capital for a project financed with both debt and equity can be written as

$$WACC = \frac{E}{V} R_e + \frac{D}{V} R_d \left(1 - T_c\right)$$

where E is the equity, D is the debt, $V = E + D$, R_e is the required return on equity, R_d is the interest rate on debt, and T_c is the corporate tax rate. The expression shows that a reduction in the cost of debt, whether from a guarantee, a contracted revenue stream, or a more favorable tax position, lowers the cost of capital in proportion to the debt share of the capital structure.

Table 3 applies the annuity formula to a hypothetical 1-billion-dollar grid project financed with a 30-year level-payment loan at three interest rates. The rates are chosen to represent a guaranteed or highly contracted structure at 5 percent, a moderately contracted structure at 6 percent, and a merchant-exposed structure at 7 percent. They are illustrative and are not drawn from any specific transaction. The calculation shows how sensitive debt service is to the interest rate. It does not establish which capital structure would produce each rate.

The calculation shows that a two-percentage-point increase in the interest rate raises annual debt service by about 15.5 million dollars on a 1-billion-dollar loan, and raises total payments over the loan's life by roughly 466 million dollars. For a project of this size, the difference between a guaranteed structure and a merchant-exposed structure is therefore a financing burden of roughly 15 million dollars each year. That magnitude explains why the choice of structure, and the credibility of the guarantee or contract that supports it, matters so much for the financeability of grid projects.

Capital-structure theory supplies the vocabulary for the debt-service constraints discussed above. Modigliani and Miller (1958) show that, under idealized assumptions, financing structure does not change firm value, and Modigliani and Miller (1963) add the tax deductibility of interest, which favors debt. Myers (1984) reviews the trade-off and pecking-order accounts of financing choice, and Myers and Majluf (1984) show that information asymmetry can lead firms to forgo investment rather than issue equity. Jensen and Meckling (1976) develop the agency costs of debt and outside equity, and Harris and Raviv (1991) survey models based on agency costs and asymmetric information. Graham and Harvey (2001) survey 392 chief financial officers

Table 3: Annual debt service on a hypothetical 1-billion-dollar grid project financed with a 30-year level-payment loan (differences computed before rounding)

Interest rate (percent)	*Annual debt service (million dollars)*	*Total payments over 30 years (million dollars)*	*Difference in annual debt service relative to 5 percent (million dollars)*
5	65.1	1,951.5	0.0
6	72.6	2,179.5	7.6
7	80.6	2,417.6	15.5

and find partial support for the pecking-order and trade-off hypotheses.

Assessment of the toolkit

The four structures have complementary strengths, and the value of policy-backed finance depends on the macroeconomic conditions in which it is deployed (Schmidt et al., 2019). Federal loan guarantees and regulated rate-base models address cost-recovery lag and merchant risk most directly, but they depend on policy and regulatory decisions that can change. Transferability is durable in statute but addresses grid finance only indirectly through generation. Hybrid structures respond to cross-jurisdictional allocation and merchant risk, but they require long-term contracts that are scarce. Portfolio financing addresses construction risk and sponsor capacity, but its benefits depend on standardization that transmission does not easily allow.

The toolkit therefore leaves three gaps. The first is a durable federal mechanism for transmission that does not depend on generation and that is not reversible once offered. The second is a contracting framework that allows interregional beneficiaries to commit to long-term payments in a binding form. The third is a method for allocating construction overrun risk across sponsors, regulators, and customers in a manner that protects investors without transferring excessive cost to ratepayers. These gaps are not technical. They are institutional, and they require coordinated action by federal agencies, regulators, and legislatures.

Discussion

Implications for policymakers

The analysis suggests that policymakers should begin by identifying the binding barrier for a given class of grid investment, and should then design the instrument that addresses it. Where the binding barrier is cost-recovery lag, the appropriate response is regulatory reform that allows timely inclusion of investments in rates, with mechanisms that reduce the cost of capital during construction. Where the binding barrier is merchant revenue risk, the response is contracting frameworks that convert merchant exposure into binding long-term commitments from beneficiaries. Where the binding barrier is cross-jurisdictional allocation, the response is interstate cost-sharing agreements, which require negotiation among states and utilities but which can be supported by federal planning studies.

Federal support deserves particular attention. The termination of the Grain Belt Express commitment illustrates that a conditional guarantee cannot be treated as a durable input to project finance. Policymakers who wish to rely on federal financing for grid projects should consider statutory frameworks that reduce reversibility, such as multi-year appropriations with defined eligibility criteria, or insurance-style mechanisms that cannot be withdrawn after project commitments have been made. The question is not whether federal support is desirable, but whether it is credible enough for developers and lenders to build on.

The fragility of federal support has an analogue in the transition-risk literature. Curtin et al. (2019) and Semieniuk et al. (2022) document how changes in expected policy repriced carbon-intensive assets, and the same mechanism operates in reverse for projects built on expected federal support: when the support is withdrawn, the projects' financing terms and sometimes their viability change. Liu (2025) and Bennon and Wilson (2023) document how litigation and permitting risk compound this exposure by lengthening the period during which support must remain in place.

Policymakers should also recognize that transferability and interconnection reform affect grid finance indirectly but significantly. Transferability makes generation more financeable, and the Order No. 2023 cluster process aims to make interconnection timing more predictable. Both are useful. Neither substitutes for a transmission-specific framework that addresses the barriers identified in Section 3.

The policy response can also be sequenced. The analysis in Section 3.7 suggests an order in which the barriers bind during development, and reforms can follow that order. The first step is to resolve the contracting and allocation barriers, because they determine whether any financing structure can be built at all. Without binding long-term commitments from beneficiaries and an agreed allocation of cost among states, neither a federal guarantee nor a regulated rate base can support a project of interregional scale. The second step is to align interconnection timing with transmission planning, so that network upgrades are scheduled to match the generation they enable. The Order No. 2023 reforms address this step directly, although their effect depends on implementation by individual transmission providers (Federal Energy Regulatory Commission, 2023; Federal Energy

Regulatory Commission, 2024b). The third step is to design construction-risk protections, including overrun allocation and contractor incentives, that give investors confidence to commit capital once the earlier barriers have been resolved.

Regional prioritization can concentrate effort where the need is greatest. The Needs Study identified the Midwest, the Great Plains, and Texas as priority regions for new transmission (Perkins Coie, 2023; U.S. Department of Energy, 2023). A regional sequence that begins with contracting and allocation agreements in those regions, followed by interconnection alignment and construction protections, would match public effort to the places where transmission constraints are most severe. Such a sequence would not eliminate the need for national frameworks, but it would give policymakers a means of testing reforms in the settings where the barriers are most acute.

Demand growth is changing the planning baseline. The IEA's Electricity 2025 report forecasts global electricity consumption growing at close to 4 percent a year through 2027 (International Energy Agency, 2025).

Implications for developers

Developers of grid projects should assess their projects against the five barrier categories at an early stage, and should plan financing structures that address the binding barrier. A project whose principal barrier is merchant revenue risk should prioritize contracts with binding long-term commitments, even if these reduce the project's expected upside. A project whose principal barrier is construction risk should prioritize contractors and equipment suppliers that offer credible overrun protection, and should negotiate allocation of overrun risk with regulators and customers in advance. A project that depends on federal support should maintain a financing plan that does not rely on the support, so that a change in policy does not cause the project to fail.

The Grain Belt Express experience suggests that developers should also treat voluntary agreements with buyers as provisional (Engineering News-Record, 2025) until they are converted into binding commitments. Voluntary agreements can establish interest and demonstrate demand, but lenders require commitments that can be enforced. Developers that secure binding agreements early improve their financing position and reduce the risk of restructuring after development spending has been committed.

Implications for investors and lenders

Investors and lenders should evaluate grid projects with attention to the reversibility of their support and the binding nature of their revenues, since lenders size project debt against revenues they can enforce (Steffen, 2018). A conditional federal commitment should be valued at its probability of continuity rather than at its face amount. A revenue stream from voluntary agreements should be discounted relative to one from binding contracts. The debt-service arithmetic in Table 3 shows that the difference between these assessments is material for projects of this size.

Investors should also consider the correlation of risks across a portfolio of grid assets. Regional concentration in transmission investment exposes portfolios to common regulatory, environmental, and market shocks, and diversification benefits should be measured accordingly. Standardization of project designs, transparent reporting of construction and operating performance, and clear documentation of cost-allocation arrangements all improve the ability of investors to assess correlated risks.

A further implication concerns disclosure. Financing terms for grid projects are rarely published, which makes it difficult for analysts to compare structures or to calibrate the risk premia that lenders apply. The empirical literature on renewable energy finance shows how valuable compiled financing data can be. Data sets assembled from individual transactions revealed the strong improvement in renewable financing conditions and the role of macroeconomic conditions in driving that improvement (Egli, Steffen and Schmidt, 2018). Equivalent data for grid assets would allow investors to observe how structures perform across regions and across economic cycles. Public announcements of federal loan decisions report headline amounts, but the terms that determine a project's cost are generally not reported in a standard form. Public agencies that collect information on interconnection, cost recovery, and loan guarantees could contribute by publishing aggregated terms, provided that the confidentiality of individual transactions is protected. Greater transparency of this kind would reduce the information asymmetry that currently forces investors to rely on the public statements of the sponsors and agencies involved.

Offshore wind financing research illustrates what such transparency would enable. Hansen, Wilson, Fitts, Jansen et al. (2024) identify five grand challenges of offshore wind financing in the United States, drawing on documented transaction and policy experience; Dukan, Gumber, Egli and Steffen (2023) quantify the effect of policy design on the offshore cost of capital in Europe; and Levitt et al. (2011) provide the long-run cost benchmark against which U.S. projects are judged. Feo and Ludmir (2009) document the development and financing challenges specific to U.S. offshore projects. Each of these studies depended on financing terms or procurement results being public, which is the condition that grid finance generally fails to meet.

Limitations

The analysis has several limitations. The classification of barriers is analytical rather than statistical, and the evidence presented for each barrier is illustrative rather than exhaustive. The capital structure assessment is qualitative in part, because the terms of most grid financings are confidential, and the illustrative calculation in Table 3 uses hypothetical rates that do not represent any transaction. The Vogtle expansion (Associated Press-Atlanta Journal-Constitution, 2024) is a nuclear project rather than a transmission project, and its lessons apply to grid finance by analogy. The Grain Belt

Express case is recent, and its outcome remains uncertain because the developer continues to pursue the project with private funding.

The nuclear finance literature sharpens the analogy. Spangler, Qin, Larsen et al. (2025) analyse the recent AP1000 experience and the financing risks that remain for subsequent builds; Forsyth, Larsen, Spangler, Bolisetti et al. (2026) analyse stakeholder involvement in nuclear cost overruns and the contract structures that allocate them; and Spangler, Hansen, Gevondyan and Kim (2024) quantify the investment risk of the Vogtle purchase decision itself. These studies show that the allocation of overrun risk documented in Section 3.5 is measurable, which means the third toolkit gap identified in Section 4.7 can be addressed with instruments whose effects can be estimated before they are adopted.

These limitations point to directions for further research. The most valuable would be systematic collection of financing terms for transmission projects, which would allow the barrier classification and capital structure assessment to be tested against observed outcomes. Comparative work on how other countries have structured grid finance, including the use of regulated asset bases, state-owned transmission companies, and competitive tenders, would clarify which features of the U.S. toolkit are specific to its institutions and which are general.

Prior validation efforts in adjacent fields provide the template. Egli, Steffen and Schmidt (2018) assembled transaction-level financing data that revealed the dynamics of financing conditions, and Steffen et al. (2025) extended that effort into a global dataset of the cost of capital for renewable projects. In the microgrid literature, Williams, Jaramillo and Taneja (2018) validated a stochastic techno-economic model against documented utility performance in Rwanda, and Kumar et al. (2022) demonstrated a multi-dimension design framework that could be scored and compared. The readiness framework could be validated in the same way if development-stage data on contracts, permits, and interconnection status were collected systematically.

Financing the expansion of the U.S. electricity grid is constrained by institutional arrangements as much as by the cost of capital. This paper asked which barriers impede grid investment and which capital structures respond to them. It identifies five barrier categories, each of which affects financing in a distinct way: cost-recovery lag, merchant revenue risk, interconnection timing, construction risk, and cross-jurisdictional allocation. The current toolkit of federal credit transferability, federal loan guarantees, regulated and hybrid rate-base models, and portfolio financing addresses parts of this problem, but it leaves three gaps: a durable federal mechanism for transmission that does not depend on generation and cannot be withdrawn once offered, a binding framework for interregional contracting, and a method for allocating construction overrun risk between investors and customers.

The paper contributes a classification that links each barrier to a specific financing consequence, an assessment of capital structures against the barrier each is designed to address, and an explicit calculation showing how financing costs translate into annual burdens. That calculation shows that a two-percentage-point difference in interest rate on a large project amounts to roughly 15 million dollars a year, which makes the credibility of guarantees and contracts central to financeability. Closing the gaps requires coordinated action by federal agencies, regulators, and legislatures, and capital structures designed around the multi-decade life of grid assets rather than the shorter horizons of generation and storage projects.

The conclusions carry limitations. The barrier classification is analytical rather than statistical, and the evidence for each barrier is illustrative rather than exhaustive. The terms of most grid financings are confidential, so the capital structure assessment is partly qualitative. The debt-service calculation uses hypothetical rates, and the Vogtle expansion is a nuclear project whose lessons apply to transmission by analogy. The outcome of the Grain Belt Express project also remains uncertain.

Future research should test the classification against transaction-level data on grid financings, which would require public disclosure of financing terms. It should also compare capital structures empirically across regions and economic cycles, and examine how the reversibility of federal support affects the cost of capital that lenders and developers require.

Financing the expansion of the U.S. electricity grid is constrained by institutional arrangements as much as by the cost of capital. Cost-recovery lag, merchant revenue risk, interconnection timing, construction risk, and cross-jurisdictional allocation each impede investment in distinct ways, and each calls for a different response. The current toolkit of federal credit transferability, federal loan guarantees, regulated and hybrid rate-base models, and portfolio financing addresses parts of the problem, but it leaves gaps in durable federal support for transmission, in binding interregional contracting, and in the allocation of construction overrun risk. Closing those gaps requires coordinated action by federal agencies, regulators, and legislatures, and it requires capital structures designed around the multi-decade life of grid assets rather than around the shorter horizons of generation and storage projects.

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