Decision-Making in PJM's Interconnection Process
An Agent-Based Modeling Approach to ERIS Adoption

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Summary

PJM Interconnection, the largest regional transmission organization in the United States, is facing mounting pressure to accelerate the interconnection of new energy generation resources to meet load while maintaining system reliability and minimizing rate payer impacts. The interconnection process- the procedure through which new generation projects get connected to the existing transmission grid is a key bottleneck in the clean energy transition. Over the past decade the queue of projects waiting to get interconnected in PJM has grown to greater than the total installed capacity in PJM. Each year the average time in queue has increased, as have the costs assigned to projects for network upgrades required to connect them to the grid. Meanwhile, while the MW of new generation resources coming online has decreased each year, load continues to increase and the grid is becoming capacity constrained, one symptom of which is the capacity market clearing with record small margins the last two years. In the face of large and increasing queue sizes and wait times, interconnection reforms are receiving increased attention from policy makers, advocates, and academics. One such reform is wider adoption of Energy Resource Interconnection Service (ERIS) agreements.

Energy Resource Interconnection Service (ERIS) in theory provides a less expensive and speedier alternative to the incumbent Network Resource Interconnection Service (NRIS) agreements. Under ERIS agreements, projects theoretically are assigned fewer network upgrade costs and receiver speedier study treatment in exchange for forgoing capacity accreditation, and the related payments. There exists a balance of NRIS and ERIS agreements at a system level that both accelerates the connection of new resources and provides sufficient reliability in the capacity market. However, in PJM, near zero percent of the queue applicants select ERIS. This outcome reflects the fundamental mismatch of PJM's process signals and developer incentives with overall system benefits. It is critical to understand the factors that shape a developer's decision making process and what institutional and structural reforms are required to align ERIS adoption with project developer interests. This research proposal address this challenge by asking:
How can PJM's interconnection process be redesigned to better align developer incentives with ERIS adoption?

To explore the gap between desired system outcomes and the developer adoption of ERIS necessary to get there, this thesis develops a conceptual agent based model that simulates project developers' service type decisions under different reform strategies. The model examines how allocation of network upgrade project costs and study times in combination with market revenues, and transmission constraints affect ERIS adoption and system outcomes under a simulation of real world constraints. The model treats ERIS adoption as a dynamic outcome of expectation-driven behavior. Developers make adoption decisions based on perceived revenues and costs from the capacity and energy market, risk of network upgrades, cost assignment, and the decisions of other developers. Meanwhile PJM conducts interconnection study batches to determine required network upgrades and allocates costs to developer project clusters. The model explores three interconnection scenarios based on analysis of PJM's governance and interconnection process, and those of other U.S. RTOs: (1) undifferentiated in which is ERIS is studied in same manner as NRIS, (2) distinct where ERIS is assigned minimal NU and studied separately, and (3) distinct under high transmission planning, where in addition to ERIS distinction, heavy investment is made in transmission outside of the Interconnection process. These strategies are evaluated by the amount of generation brought online each year, changes to a metric developed for a congestion proxy, and capacity market prices, and impacts on system energy costs and percent of load met by renewables. The simulation results show that meaningful differentiation of ERIS from NRIS projects and transmission planning can significantly accelerate the integration of resources from all service types onto the grid, reduce interzone congestion, and bring down capacity prices.

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Abbreviations

Abbreviation	Definition
ABM	Agent Based Model
AEP	American Electric Power
ATT	Advanced Transmission Technology
BRA	Base Residual Auction
COMED	Commonwealth Edison Company
DOM	Dominion Energy
DOE	Department of Energy
ERIS	Energy Resource Interconnection Service
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GETS	Grid Enhancing Technology
GW	Gigawatt
IAD	Institutional Analysis and Development
LMP	Locational Marginal Pricing
MEC	Mid American Energy Company
MW	Megawatt
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
NRIS	Network Resource Interconnection Service
PPA	Power Purchase Agreement
RPM	Reliability Pricing Model (PJM)
RTO	Regional Transmission Organization
TO	Transmission Owner

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Chapter 1. Introduction

The introductory chapter presents the topic background and explicates the problem (Section 1.1) It then identifies the knowledge gap and formulates the research questions (Section 1.2), along with the chosen research approach (Section 1.3) and its relevance to the CoSEM program (Section 1.4). Finally, it concludes with an outline of the report (Section 1.5).

1.1 Background

A key bottleneck in the clean energy transition is the procedure through which new generation projects get connected to the existing transmission grid, called the interconnection process. In the Northeast of the United States, PJM is the Regional Transmission Organization (RTO) responsible for administering the connection of new generating facilities across thirteen states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia for 60 million customers. PJM is an unbundled market in which generation owners are separate from transmission owners. PJM RTO's service territory is divided across twenty-one transmission owner regions (Figure 1)(PJM, 2024).

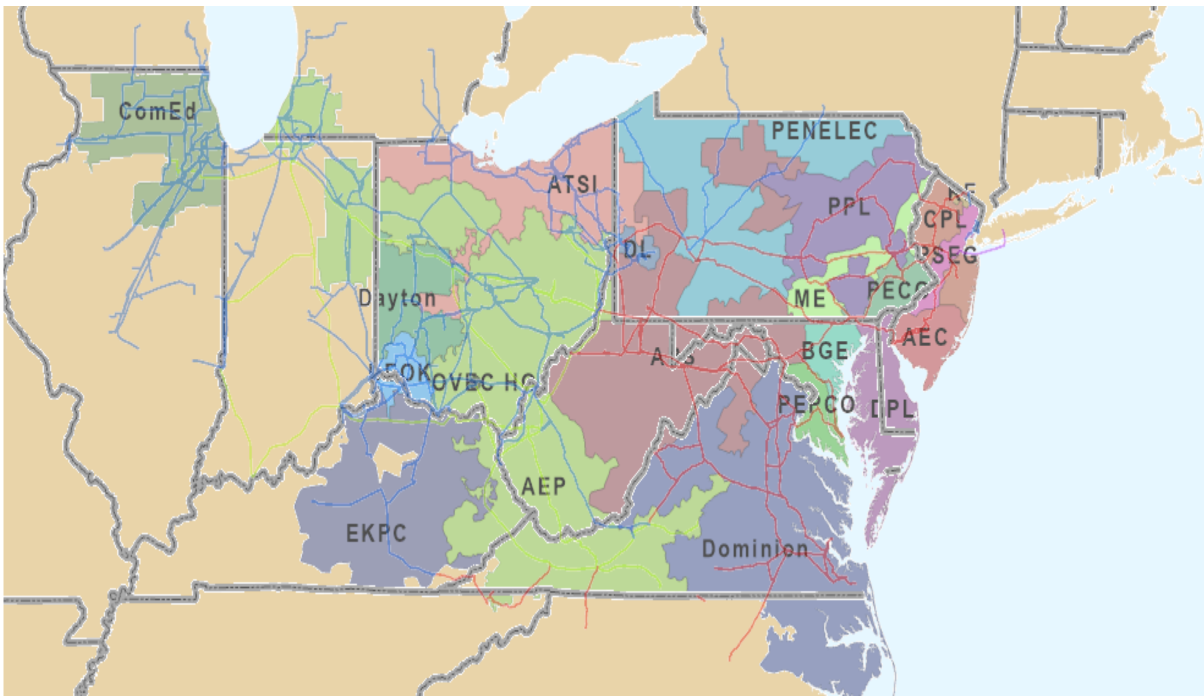


Figure 1: PJM Service Territory, Transmission, Transmission Owner Zones and Transmission Lines >= 230kV (PJM System Map, 2025)

PJM RTO conducts phased technical studies of a proposed generation project's impact on the grid and assigns the project developer the costs to interconnect it while meeting reliability standards. Sixty GW of projects are currently in PJM's interconnection queue, and forty GW of projects have gone through the queue but have not yet been constructed (PJM Interconnection Reform, 2025). Together, these unconnected generation projects add more than half of the approximately 198 GW of capacity currently installed on PJM's grid (Market Monitoring Report, 2024 p73.) An overwhelming majority of queued projects are battery and solar. The duration from interconnection requests to interconnection agreements in PJM has increased as have the costs assigned to projects for network upgrades (LBNL, 2024 p.35) (PJM Serial Service, 2025).In the face of large and increasing queue sizes and wait times, solutions have been identified and advocated for in interconnection queue reform. One such reform is encouraging wider adoption of Energy Resource Interconnection Service (ERIS) agreements instead of Network Resource Interconnection Service (NRIS). (U.S. DOE, 2024)

In the PJM system, when a developer applies to connect a new generation project to the grid, they select either ERIS or NRIS service. ERIS allows generators to be connected using "as available" transmission without requiring the same level of deliverability as NRIS. Whereas NRIS allows the generators to be deliverable during congested grid conditions, such that the generator can be designated as a capacity resource. Both service types participate in the wholesale energy market, but only NRIS resources can participate in the capacity market. The selection has advantages and disadvantages at the project and system level. The basic argument for encouraging use of *as available* transmission is that building a system capable of delivering all generation under all conditions would be prohibitively expensive. In theory for developers, ERIS has three advantages over NRIS (1) reduced network upgrade costs, by avoiding upgrades needed for deliverability;(2) faster processing timelines, due to simpler study assumptions and less dependency on upgrades; and (3) faster connection timelines, by allowing connection to the transmission system before network upgrades are completed. From the PJM system perspective, the benefits of ERIS adoption are to (1) relieve interconnection bottlenecks and expedite processing times and (2) to improve the efficient utilization of the transmission system as variable renewable generation and battery storage become a larger share of generation mixes.

Table 1: Conceptual Advantages and Disadvantages of ERIS and NRIS Service

Service Type	Definition	System Benefits and *Disadvantages*	Developer Impacts
ERIS	Offered as available	Fewer network upgrades Quicker to study Relieves interconnection back-log Higher utilization of transmission Lower barrier to entry/higher competition	Less time in interconnection queue Less network upgrade costs Faster connection timelines
		No reliability contributions *Freerides on other project's buildout*	*No capacity market payments*
NRIS	Must be always available Cannot be curtailed	Contributes to reliability Pays for Grid Buildout	Eligible for capacity market payments
		Requires significant network upgrades Intensive study process *Contributes to interconnection back-log*	*Costly and time intensive*

At the system level, there is a level of ERIS penetration on the grid above which there would not be enough generation capacity resources to clear the capacity market, and the capacity market would fail. This is a function of how PJM has chosen to ensure resource adequacy. For instance, RTOs such as The Electric Reliability Council of Texas (ERCOT) function as an energy-only market without a capacity market and use scarcity pricing during tight supply conditions (Siddiqi, 2007). There is also a level of ERIS penetration that is below optimal, as it is now, as represented by a large and growing back-log of queued projects, many of which are dropping out with high assigned network upgrade costs.

In PJM less than one percent of projects request ERIS agreements. The drivers of this misalignment between the significant potential benefits of ERIS agreements to both PJM and developers, and the extremely limited uptake is not fully understood and has significant consequences on system outcomes. Queue backlogs delay the deployment of clean energy resources needed to reliably meet load growth and clean energy goals. High assigned network upgrade costs mean many projects drop out of the queue process before receiving interconnection agreements, reducing the number of projects that come online each year. Resultant high-capacity market clearing prices increase electric ratepayer affordability. Without reforms that realign developer incentives with the benefits of ERIS adoption, PJM risks a protracted and inefficient interconnection process characterized by outcomes of capacity scarcity and increasing electricity bills. Therefore, it is critical to understand the developer decision-making processes in selection of service type and through this understanding of processes and institutions, design target reforms.

1.2 Knowledge Gap and Research Questions

Policy reports and academic analyses have explored the benefits of ERIS agreements for the system as a whole and what factors generation project developers consider in their general decision making. However, there is a lack of understanding of the interaction between developer incentives and PJM system dynamics that result in very low ERIS adoption. Little is understood regarding how reforms could be implemented to encourage wider ERIS adoption to contribute to an improved interconnection queue process at the system level.

The following main research question is designed to address this identified knowledge gap:

What reforms in PJM solve the misalignment between generation project developer incentives and the need for greater PJM system-level ERIS adoption to improve the interconnection process?

Next, subquestions were developed to parse out the analysis required to answer the main question. First, the identification of factors is required.

Subquestion 1: *What factors shape how developers choose between ERIS and NRIS agreements in PJM?*
This subquestion is addressed in Chapter 3 “Developer Decision Factors and Incentives” and Chapter 4 “ABM Design via Institutional Analysis Application” and

Next, the response dynamics and interactions of the developers with each other and system conditions needs to be understood.

Subquestion 2: *How do developers respond to policy signals, peer behavior, and system constraints when selecting ERIS or NRIS agreements?*

This subquestion is addressed through Chapter 5 “Experimental Design” and Chapter 7 “ABM Experimentation and Analysis”

Finally, the design and evaluation of potential reforms for desired outcomes is conducted.

Subquestion 3: *How could targeted reforms shift developer behavior and improve interconnection outcomes in PJM?*

This subquestion is addressed in Chapter 5 “Experimental Design” and Chapter 8 “Reform Scenario Results”.

1.3 Research Approach

The research utilizes two primary and complementary approaches of Institutional Analysis and Agent Base Modeling (ABM).

Institutional analysis is conducted via desk research on the institutional, governance, economic, procedural, and technological dimensions that inform or constrain interconnection choices. To achieve this, an Institutional Analysis and Development (IAD) framework is applied to PJM’s interconnection procedures, with particular attention to the decision points, evaluation criteria, timelines, and outcomes that distinguish the ERIS and NRIS tracks using PJM manuals, tariff language, stakeholder meeting notes, whitepapers and conversations from stakeholders and advocates in the PJM space to construct a detailed understanding of how the interconnection process operates in practice, including informal norms or bottlenecks. In addition to analyzing institutional structures and procedures, this research investigates the underlying incentives that drive developer decision-making when choosing between ERIS and NRIS agreements to explore how developers weigh cost, schedule, risk tolerance, offtake strategy, and future capacity value in their interconnection decisions. The objective is to contextualize the interconnection process within the broader business and strategic frameworks in which developers operate. By pairing institutional analysis with an exploration of developer incentives, this section aims to develop a holistic understanding of the forces shaping interconnection service selection in PJM.
The results of the institutional analysis are then incorporated into the development of an agent-based model (ABM). ABM is a methodology to study complex socio-technical systems by analyzing the interactions between individual behavior and decision making that lead to broader system impacts. In ABM, heterogeneous actors have unique states and interact with other agents and the environment under specific rules. Thus, the impact of mechanisms and conditions on the behavior of a system and the actors can be studied. The model is developed in Python using the Mesa library, which is well-suited for replicable, modular simulations of heterogeneous agents over time (Mesa, 2025). The modeling is a quantitative research methodology as real-world data sources are incorporated and matched to identified institutional factors and interactions. Agent behavior is structured around a decision-making process where each developer, upon entering the interconnection queue, evaluates the observed behavior of neighbors and non-neighbors, policies, and system conditions. The environment is populated with factors and interactions identified in the Institutional Analysis. Model outputs are those which answer the primary research question and include the percentage of agents selecting ERIS versus NRIS under each scenario and characteristics of those agents choosing either option, and changes over time. Results are tested against actual ERIS adoption in the current status quo PJM environment. A sensitivity analysis is run on the model to determine which factors are particularly compelling the overall adoption and rate of adoption of ERIS agreements.

Three reform scenarios are developed from the PJM institutional analysis and a literature review of academic and government proposals. The scenarios reflect different combinations of institutional, technical, and economic changes. Each scenario is simulated to assess its impact on ERIS adoption and the system at large.

1.4 CoSEM Relevance

This research is highly CoSEM relevant, as it combines technical energy system understanding with decision-making dynamics and market design in a complex setting with significant path dependence. The current interconnection process for new generation facilities poses governance challenges in a multi-actor setting. Coordination issues arise when managing the connection of new generation across various jurisdictions and grid regions, potentially slowing down the integration of renewable energy and increasing costs for consumers. The research focuses on applying CoSEM principles, such as multi-actor decision-making, institutional design, and market analysis, to propose solutions that streamline the interconnection process and improve system performance. The goal of the research is not only to understand the existing dynamics but also to design a system intervention that improves the efficiency, fairness, and reliability of generation interconnection processes, both of which are critical for achieving a rapid and just clean energy transition by applying CoSEM curriculum and concepts.

1.5 Outline of Report

This thesis begins in Chapter 2 by establishing the theoretical framing for the research in terms of the theory of different interconnection service types, transmission planning as a chicken and egg problem, generation interconnection as a governance coordination challenge, and institutional analysis as a relevant framework for the research. Chapter 3 identifies and analyzes developer incentives. Chapter 4 applies the IAD framework to the PJM generation interconnection process and applies it to the development of the ABM. Chapter 5 sets up the experimental design of ABM. Chapter 6 delivers the software implementation. Chapter 7 presents an analysis of the model experimentation for the baseline scenario. Chapter 8 implements the reform scenarios. Finally, Chapter 9 offers a broader reflection on the theoretical and policy implications of the results and identifies directions for future research.

Chapter 2. Theoretical Background

Building from the introduction's framing of the problem, this chapter introduces three critical concepts to understanding the developer decision making dynamics in PJM. The first section details the theoretical underpinnings of ERIS as an interconnection reform and differences between theory and application. The second provides framing for generation interconnection as a governance coordination problem to understand what has led to the current state of the grid in PJM. The third section details how transmission planning as a chicken and egg dilemma interacts with generation interconnection.

2.1 Energy Resource Interconnection Service as a Queue Reform

Per the United States Federal Energy Regulatory Commission (FERC) regulations, transmission providers are required to offer at least two interconnection services to FERC jurisdictional interconnection customers: NRIS and ERIS (FERC, 2023). Interest in using ERIS agreements as a means to "fix" interconnection queues has intensified in recent years. In April 2024, The U.S. Department of Energy (DOE) released the agency's first Transmission Interconnection Roadmap, including the following solutions related to flexible interconnection service:

- "Create new and better use existing fast-track options for interconnection, such as….energy-only interconnection service" (Solution 2.5)
- "Ensure that generators have the option to elect energy-only interconnection and be re-dispatched rather than paying for network upgrades." (Solution 3.2)

(DOE I2X, 2024)).

Additionally, in August 2025, PJM stakeholders passed an issue charge, asking PJM RTO to consider adding "additional language that will allow for the additional possibility for energy-only operation under certain conditions prior to the required network upgrades for the new interconnection generation is completed" (PJM Issue Charge, 2025)

Interest in ERIS agreements as a reform option has grown in part due to the interconnection successes. ERCOT operates as an energy-only market without a capacity market, meaning all generators connect as energy-only resources (Du, 2023). This approach has allowed projects to interconnect more quickly with fewer network upgrades. Between 2021 and 2023, ERCOT interconnected nearly twice as much capacity as PJM despite serving only half of PJM's peak load, and its average interconnection processing time is roughly half that of markets such as PJM and New York Independent System Operator (NYISO) (LBNL, 2024) ERIS agreements provide solutions to the large barriers to bringing new generation online in today's interconnection landscape. Interconnection studies assign increasingly expensive network upgrades, causing many projects to drop out of the queue. These network upgrades are time and material intensive, lengthening construction time and delaying projects even after they have received generation interconnection agreements (GIAs). ERIS agreements, in theory, require fewer network upgrades and thus should be assigned less cost and any connective infrastructure should be constructable quickly. One study conducted a power flow simulation to re-simulate a Duke Energy Progress recent resource solicitation cluster study as ERIS instead of NRIS agreements. The study found that switching from NRIS to ERIS agreements for the selected utility-scale solar cluster results in a 72% reduction in network upgrade costs related to thermal power flow overloads, 75% reduction in identified overloads, and reduction of capacity-weighted costs by $112 per kilowatt (kW) of studied solar generation capacity (Norris, 2024) Pre-Workshop Comments and Exhibit of Tyler H. Norris of Duke University). Another analysis of comparative network upgrade costs for NRIS versus ERIS based on Lawrence Berkeley National Laboratory data found that on average, ERIS requests are assigned fewer costs than NRIS requests, driven by the higher prevalence of ERIS requests assigned zero costs but not universally. There is a growing prevalence of ERIS studies resulting in allocated network upgrades (Norris and Watts, 2024).

Furthermore, ERIS agreements could result in less time-consuming NRIS studies if, for instance, their impact was separated from NRIS in the cluster study process, and thus the size and complexity of the NRIS clusters would decreases. Assuming a finite study resource allocation and finite supply chain, ERIS agreements could leave efforts and material resources for NRIS projects. A current issue is that projects drop out of the study process and result in restudies. Siloing ERIS agreements from NRIS study clusters would result in potentially less restudy, saving time and money, presuming that resources can not switch resource request types once applications are submitted (Norris and Watts, 2024).

2.2 Transmission Planning and Generation Interconnection

The state of transmission today in PJM is the result of PJM's transmission planning being largely piecemeal, reactive, and insufficiently regional, allowing for limited headroom and transmission capacity for new generation. The generation interconnection process has effectively become the primary mechanism for network upgrades, placing an inefficient and fragmented economic burden on developers. This inefficiency is due to the fact that transmission and generation interconnection face a classic chicken-and-egg dilemma: new transmission depends on generation development, while new generation depends on available transmission capacity. Texas addressed this challenge in 2008 with a major grid expansion that connected West Texas wind resources to eastern demand centers (Lasher 2008). While large-scale grid expansion projects are costly and time-intensive undertakings (Davis, Hausman, and Rose 2023), the benefits of transmission investments include the reduction of wholesale electricity prices (LaRiviere and Lyu 2022), congestion reduction (Fell, Kaffine, and Novan 2021), limits to fossil fuel market power (Doshi 2024), and encourages anticipatory renewable investment (Gonzales, Ito, and Reguant 2023) (Larson et al. 2021). FERC has long required utilities to conduct transmission planning that addresses reliability, economic, and policy needs, ideally producing cost-effective regional projects. In practice, however, regional and interregional planning has been weak, hampered by unclear cost allocation rules, limited coordination, and permitting challenges. (Wayner, 2024).

A shortage of transmission capacity for new resources has left interconnection queues oversubscribed, studies unrealistic, projects withdrawn, and cascading restudies common resulting in a process that is long, uncertain, and costly, and in a grid that is ultimately less affordable and less reliable (Grid Strategies and Brattle, 2024).

2.3 Generation Interconnection Governance as a coordination problem

There is a grid paradigm shift underway. The PJM grid was designed for large, centralized fossil fuel plants to serve decentralized, small loads. Now the grid is experiencing a surge of small inverter-based generators and the connection of large loads such as data centers. Incumbent interconnection processes are ill-suited for this scale of application numbers and fuel types. Risk-adverse regulatory bodies such as PJM have a high degree of incumbency bias and may be skeptical of new processes and prevent niche technologies from adoption into the regime (Geels, 2007) Meanwhile rigid systems such as transmission infrastructure have a high degree of path dependency. The governance of generator interconnection is central to understanding both the opportunities and constraints of expanding ERIS adoption. FERC Order No. 2023, issued on July 28, 2023, represents the most significant reform to U.S. interconnection procedures in nearly two decades. The order was designed to alleviate severe queue backlogs, accelerate renewable and storage deployment, and ensure that transmission providers process requests in a more transparent and timely manner. It replaces the longstanding first-come, first-served model with a cluster-based first-ready, first-served approach, requiring projects to be evaluated in batches rather than individually. This structure is intended to better align study processes with the realities of high interconnection volumes while reducing the inefficiencies caused by restudies and speculative projects (Penrod, 2023) (Peppanen, 2020) Order 2023 also imposes stricter commercial readiness requirements, including higher financial deposits, proof of site control, and withdrawal penalties, to discourage non-viable projects from entering the queue. To increase transparency, transmission providers must publish public heat maps of available capacity, enabling developers to make more informed decisions. The rule establishes firm deadlines for completing cluster studies with penalties for missed timelines, creating new accountability for transmission providers. While these reforms are not explicitly targeted at differentiating ERIS from NRIS agreements, they have implications for both services. In particular, the single-phase cluster study requirement could either improve or diminish the relative time savings of ERIS agreements, depending on whether transmission providers create meaningful off-ramps for projects with minimal system impacts. Without such separation, ERIS projects may continue to be drawn into the same lengthy timelines as NRIS requests, limiting their potential advantages.

Chapter 3. Developer Decision Factors and Incentives

This chapter examines developer incentives to identify key factors shaping developer's ERIS versus NRIS decision. The synthesis of Chapter 3 with Chapter 4 will ultimately address *SQ1: What factors shape how developers choose between ERIS and NRIS agreements in PJM?*

Project developers generally make decisions by balancing potential profit against risk. In an unbundled electricity system, generation projects are developed to provide revenue for project owners, and developers are motivated to ensure those revenues outweigh costs. This requires not only that the project's finances add up, but also that developers operate within risk tolerances that give them confidence the project will yield a profit rather than lead to losses. Fundamentally, the trade-off for developers is the ability to interconnect more quickly with fewer network upgrades under ERIS agreements, in exchange for forfeiting access to separate capacity revenues that require NRIS agreements. Profitability in the interconnection process can be broken down into three main considerations: access to future revenue streams, the ability to secure financing, and anticipated network upgrade costs. Risk is closely tied to the uncertainty within each of these dimensions and whether revenues will materialize as expected, how volatile markets will be, how projects will be dispatched, and the unpredictability of network upgrade assignments (Liu, 2017). Each of these considerations is different based on the developers' own internal risk tolerance, project resource type, experience with PJM interconnection action situation, and internal financial considerations such as ability to hold debt for different durations.

3.1 Future Revenue

In PJM, generation projects may derive revenue from several sources: the energy market, the capacity market (available only to NRIS projects), renewable energy credits (for renewable projects), and ancillary service markets. The magnitude of this revenue depends on both project-specific factors and broader system conditions. The ability of the project to earn revenue to breakeven or earn profit over the lifespan of the project is a primary deciding factor that can be broken down into two sub factors (Snegirjovs, 2018). First is the *certainty* of the revenue: Will the project be curtailed by the RTO frequently and unpredictably or will it have guaranteed 100% transmission access? Will the energy market or capacity market be volatile or will they be constant over the course of the project's lifespan? Which market provides more certainty? The second subfactor is the *quantity* of the revenue. Will the project require capacity payments to be financially feasible? Will the project have enough transmission access to earn enough revenue over the course of the year, or will it be curtailed too frequently (Lam, 2018)?

3.1.1 Energy Market Revenue

Energy market revenue is the foundational source of income for most generation projects in PJM and is accessible to both ERIS and NRIS resources.

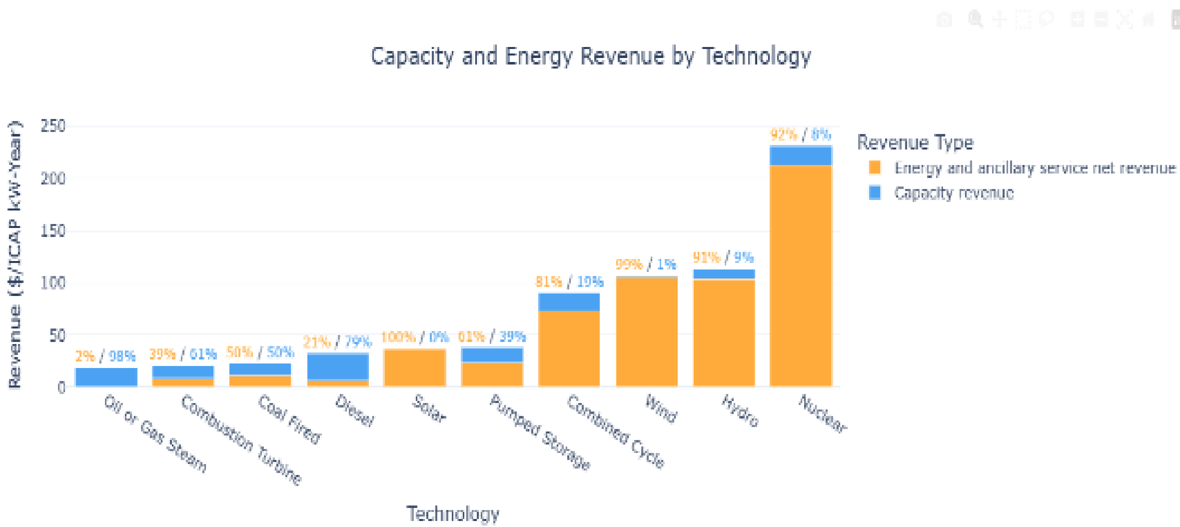


Figure 2: Capacity and Energy Revenue by Technology Type

Revenue is determined by the locational marginal price (LMP) at the project's node and the volume of energy successfully delivered to the grid. Several factors influence this outcome, including project-specific bid strategies, system-level congestion, and curtailment imposed during grid constraints. Projects with lower marginal costs often have a competitive advantage in the dispatch stack, but their realized revenue can still fluctuate significantly year-to-year due to market volatility, fuel price dynamics, and changes in regional demand. For renewable resources, which have near-zero marginal costs but are subject to variable generation profiles, curtailment risk and congestion constraints play a particularly important role in determining realized revenues (Reuter et al, 2012). Thus, while energy market participation is essential for nearly all projects, it provides an uncertain and often insufficient sole revenue stream, particularly in regions with high renewable penetration or transmission bottlenecks (Gatzert et al, 2016) (Prod, 2020). Furthermore, as the penetration of renewables increases, energy prices decrease to the extent that renewable expansion displaces the marginal generator (Milligan. 2016). A specific revenue stream from the energy market is relevant for storage resources: energy arbitrage. Arbitrage is purchasing energy (charging) when prices are low and selling energy (dis-charging) energy when prices are high (Byrne, 2016). Very little energy storage exists on PJM grid today, but high volumes remain in the queue.

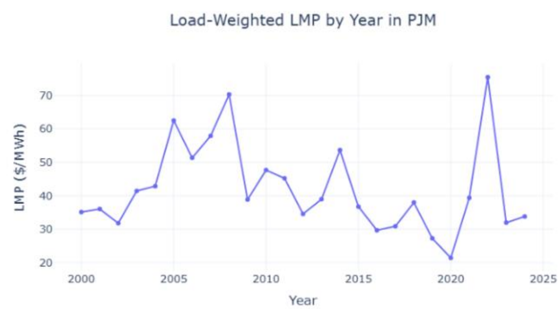


Figure 3: Load Weighted LMP by Year, PJM

Generation companies require an accurate forecasting of LMP to determine their operation and bidding strategy and determine preferred bilateral contract stipulations (Aggarwal, 2009) (Deb, 2000). Figure 4 plots fluctuation in yearly average LMP.

Volatility in LMPs across years, within a day, and across nodes introduces uncertainty and risk, especially as developers earn most revenues from the energy market.

3.1.2 Capacity Market Revenue

Capacity market revenue represents a secondary but potentially significant income stream for projects in PJM; however, it is available only to generators with NRIS agreements. Through the Base Residual Auction (BRA) NRIS projects can receive payments for committing to provide capacity during future delivery years. These revenues are designed to ensure resource adequacy and system reliability, but their attractiveness for renewable generation has declined as PJM increasingly applies Effective Load Carrying Capability (ELCC) adjustments that reduce the accredited capacity of variable resources. For many renewable developers, the declining ELCC values translate into reduced capacity payments relative to project capacity, making this market less compelling compared to the past. Additionally, year to year changes in ELCC valuation calculations make the market construct more incomprehensible (Christie, 2025). Nonetheless, for resources able to secure NRIS and achieve higher capacity accreditation, capacity payments can provide a stable, predictable revenue stream that complements the more volatile returns from the energy market.

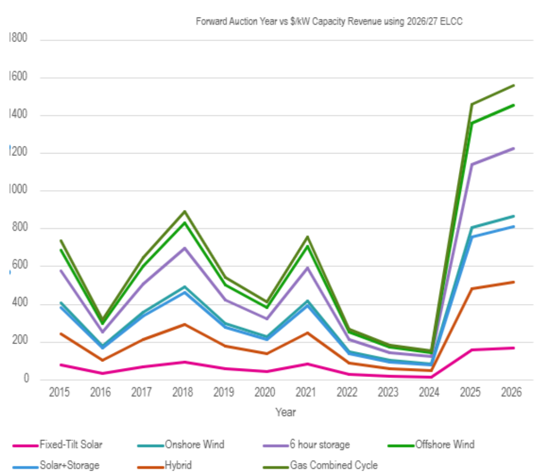


Figure 4: Forward Auction Year vs $/kW Revenue using 2026/27 ELCC

3.2 Ability to Secure Financing

The ability to secure financing is a critical determinant of whether a generation project in proceeds from the interconnection queue to commercial operation (Tsao, 2021). Energy projects typically require large upfront investment, and most will require some degree of debt or equity financing from lenders such as project sponsors or commercial banks. Financiers need confidence in future revenue before committing capital (Pacudan, 2016). Power Purchase Agreements (PPAs), which are long-term contracts between an energy buyer and an energy supplier, outlining the terms and conditions for the sale and purchase of electricity, can help facilitate the financing of a project. Access to PPAs is also a function of the buyer's perception of the project's revenue certainty (Kapral, 2024). Most projects rely on a mix of debt and equity financing, with the specific structure depending on the developer's financial standing, the perceived risk profile of the project, and the anticipated stability of future revenue streams (Mendelsohn, 2012). Large, well-capitalized developers often have stronger balance sheets that enable them to access lower-cost debt, tolerate longer development timelines, and absorb higher upfront network upgrade costs if necessary. In contrast, smaller or less established developers may face higher financing costs, more stringent lender requirements, or limited access to credit, making them more sensitive to interconnection delays and cost uncertainty.

Financiers evaluate projects based on both projected profitability and the certainty of those projections (Gatzert, 2016). Interconnection service type can directly affect this assessment.

NRIS projects, while often requiring higher upfront costs for network upgrades, may offer greater access to capacity revenues and more predictable dispatch rights, improving the perceived reliability of future cash flows. ERIS projects, by contrast, typically involve lower initial costs and faster timelines but carry greater exposure to curtailment risk and congestion, which may introduce uncertainty in revenue forecasts. Lenders and tax equity investors often discount projects with high uncertainty in either network upgrade cost assignments or market revenues, raising the cost of capital or delaying financial close.

Moreover, the developer's own risk tolerance and financing strategy interact with these external constraints (Karamoozian, 2022). Developers with limited capital reserves may prioritize quicker interconnection under ERIS to avoid long permitting and construction delays, while those with stronger financial backing may be willing to pursue NRIS agreements to secure additional revenue streams over the long term. In this way, financial standing not only shapes the range of viable financing structures but also influences the developer's strategic preferences within the PJM interconnection process.

3.3 Anticipated Network Upgrade Costs

The cost of the project relative to the revenue is one of the most critical factors in project success (Snegirjovs, 2018). NRIS agreements often involve more extensive transmission studies and may trigger significant network upgrade costs to ensure deliverability during peak load conditions. These costs can reach tens of millions of dollars, depending on the point of interconnection and regional transmission constraints. In contrast, ERIS agreements typically results in lower upfront interconnection costs, as it does not require deliverability studies or the same level of upgrades, making it more appealing for developers with limited capital or shorter timelines. Tax incentives and policy-driven subsidies can offset some capital costs, but they do not cover transmission upgrade costs, which are borne directly by the developer. The availability of low-cost financing can also affect whether a developer is able to absorb higher expenses (Cheng, 2017). Projects that can secure favorable financing, often tied to having long-term revenue certainty through a PPA. may be better positioned to afford an NRIS agreement. Conversely, developers with constrained financing or merchant market strategies may favor an ERIS agreement to minimize capital exposure, even if that introduces more operational risk. The interplay between interconnection costs, available incentives, and financing conditions shapes the financial feasibility of each interconnection path and is a key driver of the ERIS versus NRIS agreement decision.

Anticipated network upgrade costs are one of the most significant and most uncertain factors influencing developer decision-making in PJM's interconnection process. When a project seeks to connect to the grid, PJM conducts a series of studies to assess the reliability impacts and determine what transmission system reinforcements, if any, are necessary. These network upgrades can range from relatively minor local reinforcements to major regional transmission enhancements costing hundreds of millions of dollars. The assignment of these costs can have a decisive impact on a project's financial feasibility, often exceeding the capital expenditure of the generation facility itself. Not only are the final network upgrade costs uncertain during early project development stages, but also the allocation of these costs is subject to shifting queue dynamics and the decisions of other developers in the same study cluster. There are some economies of scale. Small projects seem to have lower total interconnection costs, medium-sized projects have usually the largest costs ($107/kW for complete, $246/kW for active and $660 for withdrawn projects) and the largest projects have only one-third to one-seventh of those costs (Seel, 2023). Projects may initially appear viable under one study scenario, only to become uneconomic if higher-cost upgrades are later triggered or if cost allocation is redistributed following project withdrawals. This trade-off is central to the interconnection decision: while NRIS agreements can unlock capacity market revenues and improve project dispatch certainty, they often come with greater upfront financial risk related to network upgrades. Developers' ability to anticipate and manage these costs depends heavily on their experience in PJM, access to detailed transmission planning data, and risk tolerance. Large developers with diversified portfolios may be able to absorb or hedge high-cost upgrades, while smaller developers may be forced to abandon projects. In this way, network upgrade costs not only shape project-level economics but also reinforce broader patterns of market participation and project attrition within PJM's interconnection queue.

3.4 Technical

The technical specifications of the project site relate to congestion of the transmission grid are an important consideration for ERIS versus NRIS agreements. If the point of interconnection has very little headroom, or the transmission lines are highly congested, generators would be curtailed more often than in an uncongested area. The site selected may have different levels of resource availability (for wind and solar for instance) impacting revenue stream, and different sites have different proximity to transmission infrastructure, impacting expenses related to interconnection (Goh, 2014).Different project types may have more tolerance for curtailment. For instance, solar-plus-storage projects can mitigate the financial impact of non-firm transmission service via energy arbitrage. This flexibility allows such projects to remain financially viable even where transmission access is not always guaranteed. Similarly, standalone storage projects or peaking resources may strategically operate during unconstrained hours (Springer, 2013). On the other hand, baseload or inflexible generation types, such as some thermal plants or hybrid projects with large capital costs and limited dispatchability may require more predictable access to the transmission system to ensure consistent revenue generation.

3.5 Timeline

The project's overall development timeline and its tolerance for interconnection-related delays is a key consideration when selecting between an ERIS or NRIS agreement (Cook, 2021). Delays can include length of interconnection study process, length of queue in front of them, and length of time from interconnection agreement to commercial operation date. NRIS often requires more extensive interconnection studies and may trigger more significant network upgrades, which can add several years to the project timeline. Developers with tight commercial operation deadlines or those pursuing near-term market opportunities (e.g., expiring tax credits, short procurement windows) may opt for ERIS agreements to avoid these delays (Delmore, 2025).

3.6 Emergent Developer Behavior

Beyond individual project economics, the collective behavior of developers within PJM's interconnection queue exhibits several emergent patterns that influence the distribution of projects and the overall dynamics of ERIS and NRIS selection. One such phenomenon is the use of interconnection applications as a cost discovery mechanism. Developers may submit multiple speculative projects in different transmission zones to assess upgrade costs and system constraints before committing to a final site or service level. This behavior contributes to the crowding observed in specific service territories, where applications concentrate not necessarily based on optimal resource siting alone but also on perceived opportunities for favorable interconnection outcomes.

Currently, approximately 80% of projects in PJM's queue are clustered within five service territories AEP, COMED, DOM, MEC, and JCPLC, which together represent only 28% of installed generation capacity (Figure 27). These regions attract significant developer interest due to a mix of high load growth expectations, favorable locational marginal prices (LMPs), and, in some cases, anticipated transmission expansion (MMR, 2024). This concentration reflects a chicken and egg dynamic: developers often target areas where transmission investment is planned or load growth is projected, while transmission planners may prioritize upgrades in regions where developer activity is already high.

In practice, this creates a feedback loop that reinforces congestion in certain areas, delays interconnection timelines, and increases network upgrade costs. Developers, in turn, adapt by clustering in zones that recently saw high levels of generation build-out, betting on incremental transmission improvements or policy-driven incentives to unlock capacity. As a result, emergent developer behavior shapes not only the economics of individual projects but also the evolution of PJM's interconnection landscape.

3.7 Summary

Chapter 3 used developer incentives to answer Subquestion 1: *What factors shape how developers choose between ERIS and NRIS agreements in PJM?* Developers in PJM choose between ERIS and NRIS agreements by weighing revenue amounts and certainty in the capacity and energy markets, availability of financing, and network upgrade costs against their own ability to face project delays, financial uncertainty, and high upfront costs. Chapter 4 will use institutional analysis for further factor identification.

Chapter 4: ABM Design via Institutional Analysis

This research's ABM is based on identifying and understanding the relationships between factors that inform or constrain project developer interconnection choice between ERIS and NRIS agreements. An ABM is typically developed in five iterative steps: (1) system analysis (problem/owner identification, system conceptualization, and system identification), (2) model design (structuring and behavior identification) (3) detail design (experimental design and logical model), (4) software implementation, and (5) model evaluation (experimentation and data analysis, verification, and validation) (Nikolic and Ghorbani, 2011). This chapter will conduct the first two of the five iterative steps by applying the IAD framework described in Appendix A to the PJM interconnection process to address Subquestion 1: *What factors shape how developers choose between ERIS and NRIS agreements in PJM?* and Subquestion 2: *How do developers respond to policy signals, peer behavior, and system constraints when selecting ERIS or NRIS agreements?*

The IAD framework outlines seven key variables in the action situation: the characteristics of the actors, their roles, the range of actions they can take and the potential outcomes, the cost and benefits of those actions and outcomes, the available information they have, and the level of control over their decisions. Over the course of this chapter each variable will be identified and analyzed for the purposes of the ABM.

Table 2: IAD Elements and ABM Application by Section

Section	Purpose	IAD Element	ABM Application
4.1	System Analysis	Action-situation	Process flow Model Structure
4.2	Behavior Identification	Attributes of Community	Logical model
4.3	Structuring	Rules-in-use	Interactions Evaluative Criteria

In Section 4.1 the relevant action situation will be explicated to set up the model structure and primary processes. Section 4.2 will analyze the attributes of the PJM interconnection process community in order to establish the logic of decision making of the model. Section 4.3 will explicate the rules in use and the related functions and variables in the model.

The factors and relationships identified through this analysis will then be used to inform the detailed design in Chapter 5 that includes experimental design, evaluative criteria, and development of reform scenarios.

4.1 System Analysis

The unit of analysis for the IAD framework application is the PJM generator interconnection process. This will be the "Action Situation" in which the primary participants are project developers and the PJM RTO (see Appendix A).

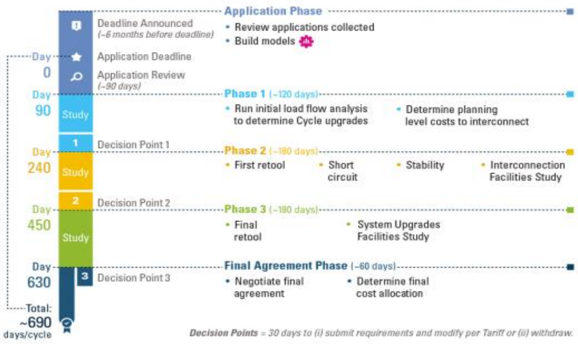


Figure 5: Clustered Cycle Process Overview, from PJM Manual 14H

The process of connecting to the existing transmission grid is a cluster study process, depicted in Figure 5. The process of interconnection begins when the project developer submits an interconnection request to the PJM RTO. As transmission provider and system operator, PJM RTO receives and acts on these applications for transmission service under the principle of open access (PJM OATT, 2025 sec.1.1). PJM RTO's studies determine any required upgrades that would not otherwise be necessary but for the interconnection of the new generators in the same cluster cycle. New generators are responsible for paying the cost of the facilities needed to interconnect the generator to the grid, as well as the cost of any transmission upgrades needed to resolve any impact to the system of the generator's interconnection. The interconnection process places increasing financial obligations on the developer, and it is up to the developer to evaluate these costs in terms of the project's viability. Developers may withdraw a project at each decision point. The end of the generator interconnection process is the execution of a Generation Interconnection Agreement for each remaining project. The agreement establishes the terms and conditions that will govern the interconnection and the rights that accrue to the generation developer (PJM Manual 14H, 2025).

ABM Application: Model Round Structure

The IAD Action Situation is translated into the ABM's general structure and processes. In the ABM, the system is PJM's interconnection process within PJM's operating territory. Each "round" represents a discrete interconnection application cycle which begins with a new batch of "Agents" each representing generation projects applying to connect to the grid. These agents are owned by individual project developers, who will submit projects each round. At the beginning of the round, each new agent chooses a "Node" that represents a transmission owner zone and elects either NRIS or ERIS service type. Meanwhile the "System" representing the PJM RTO conducts the interconnection studies which assign network upgrade costs, study time, and construction time to all project agents who can dropout during the study cycle. At the same time, the node signals congestion to the system based on the characteristics of the agents located at the node. At the end of each round, the system decides whether and where to build/expand transmission infrastructure based on congestion signals from the nodes. At the end of each round, the system runs a capacity market auction that results in a clearing price for NRIS resources. Finally, project agents who have been in the model for their assigned study time plus construction time, come “online”.

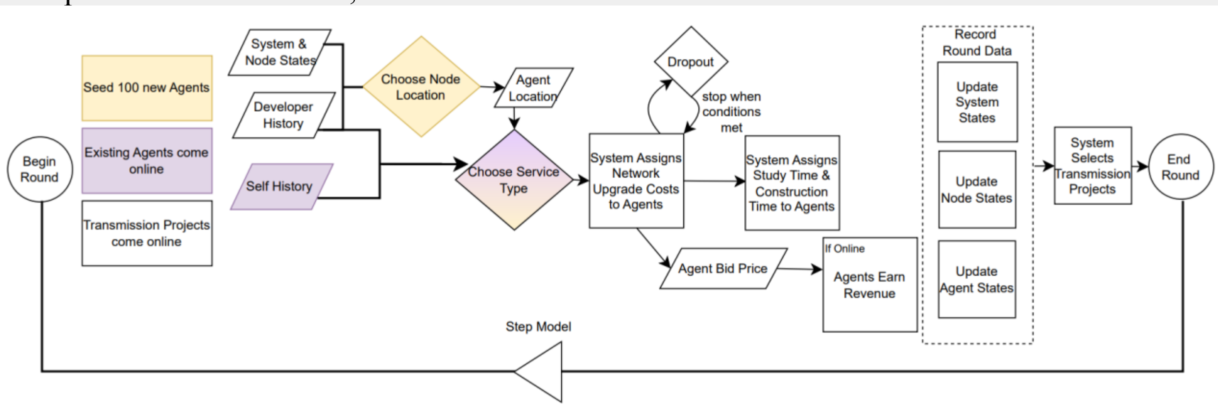


Figure 6: ABM Round Flow Diagram

ABM Application: Model Level Structure

Based on the IAD action-situation’s identification of system structure, the model happens on three levels (Figure 7). The first level is that of the system. The system is the PJM RTO. The second level is that of the nodes. The nodes are the transmission owner zones within PJM. The third level is the agents. The agents are the generation developers applying to the PJM interconnection queue. Each of these three levels have “states”. States are inherent characteristics that can either be static or dynamic. Each level influences the others via “interactions”(purple on Figure 7).

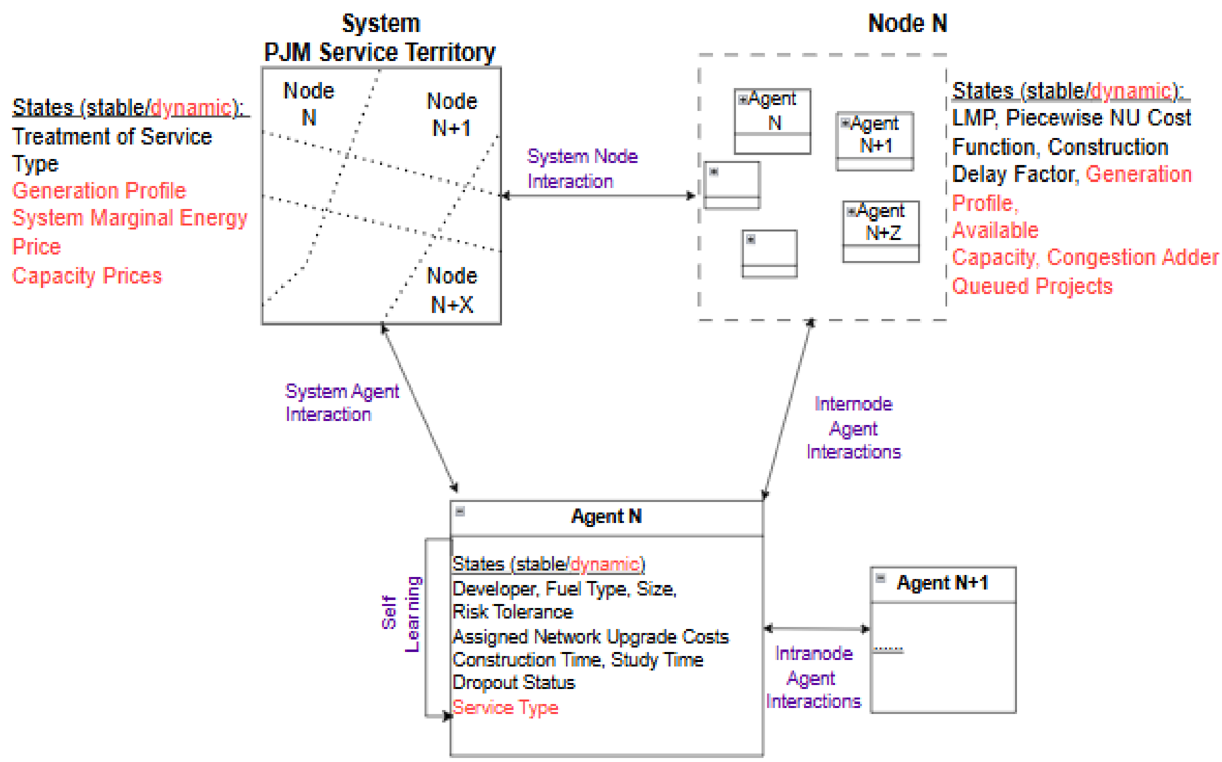


Figure 7: ABM Interaction Contexts

4.2 Behavior Identification

The IAD attributes of community encompass the social and cultural contexts in which the system operates, including demographic differences, values and norms (Ostrom, 2005). Additionally, it entails the preferences and beliefs of the participants related to the actions and outcomes of the action situation (Polski & Ostrom, 1999). In this section, the perspectives of the PJM interconnection action-situation participants are understood with particular focus on community attributes that could relate to ERIS versus NRIS decision making. In the ABM the system, node, and agent have “Behaviors”. Behaviors are actions that include making decisions, signaling their states, and changing states. These behaviors are listed in Table 3. The IAD attributes of community will be mapped to the behaviors in this section.

Table 3: Model Levels, States, and Behaviors

Level	**Description**	**States**	**Behaviors**
System	PJM RTO	Treatment of Service Type, Generation Profile, System Marginal Energy Price, Capacity Prices	studies interconnection requests, assigns network upgrade costs, builds transmission
Node	Transmission Owner Zones	LMP, piecewise NU Cost Function, Construction Delay Factor, Generation Profile, Available Capacity, Congestion Adder, Queued Projects	hosts projects, dispatches generation within node economically, signals congestion
Agent	Generation Project	Developer, Fuel Type, Size, Risk Tolerance, Assigned Network Upgrade Costs, Dropout Status, Construction Time, Study Time, Service Type	submitting project, making location decision, making ERIS/NRIS decision, dropping out of queue

The primary participants in the PJM interconnection process action-situation are the PJM RTO, the project developers, and transmission owners. While the state governments have some level of influence they were determined as not primary participants. See Appendix B for more discussion of the role of states.

PJM RTO: Roles, Values, and Governance

As the central coordinator of transmission planning, operations, and wholesale market oversight, PJM operates under the jurisdiction of the FERC. It does not own transmission assets but manages the regional grid in partnership with transmission owners, ensuring non-discriminatory access for all generators seeking interconnection. Through its Open Access Transmission Tariff, PJM is tasked with balancing three priorities: maintaining grid stability, facilitating new resource integration, and keeping costs reasonable for consumers.

PJM tends to exhibit a risk-averse operational philosophy, prioritizing predictability and proven reliability measures over experimental or market-driven approaches to congestion and system planning. The rapid increase in renewable energy sources introduces variability and intermittency, which complicates PJM's operations. The existing PJM processes were originally designed for a system dominated by large fossil-fuel generators supplying power to numerous small loads. The RTO also operated under a paradigm of nearly flat load growth. Today, however, the grid is transitioning toward numerous smaller renewable generators and serving rapidly growing, concentrated loads, such as data centers, which present new operational and planning challenges. PJM RTO is also slow to adapt and demonstrates some inflexibility due to the regulatory burden of updating study processes, for instance. Changes to processes aimed at encouraging ERIS adoption will be more likely when PJM struggles to fulfill its aforementioned roles, but only to the extent that the RTO can overcome its entrenched procedures and inherent bias toward the status quo—biases that are often mistakenly equated with reliability.

PJM's decision-making process is further shaped by their governance attributes. PJM operates under a two-tiered structure made up of the PJM Board of Managers and the Members Committee depicted in Figure 8. The PJM Board of Managers consists of nine voting members and the PJM CEO. The Board may have no relationship with, nor financial stake in, a PJM market participant. The Board ensures that PJM fulfills its business, legal and regulatory obligations, as well as runs a safe and reliable grid and operates fair energy markets. A Nominating Committee identifies candidates presented to members annually. The Members Committee, on which each member has a representative, provides advice to the board by proposing and voting on changes and new programs. Any company seeking to transact in PJM's wholesale power markets is required to become a member. The Members Committee is made up of five sectors with equal voting weights, see Figure 9. Each company designates a single voting member that is assigned to one of five sectors based on their primary business interest.

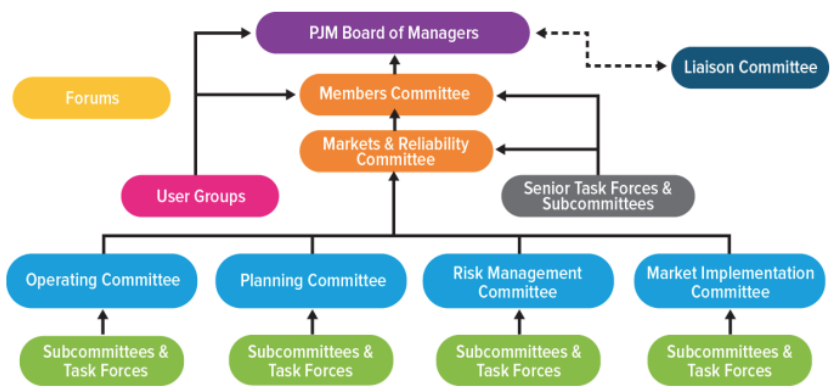


Figure 8: PJM RTO Organizational Structure (PJM Oversight and Transparency, 2025)

The Members Committee oversees the Markets and Reliability Committee which in turn oversees committees, subcommittees, and task forces. Stakeholders with a 10% or greater interest in multiple business interests can register affiliate members able to vote in PJM's lower-level subcommittees and taskforces that vet various discrete issues. However, affiliate members cannot vote at either the Markets and Reliability Committee or the Members Committee, thereby preventing larger companies from monopolizing the process.

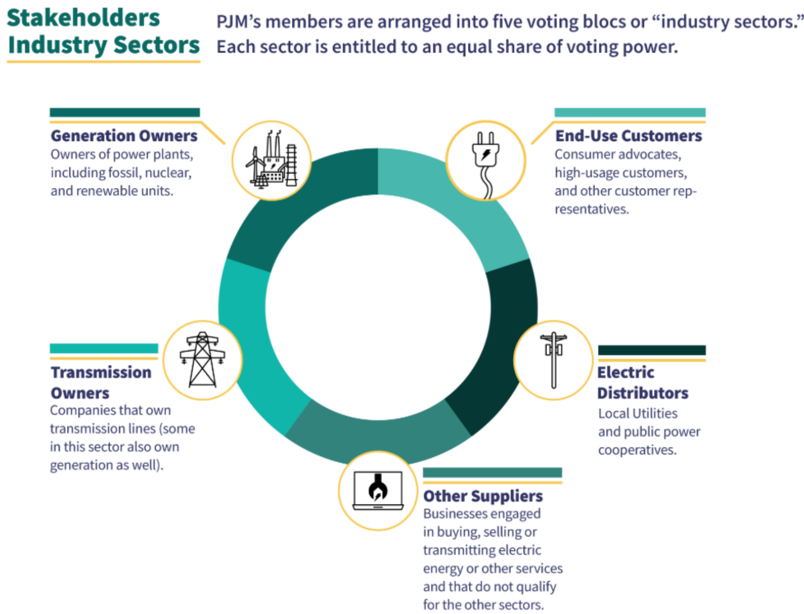


Figure 9: PJM Voting Sectors and Voting Weights (FERC Introductory Guide, 2025)

Any stakeholder, including a non-PJM member, can seek to bring an idea for consideration in the PJM stakeholder process, typically beginning by bringing a problem statement and issue charge to one of the technical committees. Both the Markets and Reliability Committee and Members Committee require a supermajority of two-thirds vote to pass anything. Ultimately, the PJM Board can determine whether the issue that has arisen through the committee process will get filed with FERC as a proposed change to the market rules or reliability rules governing PJM. PJM Board rulings are generally made by a majority of those present at the Board meeting. The Members Committee can also determine, upon a two-thirds supermajority committee vote, to file with FERC for change in any provision of a tariff, pursuant to section 205 of the Federal Power Act, even without PJM Board approval (MAREC, 2025) (OA 7.7).

PJM's preferences and beliefs are shaped by its mandate to ensure reliable, non-discriminatory transmission access and efficient market operation while remaining responsive to its diverse membership and FERC oversight. It is of note that PJM's governance structure is heavily influenced by stakeholders with direct financial interests in market outcomes, including incumbent utilities, merchant generators, transmission owners, and energy traders. Stakeholders with established revenue streams may resist reforms that could reduce their market advantages. Consequently, PJM's institutional culture is one of incrementalism, where reforms to interconnection, capacity, or transmission planning are implemented gradually, often through lengthy stakeholder negotiations and compromise rather than rapid, transformative action. PJM also values regulatory defensibility. In the context of ERIS versus NRIS agreements, this often translates into conservative network upgrade requirements and a cautious approach to granting firm capacity rights, even when such conservatism may slow renewable deployment or overestimate actual system risk.

ABM Application: PJM RTO Behaviors

The section above analyzed the attributes of PJM. These attributes inform how the behaviors are implemented at the System level in the ABM.

Table 4: PJM ABM Behaviors and Underlying Attributes

Level	Description	Behaviors	Underlying Attributes
System	PJM RTO	Studies interconnection requests, assigns network upgrade costs, and builds transmission	Reliability focused Change happens via regulatory compliance and stakeholder processes Incumbency bias

Transmission Owner Zones: Roles and Values

Transmission Owner Zones are run by Transmission Owners (TOs) in PJM. TO's form a distinct community within the interconnection process, bound by shared responsibilities, incentives, and regulatory constraints. As owners and operators of the transmission lines, substations, and related infrastructure, TOs collectively provide the technical backbone necessary for projects to interconnect and directly shape how much capacity is available and which network upgrades are required for developers. TOs coordinate with PJM and adhere to FERC oversight, but exert influence over project timelines, sequencing, and cost through their control of upgrade design, permitting, construction, and procurement processes. TOs are responsible for estimating upgrade costs, managing internal schedules, and allocating engineering and construction resources, which collectively determine how quickly interconnections can be completed and at what expense. TOs do not earn a return on equity for the network upgrades that the new generators are paying for. However, TOs generally favor connecting new generation to their grid, because this can lead to subsequent large transmission buildout needs, the investment in which can earn a return on equity for the TOs. Some large companies own both generation and transmission systems in PJM. TOs also are members in the Members Committee and thus vote directly on issues.

ABM Application: Transmission Owner Zone Behaviors

The section above analyzed the attributes of Transmission Owners. These attributes inform how the behaviors are implemented at the Node in the ABM

Table 5: Node Behaviors and Underlying Attributes

Level	**Description**	**Behaviors**	**Underlying Attributes**
Node	Transmission Owner Zones	hosts projects dispatches generation within node economically signals congestion	Favor transmission infrastructure expansion Designated technical experts Subject to regulation

Project Developers

Project developers' primary objective is to achieve successful interconnection of generation projects while managing costs, risks, and timelines. Some project developers may also be generation owners and sit on the Members Committee of PJM. Developers range in incumbency, experience, financial risk tolerance, and geographic specialization or generality. Developers are generally risk-sensitive, valuing regulatory predictability and transparent cost allocation. Many adopt speculative strategies such as submitting multiple queue positions or seeking sites they perceive to be near available headroom to hedge against PJM's protracted timelines and uncertain upgrade responsibilities. Despite competition, there is also evidence of collective behavior: developers frequently advocate for policy reforms, share intelligence through industry groups, and push for greater transparency in interconnection studies. As a community, developers are constrained by asymmetric information, capital intensity, and regulatory complexity, which shape their behavior in the action arena. Their ability to influence outcomes often depends on aligning with broader stakeholder coalitions (e.g., renewable advocacy groups, storage developers) and leveraging procedural reforms to secure fairer cost allocation and more predictable interconnection pathways. The specific factors influencing the project developers ERIS and NRIS decision making are evaluated comprehensively in Chapter 3.

ABM Application: Project Developer Behaviors

Table 6: Project Agent and Underlying Attributes

Level	Description	Behaviors	Underlying Attributes
Agent	Project Developers	submitting project, making location decision, making ERIS/NRIS decision, dropping out of queue	Profit motivated Variable risk tolerance Information limited

Community Attribute Summary

The PJM interconnection process operates within a diverse and complex community of actors whose values, norms, and institutional structures shape outcomes. PJM RTO, as the central coordinator, emphasizes reliability, regulatory defensibility, and incremental reform, often favoring traditional network upgrades and risk-averse planning approaches. TOs provide the technical backbone of the grid and exert influence through cost estimation, upgrade construction, and voting power within PJM's governance structure, with financial incentives that can affect project prioritization. States wield indirect but growing influence by setting policy targets, approving siting and permitting, and applying political pressure to reduce capacity prices and accelerate renewable integration—at times threatening to reshape or exit PJM governance. Project developers navigate this landscape with varying levels of risk tolerance, often employing speculative strategies to secure queue positions, while collectively advocating for reforms that offer greater transparency, fairer cost allocation, and predictable interconnection timelines. These overlapping and at times conflicting community attributes create friction in the interconnection process particularly where conservative system planning norms meet dynamic market and policy demands.

4.3 Rules-in-use

The interconnection process in PJM is governed by a set of formal and informal rules that shape actor behavior, known as rules-in-use in the IAD framework. Rules-in-use span seven categories (McGinnis, 2016) (Table 7)

Table 7: Rules-in-use governing the Relationship Between PJM RTO and Project Developers in Interconnection

Rule Type	PJM RTO	Project Developer
Position Rule	*specifies a set of positions, each of which has a unique combination of resources, opportunities, preferences, and responsibilities*	
	Acts as grid operator Non-discriminatory open access Maintain electric reliability	Selects point of interconnection and specifies service type
Boundary Rule	*specifies how participants enter or leave positions*	
	-	Must meet application requirements, site control and financial milestones, and pay for allocated connection costs
Choice Rule	*specifies which set of actions is assigned to which position.*	
	-	Remain in queue or dropout Construct project or not (if has GIA)
Information Rule	*specifies the information available to each position.*	
	Provides capacity heatmap Publishes Ix study results	Applications are public
Aggregation Rule	*Specifies the transformation function from actions to intermediate or final outcomes.*	
	Study methodology Cost allocation methodology	-
Payoff Rule	*Specifies how benefits and costs are required, permitted, or forbidden to players*	
	Dispatch Runs Capacity Market	Participation in wholesale electricity market (and) capacity market
Scope Rule*	*Specifies set of outcomes*	
	GIA must not create unreliability	-

*Scope rules will be included in Section 4.4 as scope rules involve outcomes

Position Rules

The PJM RTO has four required characteristics and eight minimum functions (FERC Order No. 2000). These characteristics and functions serve as the position rules for PJM RTO in the IAD framework. The most relevant of these position rules for the interconnection action-situation are bolded.

Required Characteristics of PJM
PJM must…

- be independent of all market participants and have no financial interest in the economic outcome of the market.
- be configured over a region of sufficient size to perform its functions and support efficient electricity markets.
- **have operational control over all transmission facilities within its region.**
- **have the exclusive authority to maintain the short-term reliability of the grid.**

Minimum functions of PJM
PJM must…

- **administer a single Open Access Transmission Tariff (OATT) and serve as the single point of contact for transmission customers.**
- have the authority to manage transmission congestion through fair and non-discriminatory procedures.
- be responsible for planning and coordinating regional transmission expansion, ensuring an efficient and reliable grid.
- operate both a day-ahead and a real-time market to facilitate the efficient buying and selling of wholesale power.
- provide and manage the ancillary services necessary to support grid reliability.
- have a market monitoring function to identify and address any market power abuse or other anticompetitive behavior.
- coordinate with neighboring RTOs and other balancing authorities to ensure reliability and efficiency across regional boundaries.
- have procedures for allocating and managing transmission rights, including financial transmission rights

PJM RTO is governed by three primary documents: the PJM Open Access Transmission Tariff which sets the rates and terms of service within PJM, the Reliability Assurance Agreement which outlines the rights and responsibilities of load serving entities, and the Operating Agreement: a series of bylaws describing PJM's governance structure and the rights and responsibilities of the members, independent board, and PJM staff.

Project developers also have position rules which specify their responsibilities and opportunities, in the interconnection process. Any project developers wishing to apply to interconnect a new generation facility to the Transmission System in the PJM region may initiate a New Services Request, by following the Queue Point Application Process (PJM Manual 14A). In doing so they specify their position by indicating technical specifications of the project, the requested point of interconnection, and the service type (ERIS or NRIS agreement to be studied). PJM membership is required prior to commercial operation.

ABM Application: Position Rules

The System accepts all projects agents into queue cycle
Agents must execute the choose_node() function which is outlined in information rules section
Agents must execute the choose_service_type() function described in Figure 10

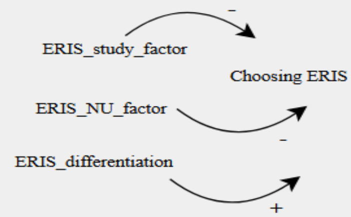


Figure 10: Variable relationships in choose_service_type()

Boundary Rules

The interconnection study process serves as a boundary condition itself to accessing the transmission service in PJM. To remain in the interconnection queue and receive an interconnection service agreement, project developers must meet milestone requirements along the way. Each step imposes its own financial obligations and establishes threshold requirements.

Table 8: Rules to remain in queue process at each PJM Cycle Decision Point

Decision Point	Requirements to remain in process
Decision Point 1	Readiness Deposit $4,000/MW Evidence of site control Evidence of air and water permits (if applicable) Submission of data for Phase II System Impact Study
Decision Point 2	Readiness Deposit of 10% of network upgrade costs Submission of data for Phase III System Impact Study Evidence that project developer has interred into affected system study agreement (if required)
Decision Point 3	Readiness deposit of 20% of NU costs 100% site control Evidence of any necessary permitting MOU for acquisition of major equipment

ABM Application: Boundary Rules

Agents execute the function dropout()

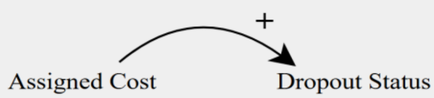


Figure 11: Variable Relationships in dropout()

Choice Rules

Choice rules outline what actions must, may, or may not be taken by a participant in a given position, depending on the conditions present. Once the interconnection process begins the project developers have limited choices. They may withdraw at any point, although financial withdrawal penalties increase as the process progresses. Additionally, very limited modifications are permitted at decision points 1 and 2 only such as reducing the requested output, removing one fuel type from a request with multiple fuel types, limited changes to the point of interconnection (only at decision point 2), moving to adjacent land parcel, and updating equipment data (PJM Manual 14H, 9.8).

ABM Application: Choice Rules

Agents execute the functions dropout() and come_online()

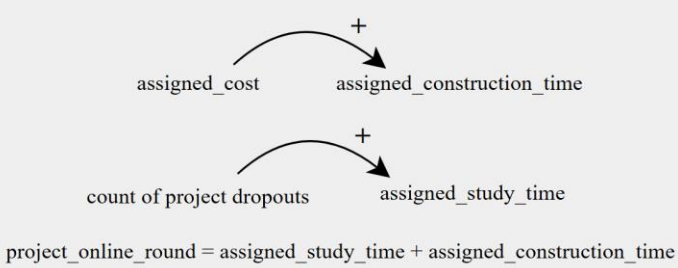


Figure 12: Variable relationships in come_online()

Information Rules

Information rules govern the access and authorization of information exchange among participants. PJM RTO must publish the results of their studies and provide project developers with the base cases used to develop study results. Additionally, under FERC Order 2023, PJM RTO must maintain a publicly available visual representation, also known as a heatmap, of available transmission capacity. FERC intends for the heatmaps to benefit prospective interconnection customers by helping them to identify ideal points of interconnection based on areas of expected congestion. PJM RTO does so through the Queuescope platform, but it has limited accuracy as it does not incorporate currently queued project impacts, and it still has a high degree of uncertainty.

ABM Application: Information Rules

Agents execute the function choose_node()

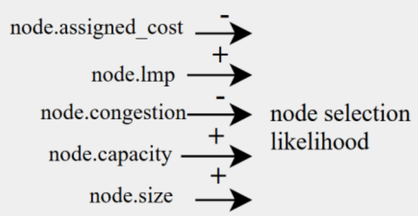


Figure 13: Variable relationships in choose_node()

<u>Aggregation Rules</u>

Aggregation rules specify the transformation function from actions to intermediate or final outcomes. In this case, the transformation from interconnection applicant choices to final outcomes occurs via the PJM RTO's study process and cost allocation. Lack of differentiation between NRIS and ERIS agreements in these rules and uncertain cost allocation in combination with strict contingency analyses resulting in high network costs, disincentivize the pursuit of ERIS agreements. The PJM RTO follows a phased technical study process prescribed in Manual 14A. The study process consists of a feasibility study, system impact study, and interconnection facilities study. PJM in the position of study conductor must take the characteristics of the applicant generators and assign network upgrades and costs based on the results of their studies. The stringency and contingency analysis in particular and choices of base cases have significant effects on the study outcomes.

System Impact Studies

The system impact studies identify the system constraints. These studies provide estimates of cost responsibility and construction lead times for the new facilities required to interconnect the project and system upgrades. In situations where more than one generation project violates reliability criteria, cost responsibility for network upgrades will be allocated among the projects. A significant part of the system impact studies is running different contingency scenarios. North American Electric Reliability Corporation (NERC) is a regulatory authority that develops and enforces reliability standards. NERC Standard TPL-001-1 (Transmission System Planning Performance Requirements) proposes several requirements for demonstrating reliable operation of the power system over the planning horizon. PJM has chosen to incorporate some of these contingency scenarios into assigning network upgrades for new generation request

Table 9: System Impact Study Rules

Phase	Study Procedures and Content
P1 SIS	• Studied under summer peak, winter peak, light load Regional Transmission Expansion Plan base case • Load flow (AC contingency) analysis: NERC TPL P01, P1,P2, P4,P5,P7 • Light Load analysis: NERC TPL P1,P2,P4, P5, P7, P0 • Affected system* screen • Create short circuit and stability base case • Requests that change system topology are subject to P3 N-1-1 analysis
P2 SIS	• Retool load flow results from P1 based on any changes since P1 • Affected system study • Voltage analyses (PJM Manual 14B, section 2.3.7) • Short circuit analysis (PJM Manual 14B, section G.7) • Stability Analysis
P3 SIS	• Retool load flow, short circuit and stability results from P2 based on changes since P2 • Affected system* study

* "Affected System" is an electric system other than the Transmission Provider's Transmission System that may be affected by a proposed interconnection or on which a proposed interconnection or addition of facilities or upgrades may require modifications or upgrades to the Transmission System.

The PJM study process is manual, resource-intensive, and time-consuming, requiring detailed attention from engineering staff without systematic automation. The scope of analysis extends far beyond simple generator connection to include wide-area transmission impacts, often under highly conservative conditions. In particular, the inclusion of N-1-1 analysis, which requires double contingency reinforcement, significantly raises the number and cost of required upgrades. Moreover, any network upgrade classified as "topology-changing" can trigger these more stringent studies, amplifying both developer uncertainty and cost exposure. Topology changing upgrades are modifications of the transmission network that alters how power flows through the system such as reconfiguring existing transmission lines, installing or removing a transformer or switching equipment, addition of new bus, or substation changes. This level of conservatism often leads to very high network upgrade requirements, delayed processing timelines, and increased project attrition.

Facility Studies

Facility studies are conducted by the relevant transmission owner to determine the specific modifications needed on PJM's Transmission System in order to implement the conclusions of the System Impact Studies (SIS). These studies translate the identified network upgrades and interconnection facilities into detailed engineering plans, cost estimates, and construction timelines. Importantly, the proposed solutions can be influenced by regulatory requirements, including the consideration or application of Advanced Transmission Technologies (ATTs), which may affect the configuration or scale of required upgrades.

Cost Allocation

One of PJM's responsibilities as an RTO is to allocate cost responsibility for all system reinforcement projects, including those required for new service requests. Each generator or transmission project bears the cost of Interconnection Facilities required for its interconnection. For network upgrades identified through each phase of SIS, "the cost of the network upgrades will be allocated according to the contribution of each individual new service request for those projects which contribute to the need for the network upgrades"(FERC ER24-2024-000, 2025). However, FERC's disagreed with this procedure, finding that "currently, PJM's Tariff requires an interconnection customer to pay for 100% of the network upgrades necessary to accommodate its interconnection request, as well as 100% of the costs of the interconnection facilities, but PJM's Tariff does not describe how the costs of each type of system network upgrade will be allocated among the interconnection customers within the cluster… we direct PJM…to revise the Tariff to describe the method transmission providers will use for allocating costs of each type of system network upgrade"(FERC ER24-2024-000, 2025). It remains unclear how, when, or if PJM will implement this guidance, adding further uncertainty and potential financial risk for developers participating in clustered interconnection studies.

ABM Application: Aggregation Rules

The System (PJM RTO) executes the functions assign_study_time() and assign_costs()

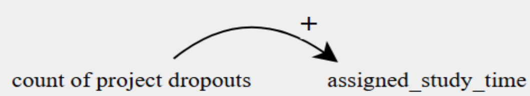


Figure 14: Variable relationships in assign_study_time()

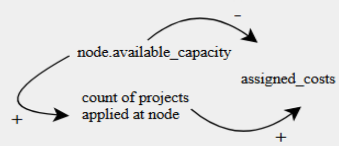


Figure 15: Variable Relationships in assign_costs()

<u>Payoff Rules</u>

Project Developers who choose ERIS or NRIS service type and successfully receive a generation interconnection agreement means that the project developers have the benefit of access to the wholesale electricity market. Only NRIS projects will have the benefit of access to the capacity market. The structures of these markets and their benefits to project developers are discussed below.

Wholesale Electricity Market

The PJM RTO does not distinguish between generator interconnection service types in real-time operations. ERIS and NRIS agreements are treated on a level playing field for curtailment priority with respect to both congestion-related curtailment and system emergency response. This is because PJM dispatches based on competitive economic dispatch and real-time contingency management. Capacity resources have no right to preferential dispatch in real-time and day-ahead energy markets, irrespective of system conditions (Norris, 2024). Connection to the grid means that project developer's projects are dispatched and earn revenue from the wholesale market in the magnitude of their LMPs. PJM runs a day-ahead and real-time wholesale market. LMPs represent the incremental cost of supplying one additional megawatt of energy at a specific bus on the grid and closely track the marginal costs of the units setting the market price. In terms of market dynamics, the mix of marginal resources shaping LMPs in PJM's Real-Time Energy Market during 2024 was dominated by natural gas units at 73.7% and coal units at 13.5%, with the remainder primarily made up of wind generation (Market Monitoring Report, 2024). LMP is composed of three components: the system marginal price, the congestion component, and the marginal loss component. One payoff of grid connection is access to energy revenues.

The Capacity Market

PJM's capacity market is a three-year-forward auction mechanism designed to secure sufficient capacity to meet federally mandated reliability requirements at least cost. PJM administratively sets demand based on forecasted peak load and accredited capacity ratings, which reflect expected resource performance during extreme conditions and high-outage events. The auction clears at the marginal price where supply meets demand, with all accepted resources (generators or demand-side participants) receiving that clearing price. In 2024, FERC approved PJM's adoption of the marginal ELCC method to more accurately measure a resource's contribution to reliability, resulting in lower accredited capacity values for natural gas, wind, solar, and storage resources compared to PJM's prior method. Most capacity resources are subject to a must-offer requirement. In late 2024, FERC approved PJM's proposed price cap of $325/mw-day with a $175/mw-day price floor for the next two auctions. The 2026/2027 auction failed, and the price hit the cap at $325/mw-day, as shown in Figure 16.

	Auction Results				
Delivery Year	Resource Clearing Price	Cleared UCAP (MW)	RPM Reserve Margin[1]	Total Reserve Margin[1,2,7]	Cleared MW Times Clearing Price ($ billion)
2016/17[3]	$59.37	169,159.7	20.7%	20.3%	$5.5
2017/18	$120.00	167,003.7	20.1%	19.7%	$7.5
2018/19	$164.77	166,836.9	20.2%	19.8%	$10.9
2019/20	$100.00	167,305.9	22.9%	22.4%	$7.0
2020/21[4]	$76.53	165,109.2	23.9%	23.3%	$7.0
2021/22	$140.00	163,627.3	22.0%	21.5%	$9.3
2022/23	$50.00	144,477.3	21.1%	19.9%	$3.9
2023/24	$34.13	144,870.6	21.6%	20.3%	$2.2
2024/25	$28.92	147,478.9	21.7%	20.4%	$2.2
2025/26[5]	$269.92	135,684.0	18.6%	18.5%	$14.7
2026/27[6]	$329.17	134,205.3	18.9%	18.9%	$16.1

[1] Reserve Margins converted to ICAP using Pool-Wide AUCAP Factor; [2] Total Reserve Margin includes FRR+RPM (Total ICAP/Total Peak-1); [3] 2016/2017 BRA includes EKPC zone;
[4] Beginning 2020/2021 Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers; [5] DOM zone included in RPM; [6] EE removed from Market; [7] Total Reserve margin does not include FRR commitments to meet the threshold to allow sales into RPM.

Figure 16: RPM Clearing Price Results (PJM BRA, 2025)

The capacity market does not provide an effective signal for new investment. While high prices should incentivize the development of additional generation, the 5–10 year lag caused by the interconnection queue allows incumbent generators to earn increasing profits on existing assets, paid for by electricity customers, without accelerating the deployment of new resources. High-capacity market prices, however, do incentivize developers to apply as NRIS resources especially if their resource types has high-capacity accreditation, to the extent that developers believe capacity market prices will remain high into the future once they are connected to the grid and for the operational life of their project.

ABM Application: Payoff Rules
The System (PJM RTO) executes the function update_capacity_market_price()

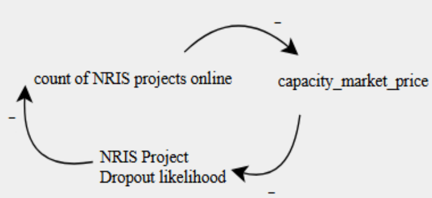


Figure 17: Variable relationships in update_capacity_market_price()

4.4 Outcomes

The outcomes in PJM deserve enumeration to understand how the current system operates to result in outcomes some of which are antithetical to the policy goals of PJM RTO.

Scope Rules
Scope rules delineate the spectrum of potential outcomes that may be influenced. Critical outcomes of the interconnection action situation are (1) which project developers receive interconnection agreements (2) what network upgrades are assigned to the generation projects, (3) how the costs are allocated among projects for the network upgrades, and (4) how much time the process takes.

(1) Generator Interconnection Agreements As: The project developers that receive interconnection agreements are those which met the requirements of PJM throughout the study process and chose not to drop out
(2) Process Duration: The length of time the study process takes is capped at 590 days, but could be shorter (PJM May 16th FERC Order 2023, Compliance Finding)
(3) Network Upgrades: The assigned network upgrades are a result of the PJM study details (described in choice rules)
(4) Cost allocation: PJM proposed retaining its existing Tariff, which allocates 100% of cluster study costs on a per-capita basis among interconnection customers in a cluster or cluster area. However, this approach does not comply with FERC Order Nos. 2023 and 2023-A, which require that 10–50% of study costs be allocated on a per-capita basis and the remaining 50–90% on a pro-rata basis. Accordingly, PJM's request for an independent entity variation to continue 100% per-capita allocation was denied, as the existing Tariff was not demonstrated to be just, reasonable, and non-discriminatory. It remains to be seen when, if, or how, PJM will amend their cost allocation methodology to be in compliance with FERC Order 2023.

The outcomes defined by the scope rules are the GIAs (how many and to whom), the process duration, the network upgrades, and the network upgrade cost allocation. These outcomes are readily available from PJM data.

GIA outcomes can be visualized by the amount of new service that is brought on each year, and the process duration by the amount of time it took between a developer applying to get connected, and actually being online. On average the added generation per year in PJM has hovered between two and six MW.

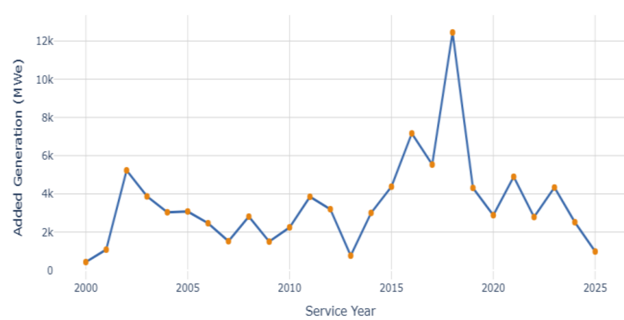


Figure 18: Added Generation (Mwe) by In-Service Year 2000-2025(Data from PJM BRA, 2025)

Most projects that enter PJM's interconnection queue do not end up in service (Figure 19). No data is yet available for project completion post 2018, since 2018 demarcates the beginning of the yet ongoing Transition Cycle 1. Since 2008, less than half of projects have come online, with an average of 24.8% in the last five years of available data. Additionally, the median time in queue for the last five years of available data is around 3.84 years between submission and in service.

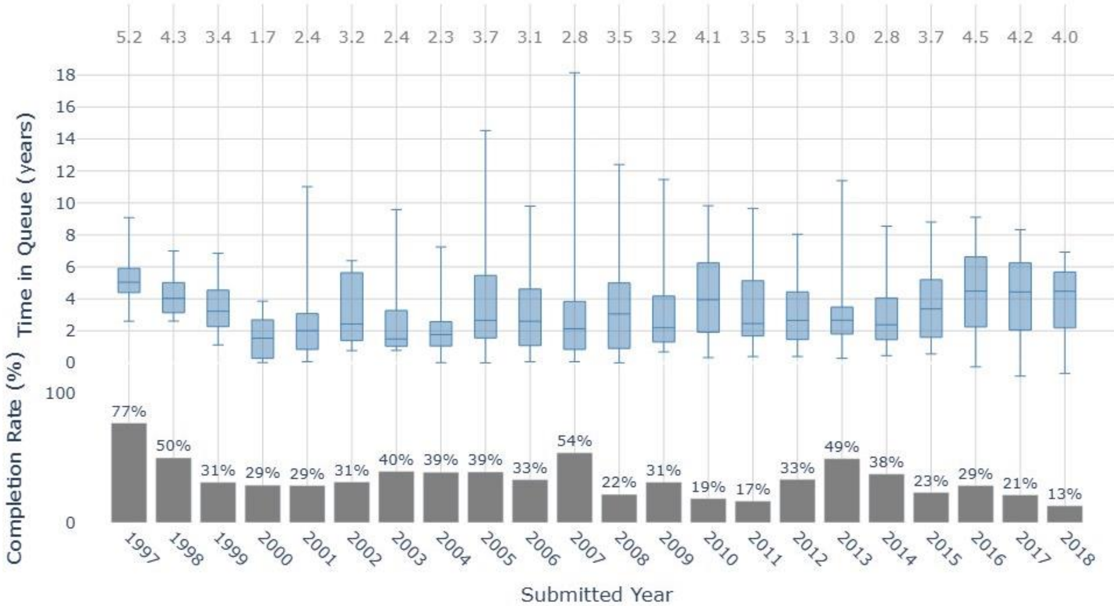


Figure 19: Completion Rate and Time in Queue by Submitted Year of Generator Interconnection Applications (Data from PJM Serial Service Status, 2025)

Another way to understand the GIA outcome is by the type of GIAs that were awarded: ERIS or NRIS. The amount of existing service that is ERIS is less than 1% (LBNL, 2024) reflecting a small number of ERIS GIAs. In the most recent application cycles, ERIS project applications represent less than 3% of the total application cycle size inMW.

Table 10: ERIS Characteristics in Transition Cycle 1 and 2 (Data from PJM Cycle Service Status, 2025)

Interconnection Cycle	ERIS/Total Projects	ERIS/Total GWe	ERIS Technology Types
Transition Cycle 1	5/293 (1.7%)	1.06/40.3 (2.6%)	4 solar, 1 storage
Transition Cycle 2	27/601 (6 have withdrawn) (4.5%)	.605/61.57 (<1%)	1 gas, 1 solar, 25 battery (21 active battery)

The assigned network upgrade costs are only available for Transition Cycle 1 projects. These costs are more than three times higher than those assumed in a U.S national lab's annual technology capital expenses calculations (NREL ATB, 2025). In conjunction with a high percentage of projects dropping out, which tend to be assigned higher than average network upgrade costs, this suggests that the costs are too high for many developers to justify remaining in the queue.

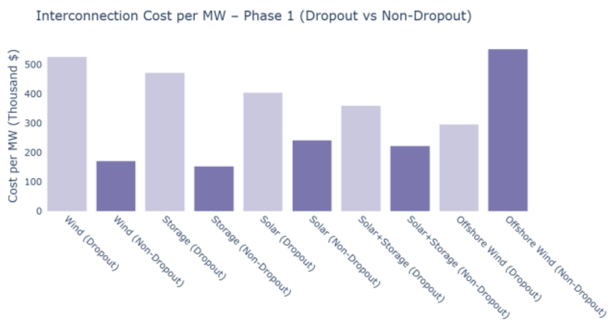


Figure 20: Network Upgrade Costs by Technology Type and Dropout Status (Data from PJM Cycle Status, 2025)

There is some limited positive indication that PJM RTO may assign slightly less expensive network upgrades to ERIS projects.

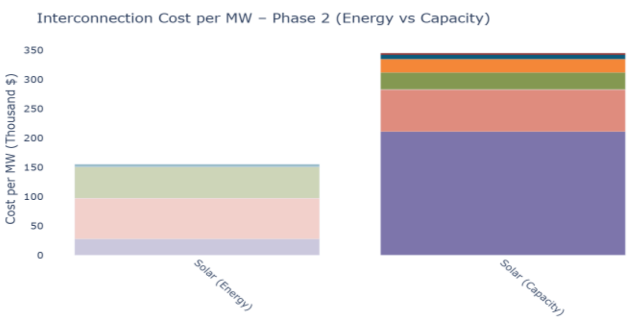


Figure 21: Network Upgrade Costs ERIS vs NRIS in TC1 Phase 2 (Data from PJM Cycle Status, 2025)

The most recent data available from Interconnection Transition Cycle 1 shows solar ERIS projects being assigned less than half the costs of solar NRIS projects, though the sample size is very small (5 ERIS projects)(Figure 21)

Table 11: Average Assigned Network Upgrade in TC1 by Phase, Technology and Service Type (Data from PJM Cycle Service Status, 2025)

Interconnection Cycle Phase	**Solar NRIS** ($/MW)	**Solar ERIS** ($/MW)	**Solar+Storage NRIS** ($/MW)	**Solar+Storage ERIS** ($/MW)
TC1 Phase 1	295.5$	$418.96 (not ERIS yet)	$274.79	381.086$ (NRIS in Phase 1)
TC1 Phase 2	$345.07	$155.80	(the one hybrid project switched to solar only in Phase 2)	

Transition Cycle 1 shows more expensive network upgrades for ERIS projects in phase one, but this is reduced in phase 2. (Table 11)

ERIS agreements remain uncommon, and elevated upgrade costs have contributed to high project attrition.

ABM Application: Evaluative Criteria

This section describes the evaluative criteria that will be used to analyze the outcomes of the model under baseline and reform scenario model runs described in Chapter 6 and Chapter 7.

Standardized evaluation criteria across scenarios allows comparison of the results from different experiments to provide answers to Subquestion 3: *How do developers respond to policy signals, peer behavior, and system constraints when selecting ERIS or NRIS agreements under different scenarios?* These indicators will also be critical in addressing Subquestion 4: *How could targeted reforms shift developer behavior and improve interconnection outcomes in PJM?*

Table 12: ABM Key Performance Indicators

Key Performance Indicator	Unit	Description
Service Type Selection	%, MW	Percent of projects in each round that select ERIS and NRIS by number of projects and also by total size of projects
Dropout Rate by Service Type	%, #, MW	Percent of projects in each round that do not dropout number of projects, size of projects, and service type
New Online Projects	MW	The number and MW of projects that are brought online each round
Capacity Price	$/MW-day	Clearing price of the capacity market each round
Installed Capacity	MW	The total installed capacity on the grid each round
Available Capacity	MW	The capacity available across the system for new generation projects
Network Upgrade Costs	$/MW	The expense assigned to generation projects each round to connect to the grid
Study Time	Rounds	The amount of time it took from application to generation agreement each round, grouped by project service type selection
Construction Time	Rounds	The construction time assigned to each project and on average, grouped by project service type selection

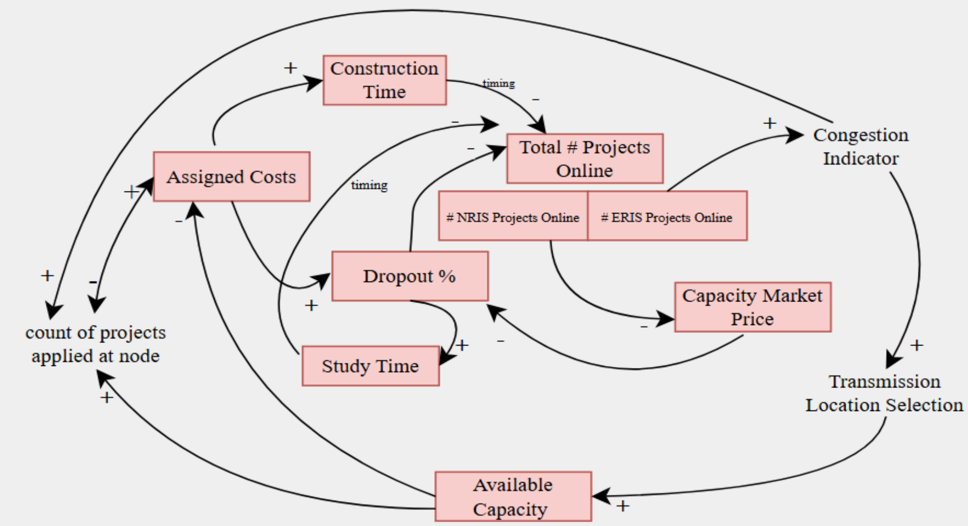


Figure 22*:* Causal Loop Diagram of ABM with Outcomes

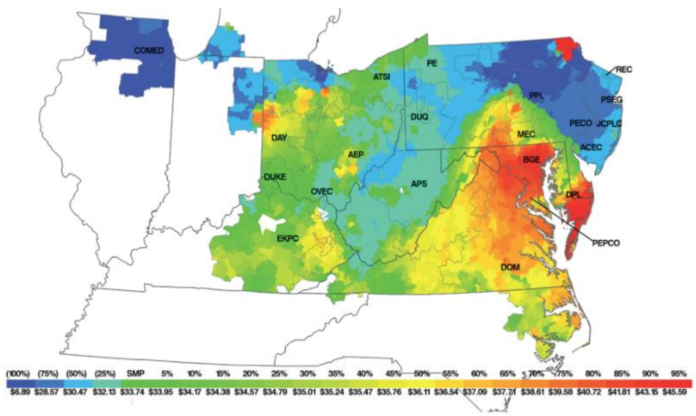
Chapter 5. Experimental Design

With the system analysis conducted, and basic model structure, behaviors, and key outputs identified, this chapter covers the experimental design of the model, physical, and material conditions of the PJM grid. The experimental design will also include incorporating PJM data as inputs for the states of the developer and node level actors. The previous section outlined the model conceptually by identifying key actors, factors, interactions, and processes. The following section will detail the model inputs required to initialize and calibrate the model for experimentation. A model cannot fully represent reality, but it can approximate the most salient mechanisms and trade-offs in a way that generates useful insights. Thus, a challenge of Agent-Based Modeling is deciding to what extent incorporating real-world data contributes to representing decision-making, and when abstraction or simplification better serves the research question. The following represents a design-based balance between the two.

5.1 Physical and Material Conditions

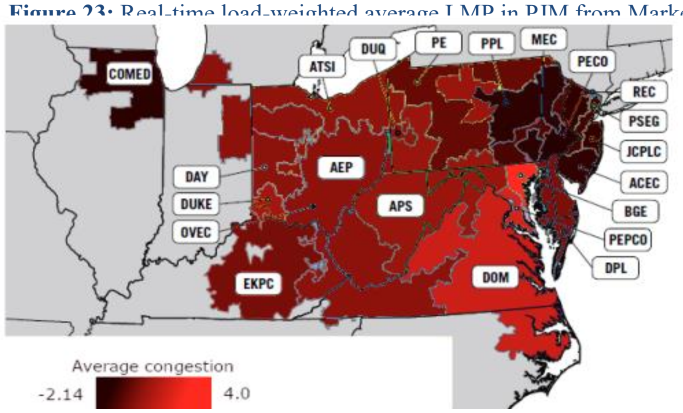
The IAD framework uses the term 'biophysical conditions' which is not directly applicable to network infrastructures. In the vein of Anderies, Janssen, & Schlager (2016), the term "physical and material conditions" is instead used to describe both human-made hard and natural hard infrastructure using Ostrum's framework. Physical and material conditions can be evaluated by determining the relevant goods or services. In this case, access to the transmission grid is the good or service in question. Access to the transmission grid is directly related to the congestion on the grid caused by the physical specifications and operating parameters of the substation and transmission lines on the grid, and existing generation and load on the system, which vary spatially and temporally. At a given point in time, power prices differ across PJM's service territory due to limitations in transmission capacity which can generate transmission bottlenecks. When binding, such constraints force the dispatching of more expensive power generation units located in areas where the capacity to import power is constrained. This phenomenon, referred to as congestion, leads to additional charges for the consumption of power in the concerned areas, and thus to more expensive local electricity prices (Godin, 2020). In PJM, total congestion increased by $685.8 million (64%), from $1,068.6 million in 2023 to $1,754.4 million in 2024 (Market Monitor Report, 2025).

LMP varies widely across PJM's transmission zones, with the highest prices seen in the southeast of the service territory and in small, dense urban areas in the northwest.



In the legend, green represents the system marginal price. Each increment to the right represents five percent of the pricing nodes above system marginal price and each increment to the left represents 25% of the pricing nodes below the system marginal price.

Figure 23: Real-time load-weighted average LMP in PJM from Market



The congestion component of PJM's LMP is a significant contributor to the overall prices differences across the service territory and that PJM experiences a high degree of congestion. (Godin, 2021)(Figure 24)

Figure 24: PJM average congestion component heat map (Godin, 2021)

This congestion can be understood in the context of the type of good/service that access to transmission is in terms of its subtractability and excludability. Subtractability refers to whether one actor's use of a resource diminishes its availability to others. Excludability refers to how easily actors can be prevented from accessing a resource. (Polski, Ostrum, 1999)

Table 13: Characteristics of good types (adapted from Ostrom, 2005)

Difficulty of excluding potential beneficiaries		**Subtractability of Use**	
		Low	*High*
	High	Toll goods	Private goods
	Low	Public goods	Common-pool resources

An uncongested grid with unrestricted headspace at points of interconnection shares characteristics with common-pool resources in that there is high difficulty of exclusion (it is not possible for one generator to exclude another generator from getting connected to the grid) and also by which where is high subtractability (the connection of one generator to the grid lowers the available capacity on grid). However, as shown above, PJM operates within a congested grid, and the interconnection process exhibits characteristics of a private good due to its levels of excludability and subtractability. Under the current system, transmission and headspace at points of interconnection are severely constrained. In theory, excludability is still low—any developer may submit an interconnection request, and PJM is obligated to provide non-discriminatory access. In practice, however, de facto excludability emerges: existing generators already utilize much of the grid's capacity, lowering the threshold above which new generation triggers substantive and expensive network upgrades in order to connect to the grid. Additionally, any new generator contributes to the network upgrade size and costs for others in the same cluster study, creating a barrier to entry for less capitalized or later-stage projects. Subtractability is as high in a congested grid as it is in an uncongested grid. Each additional interconnection that consumes available capacity reduces the remaining headroom and accelerates the need for expensive network upgrades. Subsequent projects face rising costs and longer timelines. Earlier, high-capacity projects can therefore crowd out or delay later entrants, making subtractability both temporal (who arrives first) and spatial (where capacity is most constrained).

In applications of the IAD framework, allowance must be made for the possibility that a particular good or service activity may have the properties of different types of goods under different institutional settings (McGinnis, 2016). This possibility is found true for access to transmission, as the nature of the service changes based on congestion-related infrastructure availability.

The state of transmission today in PJM is due to PJM's transmission planning being largely piecemeal, reactive, and insufficiently regional, resulting in limited headroom and transmission capacity for new generation. The generation interconnection process has effectively become the primary mechanism for network upgrades, placing an inefficient and fragmented economic burden on developers. While the Regional Transmission Expansion Planning (RTEP) process operates on a 15-year horizon, it relies heavily on local plans and does not proactively incorporate generation forecasts, retirements, or electrification trends. Efforts like the 2022 "Grid of the Future Study" introduced forward-looking analysis but have yet to meaningfully shape planning outcomes. RTEP remains siloed across reliability, economic, and public policy categories, with limited use of multi-driver projects and little integration of supplemental projects into a coordinated portfolio. (PJM Regional Planning, 2022)

ABM Application: (Node) Physical and Material Conditions

The experimental design of the ABM includes initializing the characteristics of the Project Agent, Node, and System, and calibrating the relative impact of input factors within functions. Assessing the model initialization against real-world outputs gives confidence in the model's ability to represent key processes.

Data Inputs: Node

The nodes in the model are based on PJM transmission owner regions. PJM is divided into 21 TO regions, each containing between five and two hundred system nodes with distinct LMPs.

For this model, thirteen of PJM's TO regions are represented, each aggregated into a single node within the agent-based model. These thirteen regions were selected because they received generator interconnection requests in TC1, collectively cover the majority of PJM's service territory in terms of existing generation and load, and account for approximately 90% of the current interconnection queue (MW). The thirteen nodes are: DPL, ComEd, AEP, EKPC, PEPCO, Dominion, AEC, ATSI, AMPT, Dayton, PENELEC, APS, and PPL

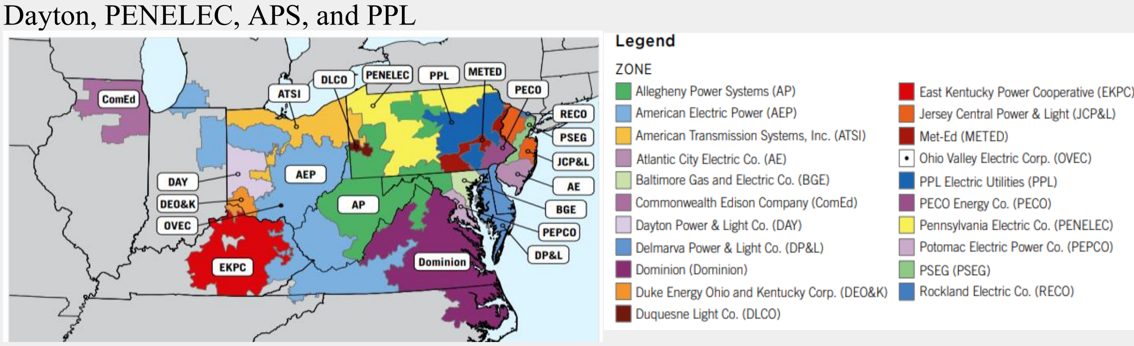


Figure 25: PJM Transmission Owner Regions (PJM Transmission, 2025)

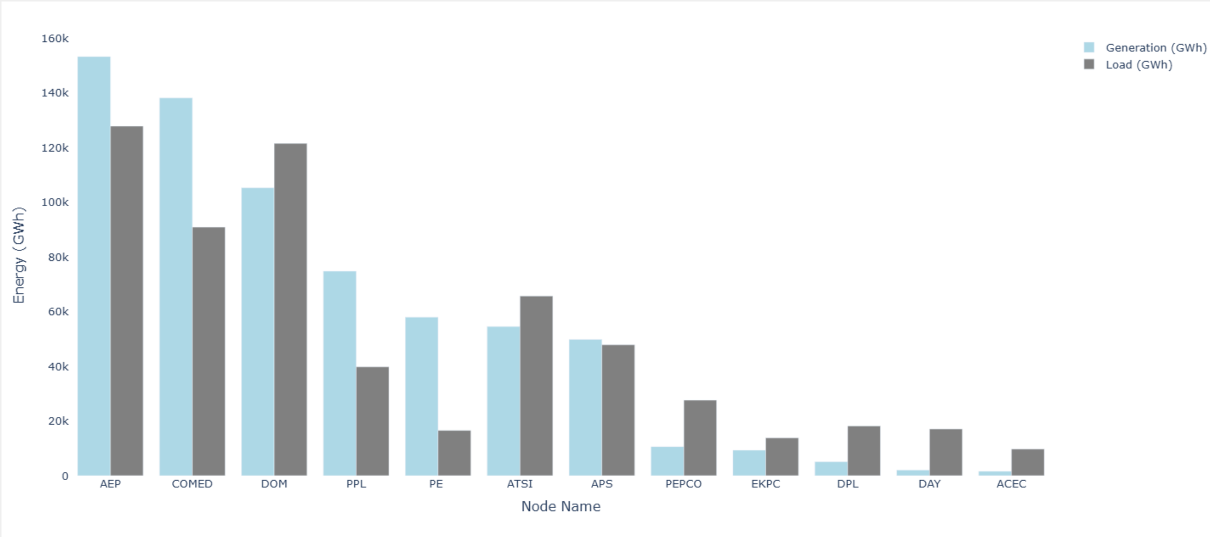


Figure 26: Total Generation and Load (GWh) by Transmission Owner (Data from Market Monitoring Report, 2024)

The 2024 Market Monitoring Report publishes data used as TO zone characteristics that interact with the agents and system in the model.

Table 14: Node Data Inputs

Node States	**Source**
LMP ($/MWh)	Table 3-34 *(MMR, 2024)*
Annual Generation (GWh)	Table 3-63 *(MMR, 2024)*
Annual Load (GWh)	Table 3-63 *(MMR, 2024)*
Installed Generation by Fuel Type (GW)	Table 12-1 *(MMR, 2024)*
Congestion Costs ($M)	Table 11-10 *(MMR, 2024)*
Congestion Indicator (round 0) ($/MW)	=Congestion Costs/Installed Capacity x 1000
Congestion Hours (hours)	Table 3-95 & Table 3-96 *(MMR, 2024)*
Queued Capacity by fuel type (GW)	Table 12-21 *(MMR, 2024)*
Projected Load Growth (%)	*PJM Long-Term Load Forecast Report, 2025*
Available Capacity (round 0)*	10% of installed capacity
MW Threshold 1*	=Available capacity
MW threshold 2*	300% of MW Threshold 1
NU Cost Bin 2*	‘Assigned_Cost’ *PJM TC1 Spreadsheet*

NU Cost Bin 1*	‘Assigned_Cost’ *PJM TC1 Spreadsheet*
NU Cost Bin 0*	‘Assigned_Cost’ *PJM TC1 Spreadsheet*

*These variables operate together in a piecewise function described below

<u>Determining Available Capacity, Network Upgrade Cost Bins, and MW Thresholds</u>
Cost assignment in cluster studies, as outlined in Chapter 4.3, is based on the principle that the more generation projects apply at a node, the more expensive the network upgrades become on a per-megawatt basis. This is because transmission systems have discrete capacity thresholds, and moving from one threshold to the next often requires increasingly complex and costly upgrades. The process can be conceptualized as a piecewise function, where each segment corresponds to a specific upgrade “bin”:
The first bin’s cost is the base interconnection facility. At low project volumes where there is available capacity, the only cost is for the direct interconnection facility needed to connect the project. The second bin represents wider system impacts. Once project capacity at the node exceeds the first threshold, additional network reinforcements are required to manage system-level impacts. The third bin represents affected system impacts. If capacity applications exceed the second threshold, there are costs for impacts on affected systems, the most expensive tier. Each threshold represents a step change in both available capacity and cost per MW, rather than a smooth continuum. As a result, developers connecting early at a node may face relatively low costs, while those applying later may trigger higher-cost thresholds, increasing the overall network upgrade burden per MW. The piecewise function used in this model encodes these thresholds by defining MW Threshold 1 as 50% of the node’s available capacity and setting MW Threshold 2 as 150% of MW Threshold 1 and assigning each bin its corresponding network upgrade cost. Each round, as the available capacity changes based on projects built at each node and transmission built, the MW Thresholds correspondingly change. This approach ensures that cost assignment reflects both timing and scale of interconnection requests, aligning the model with how real-world cluster studies often escalate costs as congestion grows.

$$\mathrm{NUCost} = \begin{cases} \mathrm{NUCost}_0, & \text{if } MW_{\mathrm{tot}} < MW_1, \\ \mathrm{NUCost}_1, & \text{if } MW_1 \leq MW_{\mathrm{tot}} < MW_2, \\ \mathrm{NUCost}_2, & \text{if } MW_{\mathrm{tot}} \geq MW_2 \end{cases}$$

Figure 27: Piecewise Cost Function for Network Upgrade Costs

The lack of available data on available capacity is a fundamental problem in the real-world interconnection queue. Project developers have to make judgements on where available capacity is on the system and often use the process as a cost discovery tool because it is difficult to predict what costs will be. To set values for each node’s piecewise functions, the assigned network upgrade costs and the cumulative size of projects that applied at each node from PJM’s TC1 were used as benchmarks. Additionally, a sampling of contingencies caused by injections of different sizes at buses in each TO Zone was conducted on PJM’s public version of QueueScope under the 2027 RTEP Base Case Summer Peak Scenario. Every bus had at least one contingency with pre-loading conditions of over 100%. This in combination with high network upgrade costs and dropouts confirms a grid with very little headroom available at the NU Cost. (PJM QueueScope, 2025)The starting point of available capacity was thus assumed to be 10% of the initial installed capacity at that node. This is also the value for MW1. MW2=300% MW1 and the network upgrade costs are benchmarked to available data on TC1 data from 100,000-700,000$/MW. These parameters are tested in the sensitivity analysis in Section 7.2.

These physical and material conditions occur not only at the transmission zone level but at the system level and include attributes like installed capacity, LMP, and capacity market clearing prices.
PJM's installed capacity form is around 24.5 GW and consists mostly of fossil fuel generators, a strong contrast to the interconnection queues which are almost entirely renewables and storage resources.

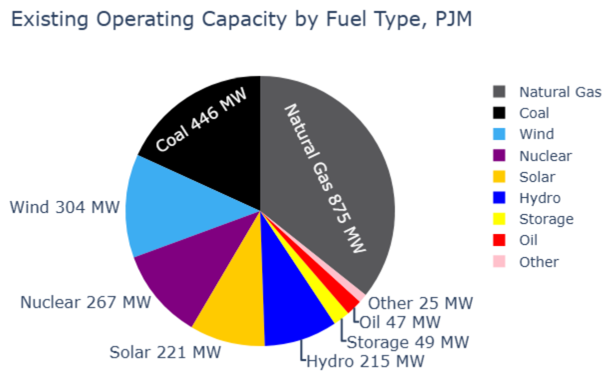


Figure 28: PJM Total Installed Capacity (data from S&P Global, 2025)

Another system condition is the capacity clearing market price, as it represents the balance of load and generation on the system.

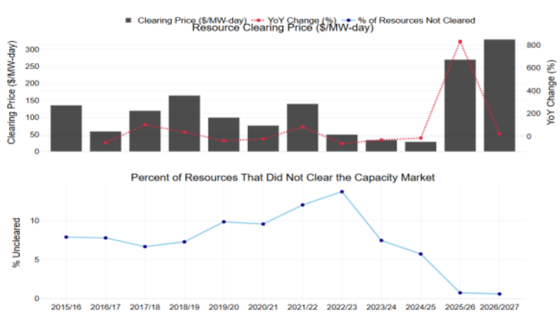


Figure 29: Capacity Market Clearing Price Inputs, Volatility 2015-2027

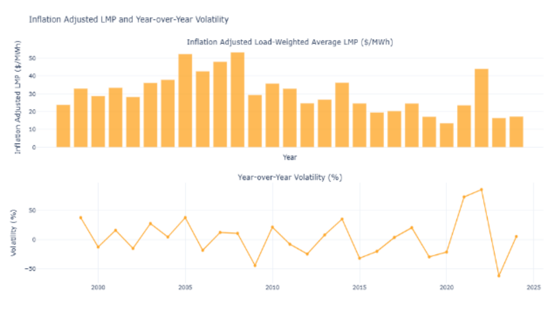


Figure 30: PJM LMP and LMP Volatility 2015-2025

PJM's locational marginal prices (average) are shown in Figure 30. The volatility is shown for reference and understanding that it is less volatile than capacity market prices and that it represents a much higher portion of project revenue (Figure 2).

ABM Application: (System) Physical and Material Conditions

The PJM System level characteristics used in the model are the actual capacity market clearing prices and installed capacity by resource, study and construction timelines, and assigned network upgrade cost references.

Table 15: System Data Inputs

System States	**Value** ***Source***
Installed Capacity	27.1 GW *S&P Global*
Queued Capacity	63 GW *Table 12-21 (MMR, 2024*
Projects with ISAs	46 GW *PJM Ix Factsheet*
Study Timeline	540 days *FERC Order 2023 Compliance*
Construction Timeline	1-7 years *LBNL Queued Up, 2024*
Capacity Market Clearing Prices*	*PJM BRA Auction Report, 2025*
Demand Growth	4.8% per year over the next 10-year period, and 2.9% over the next 20-years *PJM Long-Term Load Forecast Report, 2025*

*Note that the project agents used to seed the model were submitted between July 31, 2018 to October 1, 2020. For simplification it is assumed that these project developers referenced the capacity market clearing prices from 2015/16-2020/21 to inform their decision making.

Physical and Material Conditions: Developers in Transition Cycle 1

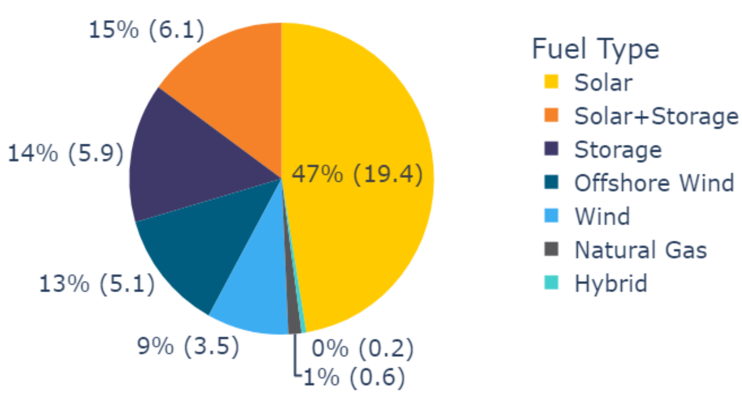


Figure 31: Project Agents by Fuel Types % of total GW and (GW) (from PJM TC1 Phase 1 Projects). There are 315 projects representing 40.8 Gw

Additionally, PJM assigned network upgrade costs and project dropout status data are available for these projects. This data availability allows the model to be calibrated to real world conditions and behavior before instituting reform scenarios. Transition Cycle Interconnection trends in the United States in that it is primarily composed of solar and solar plus storage.

ABM Application: Agent Physical and Material Conditions

Data Inputs: Project Agent

The project agents are a replication of the real-world projects which entered Phase 1 of Transition Cycle 1 in PJM. These projects represent recent developer trends including project size, fuel types, and selected locations and service types. resources. Transition Cycle 2 (TC2) has begun in PJM but cost estimates have not yet been assigned to the projects. The fuel type composition of the TC2 project was observed to be similar to that of TC1, confirming that TC1 is an appropriate batch of projects to use as project agents. For the purposes of the model, it is assumed that each project is developed by a unique project developer.

Table 16: Data Input Project Agent

Agent States	**Value** ***Source***
Developer	‘Project_ID’ *(PJM TC1 Spreadsheet)*
Fuel Type	‘Fuel_Type’ *(PJM TC1 Spreadsheet)*
Size	‘Megawatts_Energy’ *(PJM TC1 Spreadsheet)*
Transmission Owner	‘Transmission_Owner’ *(PJM TC1 Spreadsheet)*
Study Time	590 days (max) 390 days (min) *FERC Order 2023 Compliance Ruling*
Risk Tolerance	Random number between 0.85 and 1.2 =ROUND(0.85 + (1.2 - 0.85) * RAND(), 2)
Dropout Threshold*	=‘atb_capex’* ‘atb_multiplier’* ‘risk_tolerance’ *NREL ATB 2024*

*Dropout threshold is a Project Agent State value. If their assigned network upgrades are above the dropout threshold, they will dropout, and under the threshold they will remain in. This value is determined by whether the network upgrades are more than 30% of their total capital expenditures. The project’s total estimated capital expenditure is from NREL ATB 2024 data. Incorporating a stochastic variable ‘Risk_tolerance’ allows different developers to behave differently.

Now that the data inputs have been established for each level of the model and model functions explained, reform scenarios are developed for the model experimentation.

5.2 Developing Reform Scenarios

This section applies the institutional analysis from Chapter 3 and the developer incentive assessment from Chapter 4 to develop reform scenarios for implementation in the agent-based model. The aim of this chapter is to begin addressing Subquestion 4:

How could targeted reforms shift developer behavior and improve interconnection outcomes in PJM?

The reforms developed in service of this subquestion are framed as interventions targeting key outcomes of the interconnection action situation. The primary target is to increase ERIS adoption within PJM, thereby reducing system-wide interconnection timelines and accelerating renewable energy deployment. Section 5.2.1 examines ERIS adoption in other RTOs to identify rule-based drivers of variation. Section 5.2.2 compiles reform proposals from policymakers, advocacy groups, and government agencies, categorizing them within the action-situation framework. Section 5.2.3 selects two reforms for detailed analysis, explains their selection, and outlines their expected effects at both the project and system levels.

5.2.1 Variation in U.S. Regions

Under FERC Order 2003, RTOs must allow developers to choose between ERIS or NRIS agreements. ERIS adoption has remained low across the United States. However, this outcome is not uniformly low. Table 17 demonstrates that active capacity varies from <1% (PJM) to 23% (Southeast, Non-ISO region). To understand these differences in ERIS and NRIS selection patterns, this section examines how different regions evaluate and administer the ERIS/NRIS differences in the generator interconnection process, the transparency of those differences, and any driving exogenous factors or differences in the rules-in-use.

Table 17: Active Capacity by Service Type Across U.S. Regions (Data from LBNL Queued Up, 2024)

	% of Active Capacity		% of Queued Capacity
Region	ERIS	NRIS	ERIS
PJM	<1%	100%	1%
MISO	4%	96%	5%
CAISO	12%	88%	10%
ISO-NE	16%	84%	5%
West*	18%	82%	-
Southeast*	23%	77%	-
SPP	-	-	32%

*non-ISO

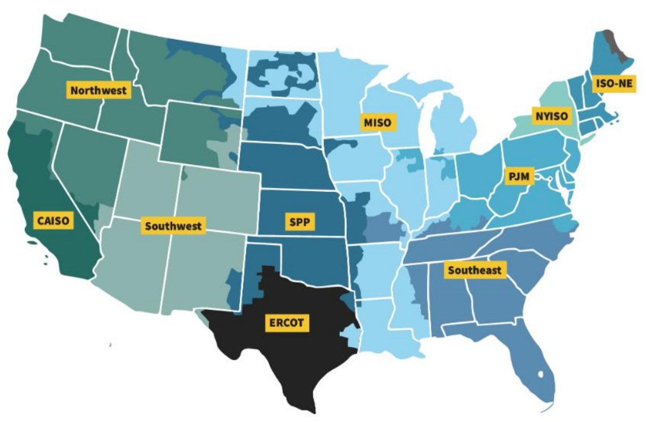


Figure 32: U.S. Electric Regions (FERC RTOs and ISOs, 2025)

ERCOT, while outside FERC jurisdiction, provides a reference point for a less restrictive ERIS approach. It operates an "energy-only" market where real-time prices signal scarcity and drive investment, also known as "connect and manage." where 100% of active capacity is ERIS. For FERC-jurisdictional RTOs and non-ISO providers, the treatment of ERIS differs significantly. (Norris, 2024) categorized these differences by study methodology and cost allocation practices, considering parameters such as assumed generator dispatch, load and generation cases, contingency categories (TPL-001), mitigation options, and thresholds for assigning network upgrade costs to ERIS generators. (Norris, 2024)

Variations in Study methodology and Cost allocation methodology (Aggregation Rules-in-use)

Norris considered the following study parameters to categorize the restrictiveness of different RTO's treatment of ERIS: Generator Dispatch (the assumed dispatch level for the ERIS generator), load and generation cases, contingency categories (which TPL-001 contingency categories are applied to ERIS generators), mitigation options (when is redispatch or alternative mitigation considered to address and injection constraint), what level of system impact triggers cost allocation for ERIS generators, and which network upgrade costs are allocated to ERIS generators. Norris came to the conclusions represented in Figure 33.

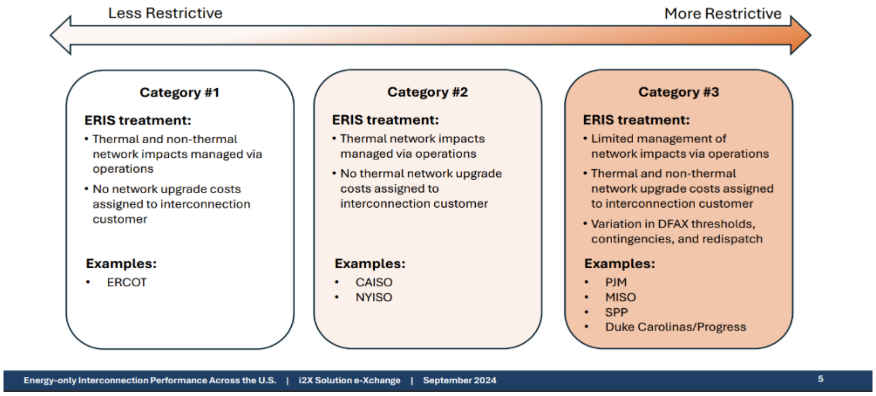


Figure 33: Spectrum of ERIS Treatment, from i2X Solution e-Xchange, 2024

MISO studies ERIS under most TPL-001 contingency categories and now requires ERIS generators to pay for identified network upgrades if their DFAX is ≥10% under contingency conditions (or ≥5% under system intact). PJM studies ERIS agreements under nearly all contingency categories, except single contingencies. SPP also applies most contingency categories to ERIS.

CAISO and NYISO assume that real-time congestion management via redispatch can effectively address all thermal power flow constraints for ERIS generators, provided the ISO secures the transmission facility. In the context of deliverability studies, this means ERIS generators are turned off (i.e., assumed to not dispatch). Concerning non-thermal reliability impacts, where they arise for ERIS generators, breaker replacements may be necessary; CAISO has also used remedial action schemes (RAS) for non-thermal reliability impacts, limited interconnection cost data is currently available to assess the impact of this study approach in CAISO and NYISO for assigned network upgrade costs.

This stringency categorization helps to explain the low ERIS penetration in PJM and MISO and slightly higher but still low adoption in CAISO, but does not explain the 32% of SPP's current queue electing ERIS. Part of this might be explained by the fact that SPP studies projects for ERIS by default and that SPP does not have a capacity market (SPP, 2017).

Capacity Market Variation (Payoff Rules-in-use)

Investment in generation resources is essential for maintaining reliability in electricity systems. However, wholesale energy prices alone rarely provide sufficient incentives to achieve the efficient quantity and mix of generation capacity (Joskow, 2008). PJM, MISO, NYISO, and ISO-NE all operate capacity markets, where most of the required capacity is procured through these markets rather than via bilateral contracting (GAO, 2017). In contrast, CAISO, SPP, and non-ISO regions use different approaches to resource adequacy procurement. ERCOT does not operate a capacity market; instead, it relies on an energy-only market with scarcity pricing.

Scarcity pricing refers to the practice of raising energy prices above the marginal cost of the last unit dispatched during periods of limited generation capacity. The presence of a substantial revenue stream from capacity market participation serves as a strong incentive for developers when choosing between ERIS and NRIS agreements. This helps explain the high proportion of queued ERIS projects in SPP, where ERIS treatment is strict, but no capacity market exists to provide additional revenue opportunities.

5.2.2 Solution Space and Reform Scenario Selection

Reports such as *Unlocking America's Energy* (Grid Strategies and The Brattle Group, 2024), *Generator Interconnection Scorecard* (AEU, Grid Strategies, The Brattle Group, 2024) work from the i2X Solution e-Xchange, the DOE's Transmission Interconnection Roadmap, and comments from RMI and Tyler Noris on FERC's Innovations and Efficiencies in Generator Interconnection workshop, provide categories and detail of interconnection reforms to do with ERIS and NRIS agreements. These ideas paired with the understanding of the PJM interconnection process developed in Chapters 3 and 4 result in the following categories of reforms to improve ERIS adoption.

1. Differentiate ERIS and NRIS Study Methodology

Transmission providers should update interconnection study methodologies to reflect the distinct characteristics of ERIS and NRIS agreements. Current models often omit consideration of market-based congestion management, leading to the identification of distant reliability violations that rarely occur in practice (Gramlich, 2024, Reform 3A.2). For ERIS agreements, redispatching can typically resolve most thermal power flow constraints, yet prevailing assumptions attribute network upgrade responsibilities to ERIS generators based on steady-state studies (Norris, 2024a, at 13). Studies should therefore test only contingencies relevant to ERIS, including the ability to curtail ERIS resources. Clear differentiation in study standards and associated cost obligations between ERIS and NRIS agreements would better reflect their distinct roles and reduce unnecessary costs for ERIS projects.

2. Differentiate ERIS and NRIS Cost Responsibilities

Network upgrades should be triggered solely by the service level requested. Present interconnection practices frequently mandate upgrades that are avoidable under real-time grid management, such as market-based generation redispatch. Aligning upgrade requirements with requested service levels, and offering developers a non-firm, energy-only option, can relieve interconnection customers and ultimately electricity consumers of unnecessary costs. Such reforms also support more efficient integration of new generation resources.

3. Enable Upgrading from ERIS to NRIS

Maintaining the option to upgrade from ERIS (non-capacity designation) to NRIS (capacity designation) preserves valuable flexibility and option value. This pathway enables faster expansion of firm capacity when system conditions demand it, benefiting both grid operators and developers. Removing or restricting this upgrade option risks diminishing ERIS's appeal and limiting its contribution to overall grid flexibility.

4. ERIS Fast Track

Fast-track processes should prioritize the most-ready interconnection requests for available headroom. Transmission providers should identify zones with available or anticipated capacity to guide developers, particularly ERIS generators, who prioritize less stringent deliverability requirements. Given projected retirements of over 100 GW of existing generating resources over the next decade, fast-track procedures can significantly reduce interconnection timelines by allowing requests that utilize existing and planned grid capacity to proceed without triggering extensive network upgrades. Projects passing minimal adverse impact screening can advance directly to the interconnection agreement phase, while those with material impacts proceed through the full cluster study process. Implementing scoring or prioritization methods for readiness ensures equitable access to limited capacity and aligns project timelines with grid needs.

5. Address Information Asymmetries

5a. Availability of Capacity

Transmission providers should provide developers with accurate, up-to-date maps of available capacity, including anticipated capacity from retiring plants or planned infrastructure. While thermal capacity data is increasingly accessible, non-thermal constraints remain opaque. Uncertainty arises from challenges in attributing shared network costs, limitations in replicating transmission models, and the role of engineering judgment, all of which can be reasonable but unpredictable. Reducing these uncertainties can lower new generation costs and delivered energy costs for consumers. Information barriers are limiting the effectiveness of interconnection policy. If developers do not have a good understanding of hosting capacity, they are not able to target their efforts to uncongested areas, or size projects relative to the amount of available capacity (Waiting in Queue: A Historical Evaluation of Interconnection Policy June 2023 Daniel S Boff Sarah Barrows Title). Industry stakeholders are increasing realizing that well-executed hosting capacity analyses are essential to the project development process (IREC. 2017. Optimizing the Grid: Regulator's Guide to Hosting Capacity Analyses for Distributed Energy Resources. Interstate Renewable Energy Council).

5b. Cost Clarity

Interconnection customers report greater concern regarding uncertainty about total costs than the average cost levels themselves. Cost clarity throughout the interconnection process is therefore critical to fostering developer confidence and supporting efficient project planning.

5c. Clarify and Confirm Curtailment Procedures for ERIS Generators

Developer uncertainty can be further reduced by formally confirming that all generators, regardless of interconnection service type, are dispatched based on economic merit in real-time operations. Evidence indicates that RTOs and ISOs often do not distinguish between ERIS and NRIS generators when prioritizing curtailment for congestion or emergencies. Codifying these procedures would improve transparency and increase developer confidence in ERIS.

5d. Post-Agreement Construction Monitoring

Construction schedules for network upgrades are often lengthy and unpredictable. Delays stem from external factors, such as supply chain bottlenecks and land rights, and internal factors, including transmission owner budget and management constraints. Requiring tracking of construction progress and providing transparent information about available headroom and infrastructure at interconnection points can reduce financing costs and expedite project completion, ultimately lowering consumer costs.

6. Decouple Interconnection from Network Upgrade Investments
Consistent with the DOE's Transmission Interconnection Roadmap (Solution 3.3), interconnection reforms should delink the process from extensive network upgrades, particularly large regional "deep" upgrades. Mechanisms such as fixed entry fees, rather than variable upgrade costs, can improve upfront cost certainty, reduce financial risk, and enhance overall interconnection efficiency. Encouraging proactive regional planning processes to better integrate interconnection needs and reduce duplication or inefficient cluster study approaches

ABM Application: Selected Reform Scenarios

From the solution space two primary reform scenarios were developed based on anticipated ERIS adoption effectiveness and ability to be implemented in the model logically. The details of the implementation and hypothesis for outcomes are discussed in Chapter 8.
Reform Scenario 1: Study and Cost Differentiation (combines suggestion 1&2). This will be implemented via a ERIS_NU_Factor and ERIS_Study_Factor and ERIS_Differentiation
Reform Scenario 2: Infrastructure Investment with Capacity Market Ceiling. This will be implemented via changing the Transmission_Magnitude and Transmission_node_number as well as capacity ceiling.

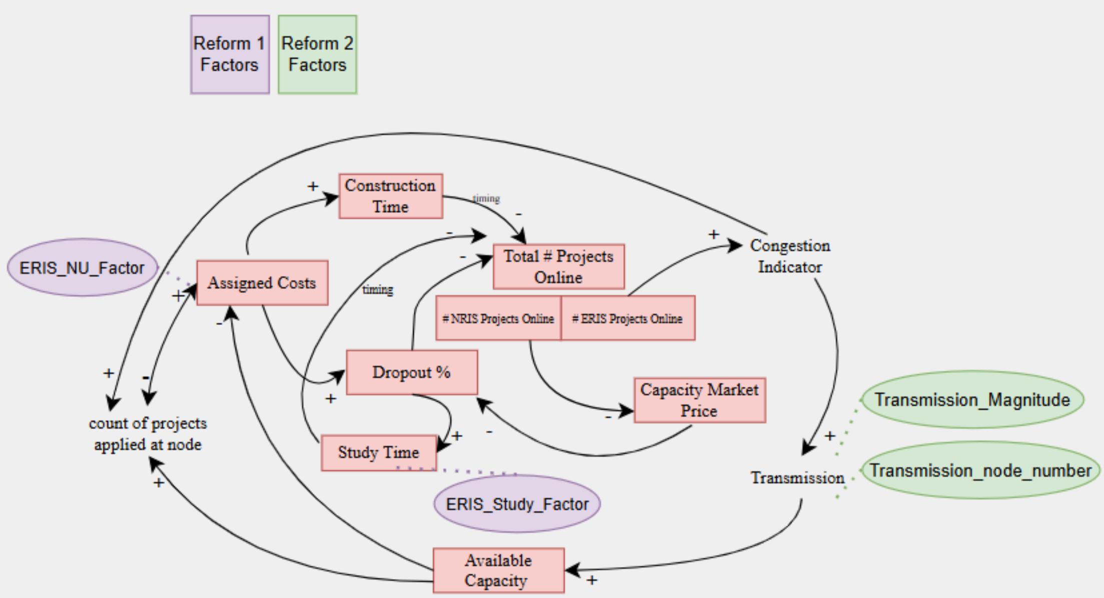


Figure 34: Causal Loop Diagram of ABM with Outcomes

Chapter 6. Software Implementation

The following section provides the structure and pseudo code for key processes in the ABM and a description of how the model is run for experimentation.

6.1 Structure and Pseudo Code for Key Processes

Pseudocode is a way of writing code that does not rely on a particular syntax or programming language. A pseudocode is a step-by-step description of an algorithm in code-like structure using layman's terms for readability. The following key processes are written out in Pseudocode: selecting location, selecting NRIS versus ERIS, assigning NU costs, dropping out, assigning study time, building transmission.

<u>Choosing Node</u>

Choosing node is a project agent level-based decision that begins with a node eligibility screening and then proceeds to a rank-based weighting with a stochastic element. Project agents will not choose a node where they dropped out in the last three rounds, this eliminates from zero to three nodes from their considered nodes.

```
N = 3
for each project_agent
for each of the last N rounds:
if project_agent dropped out at node:
remove node from valid_nodes
```

Next the project agents gather information about the remaining nodes and weights are assigned to these values. Project agents favor nodes with high LMPs, available capacity, large generation output, low congestion, and low network upgrade costs last round. Wind and solar project agents favor nodes with other solar or wind developers. A random adder is included to encapsulate variation in developer nodal preferences not explained by given node characteristics.

```
 for each project_agent
        for node in valid_nodes:
        lmp_score = lmp_ranks[node]
        queue_score = queue_ranks[node]
        nu_score = nu_cost_ranks.get(node, default_max_rank)
        size_score = size_ranks.get(node, default_max_rank)
        if fuel_type in ["solar", "solar_storage"]:
       fuel_bias = node.percent_solar
      else if fuel_type == "wind":
      fuel_bias = node.percent_wind
     else:
        fuel_bias = 0
        random_adder = random number between -1 and 1
        node_score = -1 * (size_score + lmp_score + queue_score + fuel_bias + nu_score +
random_adder)
      store (node, score)
```

Finally, the project agent selects at random one of the top three scored nodes to apply to:

```
  scored_nodes = sort nodes by node_score (highest first)
  top_choices = top 3 nodes from scored_nodes
```

chosen_node = random choice from top_choices

Choosing Service Type

Choosing node is a project agent level-based decision that occurs only in the first round of each project agent's time in the model, after the agent has selected a node to apply to. The base probability of a project selecting ERIS is the same across the system and depends on if the PJM studies ERIS faster (lower ERIS study factor) and assigns less expensive network upgrades (lower ERIS NU Factor).

```
For each project_agent
    if internal_step_count == 0:
        base_prob_eris = ((1 - self.ERIS_study_factor) + (1 - self.ERIS_NU_factor)) / 2
```

Next, if the developer's differentiate ERIS from NRIS agreements in their decision making, the probability of each project_agent selecting agent is adjusted by its fuel type and a free ride factor is assigned based on the number of NRIS projects added.

```
if ERIS_differentiation=TRUE
        free_ride_factor = min(total_nris / 20, 1)
        if fuel_type=="storage", "solar_storage"
            fuel_factor=.1
        if fuel_type=="solar", wind
            fuel_factor=.05
else:
        free_ride_factor=0
        fuel_factor=0
eris_prob = base_prob_eris + free_ride_factor+fuel_factor
```

Finally if the eris_prob is greater than a random number between 0 and 1, the service type is ERIS, otherwise it is NRIS.

```
service_type = 'ERIS' if random.random() < eris_prob else 'NRIS'
```

Assigning Network Upgrade Costs

Network upgrade costs are assigned via a node-specific piecewise cost function that is dependent on the total MW that applied to that node that round.

$$\text{NUCost} = \begin{cases} \text{NUCost}_0, & \text{if } MW_{\text{tot}} < MW_1, \\ \text{NUCost}_1, & \text{if } MW_1 \leq MW_{\text{tot}} < MW_2, \\ \text{NUCost}_2, & \text{if } MW_{\text{tot}} \geq MW_2 \end{cases}$$

If ERIS differentiation is occurring, then the piecewise function will only apply to the MW of NRIS that applied at that node, and ERIS will be assigned the lowest NU Cost threshold.

$$\mathrm{NUCost} = \begin{cases} \mathrm{NUCost}_0, & \text{if project is ERIS}, \\ \mathrm{NUCost}_0, & \text{if } MW_{\mathrm{NRIS}} < MW_1, \\ \mathrm{NUCost}_1, & \text{if } MW_1 \leq MW_{\mathrm{NRIS}} < MW_2, \\ \mathrm{NUCost}_2, & \text{if } MW_{\mathrm{NRIS}} \geq MW_2 \end{cases}$$

Dropping Out

Project_agents dropout as assigned network upgrade costs increase. Projects compare their assigned network upgrade costs to their fuel type project capital expenditures multiplied by their risk tolerance and capital expenditure multiplier. NRIS projects have a higher threshold for dropping out since they also receive capacity market revenue.

```
if service_type = "ERIS"
  if assigned_cost > CAPEX* CAPEX_multiplier * risk_tolerance:
        dropped_out = True
if service_type = "NRIS"
  capacity_market_revenue_factor=(average capacity_price last five rounds)*ELCC*365
 if assigned_cost > (CAPEX* CAPEX_multiplier * risk_tolerance)+capacity_market_revenue_factor
        dropped_out = True
```

Assigning Study Time

Study time is assigned at the system level and is the same for all projects of the same service type, since projects are studied in one cluster. For NRIS projects, the assigned study time starts at one round. If more than 40% of projects drop out then the cluster needs to be restudied and the study time becomes two rounds. Study time for ERIS agreements are NRIS study time multiplied by the ERIS study factor (a value between 0 and 1).

```
if dropped_out_projects/total_projects > 0.4:
    self.reassign_costs()
    resstudy_factor=1
study_time = 1+restudy_factor
if service_type=”ERIS”
study_time=study_time*self.ERIS_study_factor
```

Assigning Construction Time

Construction time is a function of the cost of assigned network upgrades and incorporates node specific construction delay factors representing variation in permitting timelines in different nodes to a maximum of seven years.

```
construction_time = min(.assigned_cost / 1000 + delay_factor, 7)
```

Building Transmission

Transmission is selected to be built at the end of each round. The system builds transmission at a specified number of nodes to be built at a certain speed. Once the transmission is built, the selected nodes will have increased capacity at the magnitude specified and decreased congestion. Congestion and available capacity update each round based on the projects built at that node.

```
N=3
delay=transmission_speed
If node.congestion is in top N of nodes
        Add node to top_nodes
if current_step>delay
if node in top_nodes
node.congestion_indicator -= 1
   node.available_capacity +=transmission_magnitude
```

<u>Updating Capacity Market Clearing Price</u>

The capacity market price updates every round. During the first round, capacity price is the 329 from 2026/2027 auction, the capacity market price increases if the NRIS projects brought online is less than the expected load growth and decreases if the opposite is true. The price is capped at $329.17, as it is in reality.

```
new_online_mw=NRIS newly online this round
previous_price= self.capacity_prices[-1]
if project_agent=online and project_agent.service_type="NRIS":
   new_online_mw += Project_agent.size*ELCC
if new_online_mw+total_installed_capacity_NRIS<expected_load:
   new_price = 329.17
 else
   new_price=previous_price-(.0765)(new_online_mw)
new_price = min(new_price, 329.17)
self.capacity_prices.append(new_price)
```

6.2 Summary

Chapter 5 and 6 develop an Agent-Based Model (ABM) to explore how PJM project developers choose between ERIS and NRIS agreements under varying policy, market, and system conditions. The model represents the developers as agents making decisions project location, service type, and whether to proceed based on network upgrade costs and responding to interactions with other agents, nodes, and the system. Nodes hosts projects, dispatch generation within node economically, and signal congestion, while the system (PJM RTO) studies interconnection requests, assigns network upgrade costs, builds transmission, and operates the capacity market.

Using real-world data on project characteristics, locational marginal prices, network upgrade costs, and capacity market outcomes, the ABM simulates the full interconnection process in discrete rounds. It captures interactions among developers, nodes, and PJM to evaluate service selection, dropout rates, project completion, and system-level outcomes. This framework provides a platform for testing targeted reforms and understanding their potential impacts on ERIS adoption, interconnection efficiency, and overall system reliability. Chapter 7 builds on this framework to run the model to simulate current system conditions and run analysis on the outcomes

Chapter 7 ABM Experimentation and Analysis

The model is built in Python using the MESA modeling package. Inputs for Node and Agent States are imported from excel files. A datacollector is run during the model to track outputs. All files are stored a Github Repository: https://github.com/abigailweeks-rmi/Thesis.git

To understand how the model is functioning after the model is run, outputs are collected and visualized. Key model outputs happen at system level. In the base case scenario Section 7.1, these outputs are compared to real results in PJM to make sure the model is calibrated to the standard system. Then a one factor at a time analysis is run in Section 7.2 to see the sensitivity of the model to specific inputs and assumptions. The key model outputs are shown in Table 18.

Table 18: System Level Outputs

Output	Variable		Per Round or Cumulative?
Number and magnitude of projects that entered queue, dropped out, are pending*	num_total dropped_out_count dropped_out_count_eris dropped_out_count_nris pending_count pending_eris_count pending_nris_count online_count online_eris_count online_nris_count	total_mw total_dropped_out_mwdr opped_out_eris_mw dropped_out_nris_mw total_pending_mw pending_eris_mw pending_nris_mw total_online_mw online_eris_mw online_nris_mw	cumulative
Capacity Price	capacity_price		per round
System Marginal Energy Price	system_marginal_energy_cost		per round
Where transmission was built this round	transmission_built_this_round[]		per round
Installed Capacity*	total_installed_capacity		cumulative
Available Capacity*	availble_capacity		per round
Network Upgrade Costs*	assigned_costs		per round

*Each of these variables can also be determined at the nodal level for further inspection.

Additionally theMW_threshold_1 andMW_threshold_2 change at each node round if available capacity gets used at that node. These threshold values are not tracked as a system level output but will be examined in the reform scenario analysis.

7.1 Base Case Scenario

The base case is to represent PJM system processes and interactions as they exist now.
In light of the characteristics of the parameters, the nominal values for the identified uncertain model parameters are determined by conducting several one factor at a time simulation runs over wide ranges presented in Table 19. Having the conformity to the scenario goals and taking real world conditions into consideration, the nominal values below are assigned for the base model.

Table 19**:** Baseline Model Nominal Values of Adjustable Parameters

Model Parameter	Value	Range	Unit	Selected Value Meaning
ERIS_differentiation	FALSE	TRUE/FALSE	-	ERIS and NRIS projects are studied in the same cluster and contribute to node MW thresholds together. The dropouts of both service types contribute to each service type's restudy requirements.
ERIS_study_factor	1	[0,1;.05]	-	NRIS and ERIS are studied together and assigned the same study times
ERIS_NU_factor	.8	[0,1;.05]	-	ERIS are allocated 80% of NRIS NU costs
Transmission_build_speed	5	[2-20]	round	Transmission infrastructure takes 10 years to come online
Transmission_magnitude	500	[500-5000]	MW	Each transmission infrastructure increases capacity 500MW
Transmission_node_number	3	[1-21]	#	Transmission is planned for the three most congested nodes at a time
Capacity Price Round 0	329.17	[0-329.17]	$/MW-day	NRIS resources receive $329.17/MW-day for their generation capacity.
Capacity Price Ceiling	329.17	0-Inf	$/MW-day	The capacity market cannot clear higher than $329.17/MW-day

A batch run of the baseline scenario of the model was run over twenty time steps, representing 20 rounds of interconnection. One hundred runs were conducted and the key parameters visualized, to understand the stability of the model when no parameters were adjusted.

The results for GW added each step and percent of projects which dropped out each step compared to PJM historic data are portrayed in Figure 35. First, the GW that came online each model step was found to be quite stable, with a mean of 1.64 GW/year and standard deviation of .31. This is within range of the PJM historic serial data set that in the last decade had average addition of 2.21 GW/year, and noting that the early years of the model have very low GW/year added since the model starts with zero projects in the queue, in reality, projects exist every year in PJM in the construction queue. In the batch run of the baseline scenario mode, the GW added per step surges until around round five, after which the number of projects coming online decreases, a lagging response to the increase in dropouts after round two. The lines on the graph represent PJM average data between 2018 and 2025. The percentage of projects that dropped out each round was 80.73% with a standard deviation of .92%. In comparison the historic queue dropout rate in PJM is around 80.1%.

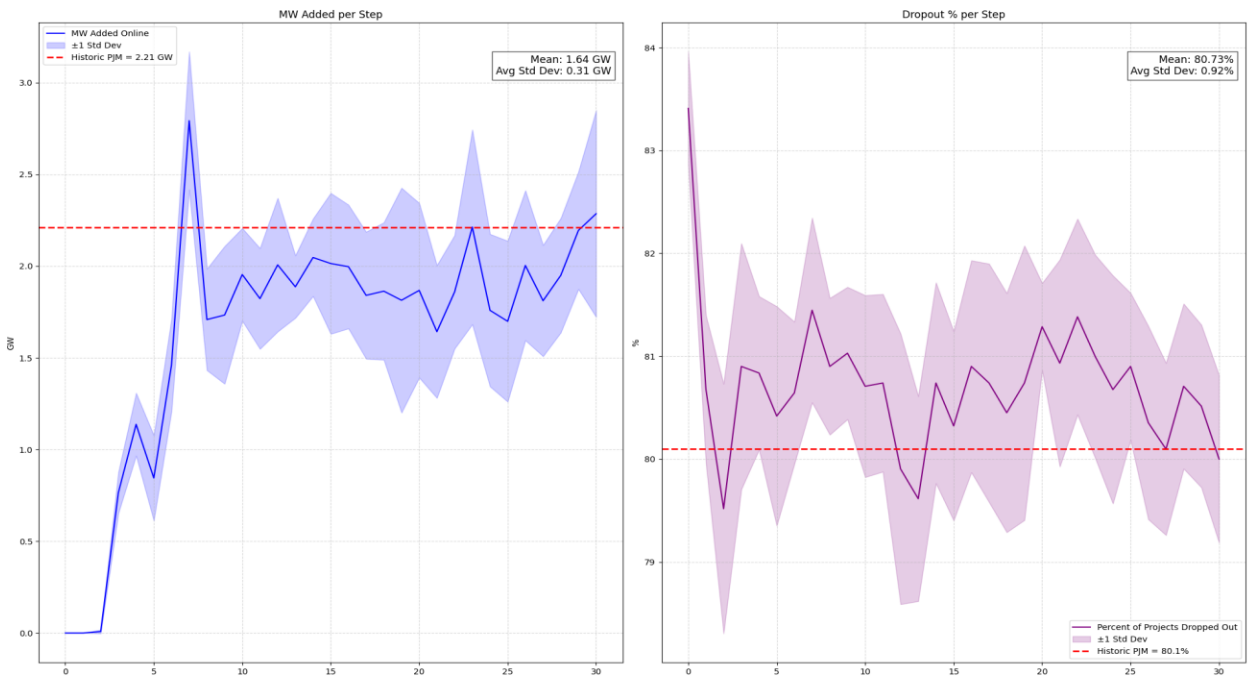


Figure 35: Range of Baseline Model Results per round: GW Added and Dropout %

Next the preference of developers in service type was compared over steps and between model runs (Figure 36) In the baseline model the average percentage of developers by MW that choose ERIS agreements is 5.08% with a standard deviation of 1.49%. This is compared to PJM's whose most recent queue cycles have 4.3% of the developer MWs choosing ERIS agreements.

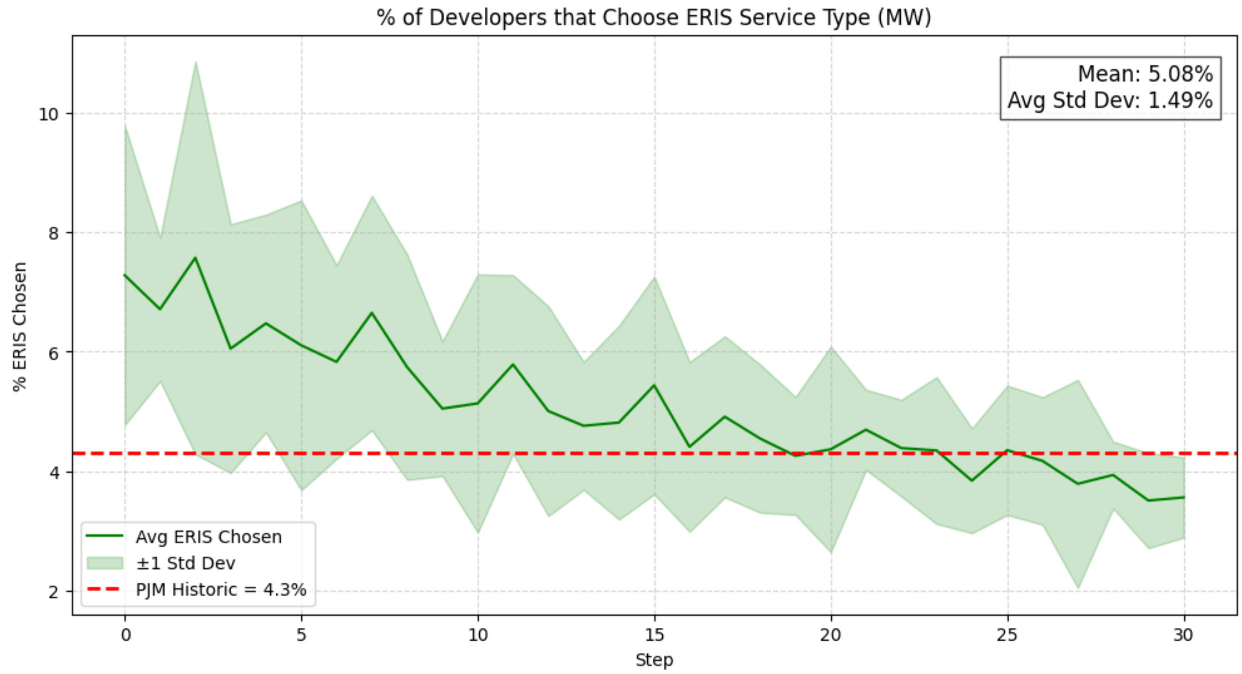


Figure 36: Range of Baseline Model Results per round: GW Added and Dropout % (PJM Historic from PJM Serial Service Status, 2025)

Next the distribution of nodes selected was compared to PJM queued data. The baseline model aligns with what the top three most frequently selected transmission zones are for queued projects: AEP, COMED and DOM. It also is off only one rank for APS, placing ATSI one spot more favored. The model's chosen node function takes into account a variety of factors, including the developer's own past successes. It closely aligns with historic PJM queue selections, enough so to move forward with the model, especially since projects currently queued in PJM Data entered under grid conditions that look different than those the baseline model uses for its assumptions, such as different transmission zone generation profiles and congestion.

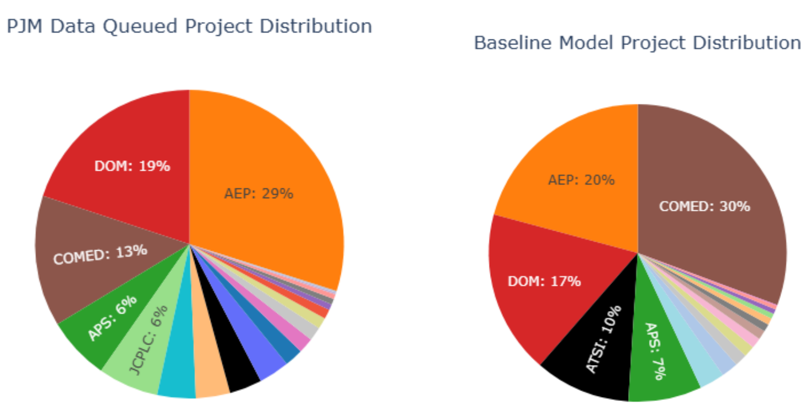


Figure 37: PJM vs Baseline Model Project Distribution (PJM Data from PJM Cycle Service Status, 2025)

Finally, the amount of time it takes from developers applying to enter the queue to getting online is evaluated. The average distribution of the baseline model batch run is shown in Figure 38, with the gray range representing typical PJM historic queue times. The majority of baseline model projects fall into this range which is a function of the study time and construction time adding to between 3-6.5 years.

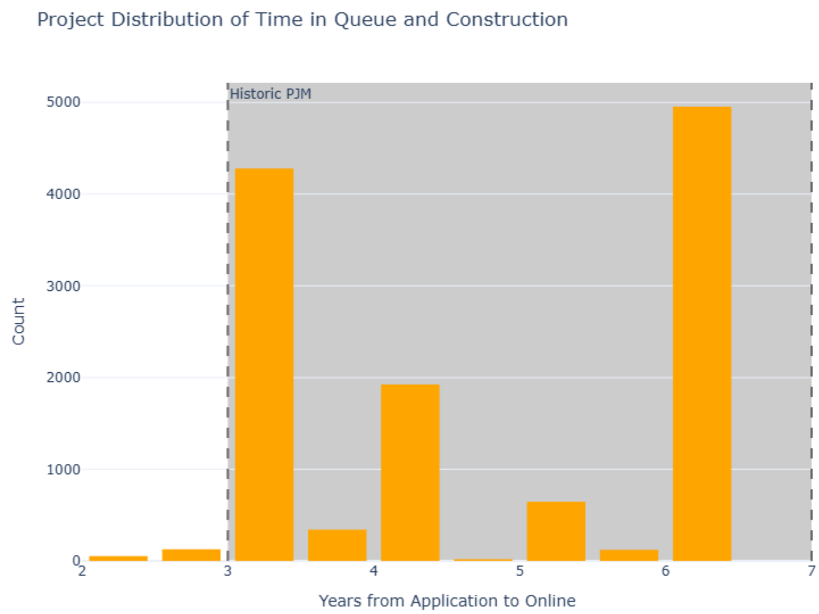


Figure 38: Baseline Model results, time from application to in service (PJM Data from PJM Serial Service Status, 2025)

From this section, it is determined that the output values are sufficiently approximating real-world results to move into the next phase of ABM experimentation. While these results are representative of reality, to ensure that the model represents the system's functioning under a wide range of conditions, it is crucial to demonstrate that the logic is robust to parameter variation. Having assigned the nominal values of the base model for the uncertain parameters, in the following chapter, sensitivity analysis will be conducted to ensure the current setting of the base model gives results that are robust and free from biases due to modelling choices made in the model conceptualization.

7.2 Sensitivity Analysis Results and Discussion

Understanding the dynamics of ABMs can be challenging due to their inherent complexity. Sensitivity analysis is a valuable method for this purpose, as it reveals how changes in model parameters influence outcomes, thereby offering insights into the underlying mechanisms of the model. (CREM, 2018) A range of assumptions translates into a range of parameter values, which in turn produce specific model results. For these insights to be credible, they must not rely on a narrow or uncertain set of assumptions; it is therefore essential to demonstrate that findings remain robust across a range of parameter variations. This is particularly important when the model seeks to explain phenomena that occur under diverse real-world conditions. The primary aim of sensitivity analysis is to assess how variations in model parameters affect outputs. Once validated in this way, the baseline model serves as a reference point against which new hypotheses, interventions, or policy changes can be tested, contributing to an iterative process of knowledge building. A common method, one-factor-at-a-time (OFAT) sensitivity analysis, involves selecting nominal parameter values and varying one parameter while keeping others constant. This local approach identifies how outputs respond to individual parameter changes, revealing whether relationships are linear or non-linear, and whether tipping points exist where small parameter shifts lead to significant output changes (Guus, 2016)(Arika, 2014). Such analysis helps uncover key model mechanisms. Typically, outputs are plotted after systematically varying each parameter over a defined range. Parameters selected were those with uncertain or unverified values, or those identified during model conceptualization as having potentially significant influence on results. Table 18 summarizes the parameters, their nominal values, and the ranges used for variation. Nominal values were determined through preliminary trials during baseline model development. The upcoming sensitivity analysis will test whether these values produce stable and robust outcomes suitable for baseline use. A model is considered robust with respect to a parameter when its key outputs and behaviors remain largely unchanged despite variations in that parameter being context dependent. As the main outputs of the simulation model, the percentage of projects that are ERIS agreements and the MW of ERIS and NRIS agreements added each time step are monitored as the parameters are varied.

7.2.1 ERIS Study factor

A series of experiments was conducted to investigate the impact of the study factor on the adoption of ERIS agreements to the grid. The experiments were conducted from 0-1 with increments of .05. The results demonstrated that the ERIS adoption, as MW ERIS and MW ERIS/MW total, is sensitive to the assigned threshold values (Figure 39). In all of these sensitivity analyses, the parameter ERIS Differentiation is left as false, as it is in the baseline model. As the model progresses, no matter the ERIS study factor, more ERIS agreements come online. However, as the ERIS Study Factor increases (becoming closer to the same as the NRIS Study time assigned), the end amount of ERIS agreements only decreases.

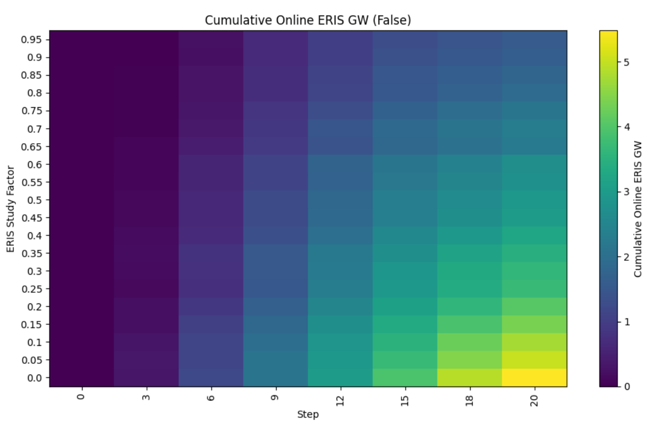


Figure 39: Heatmap of ERIS Study Factor and Cumulative Online ERIS GW

The share of online MW that is ERIS also varies as expected with the ERIS study (Figure 40) As the ERIS study factor decreases, the share of ERIS agreements becomes greater, particularly in earlier rounds, demonstrating that ERIS agreements are coming online more quickly than NRIS agreements as they have lower study times. These early round differences become less pronounced as steps progress and NRIS becomes the dominant service type. However, even in round twenty, the impact of ERIS study factor variation is seen as the ERIS share ranges from around 5 GW to 0 GW, still a significant range.

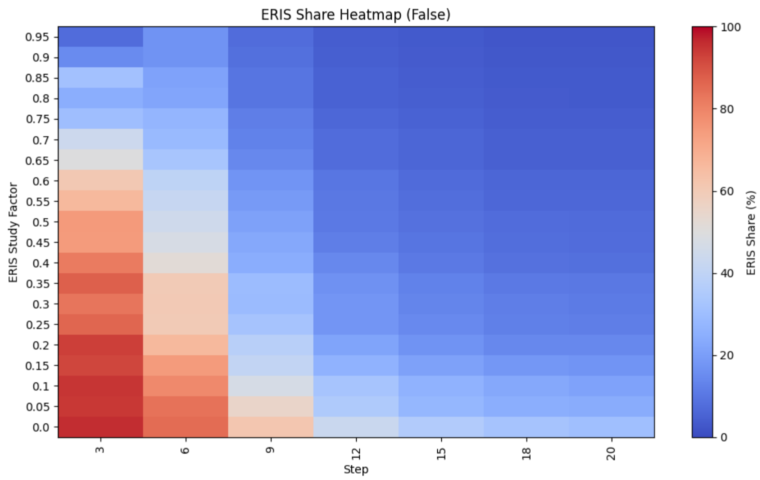


Figure 40: Heatmap of ERIS Study Factor and ERIS Share of Added Capacity since Step 0

7.2.2 ERIS NU Factor

Next, a series of experiments were conducted to investigate the impact of the network upgrades factor on the adoption of ERIS agreements to the grid. The experiments were conducted from 0:1 with increments of .05. The results demonstrated that the ERIS adoption, as MW ERIS and MW ERIS/MW total, is sensitive to the assigned network upgrade values (Figure 42). It was discovered that there exists oversensitivity of ERIS GW online to net factor under 0.05, demonstrated by the steep slope to the left of the dashed red line (Figure 41). Since zero is an unrealistic network upgrade cost, the heat map in Figure 42 uses values above 0.05. The limited impact of network upgrade factor is representative of the set up of the baseline scenario.

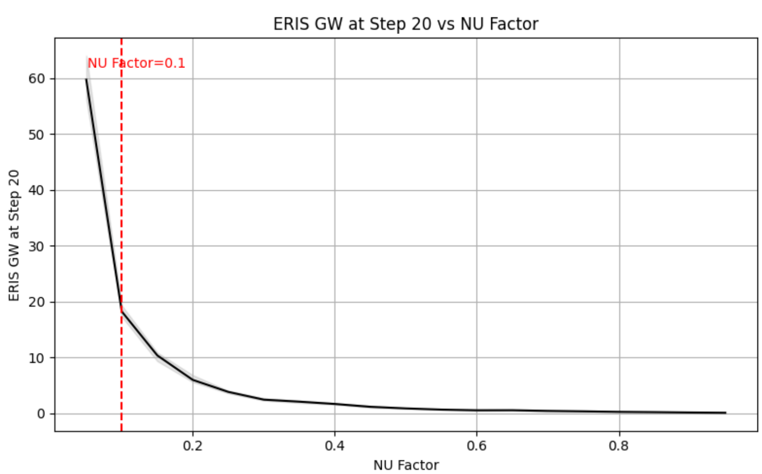


Figure 42: Step twenty ERIS GW online by NU Factor

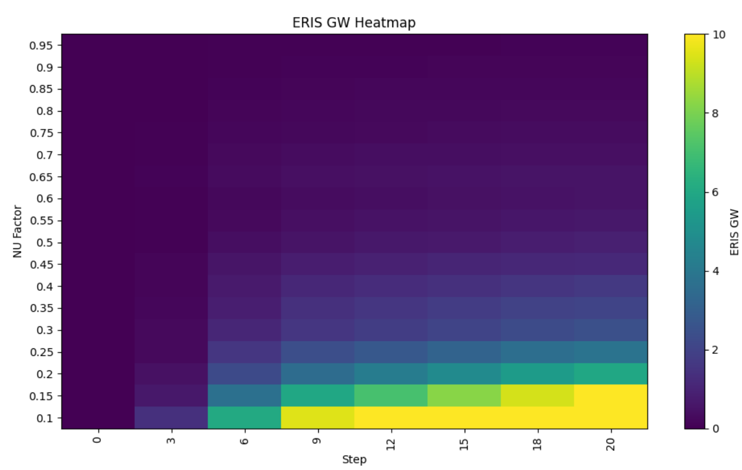


Figure 41: Heat Map of NU Factor and ERIS GW

7.2.3 Capacity Multiplier

Next, a series of experiments was conducted to investigate the impact of the capacity multiplier on the adoption of ERIS agreements to the grid. The capacity multiplier determines how much capacity is available on the grid at round zero. The experiments thus test how sensitive the model is to starting values. The experiments were conducted varying the capacity multiplier from 0:1 with increments of .05. The results demonstrated in Figure 43 that the cumulative NRIS at the end of the model is very dependent on this starting condition, as NRIS uses up available capacity. However interestingly, the total available capacity at the end of the model's 20 steps converges, indicating a lack of path dependence from the starting capacity to where the model merges. Available capacity is used up very quickly as it is not expensive to connect when headroom is available, then as assigned costs become higher due to limited capacity, the rate of capacity consumption flattens out.

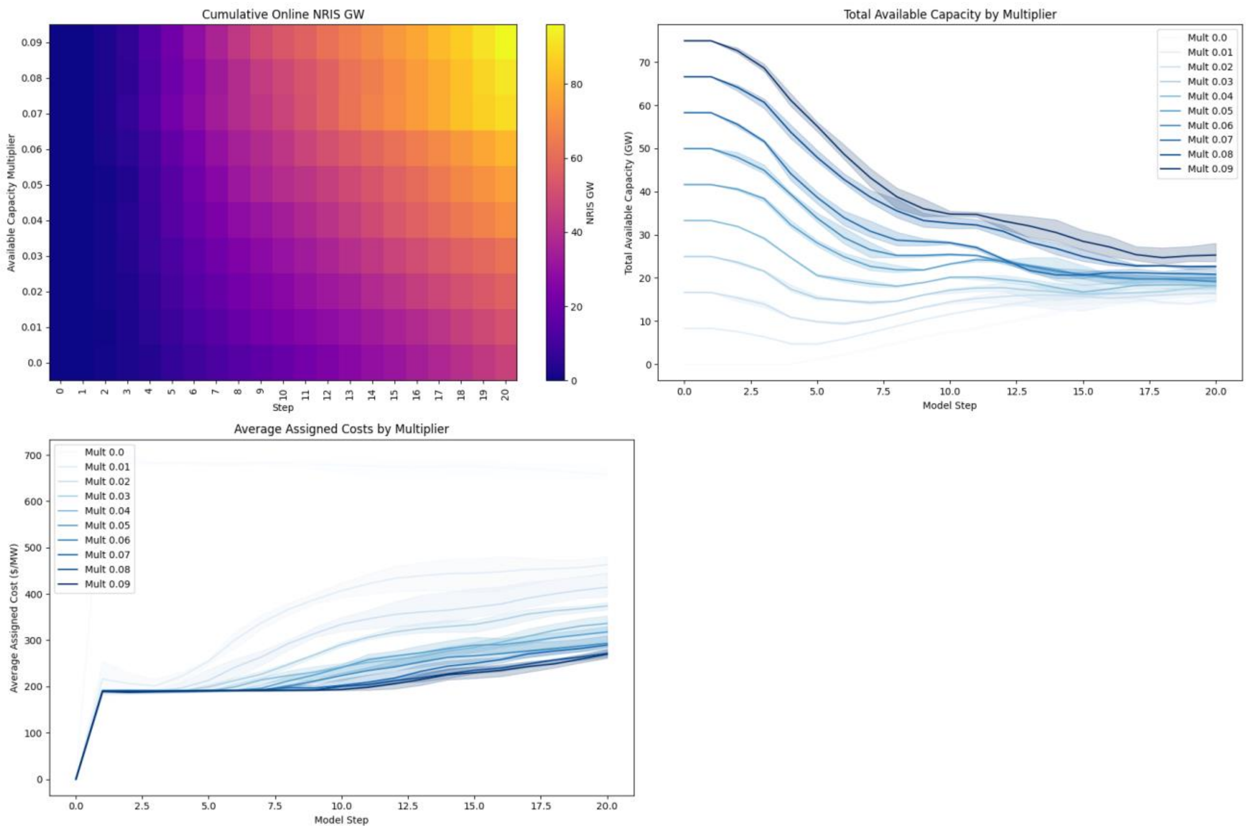


Figure 43 Results of Capacity Multiplier Variation on Online NRIS, Available Capacity, and Assigned Costs

In practice, the capacity threshold that triggers major network upgrades is uncertain and flexible, as it depends on how GETs and ATTs are modeled. These technologies can effectively raise the amount of available capacity, allowing more capacity to join the grid before upgrades are required. (Mulvaney, 2024) This, in turn, affects both the rate of capacity consumption (slope in the top-right) and the final NRIS capacity. The convergence however at the end of model step 20 suggests a natural ceiling where even where there is available capacity it is too expensive to connect there.

7.2.4 Capacity price ceiling

Next, a series of experiments was conducted to investigate the impact of the capacity price ceiling on the adoption of ERIS agreements to the grid. The capacity price ceiling determines the amount that NRIS projects would earn in the capacity market, and this value is compared to project assigned costs when NRIS developers are deciding whether or not to drop out. The heatmap in Figure 44 demonstrates that higher capacity prices spur NRIS buildout, ranging from 100 GW brought online by round 20 when the capacity ceiling is what it is in PJM in real-life of 329.19$/MW-day.

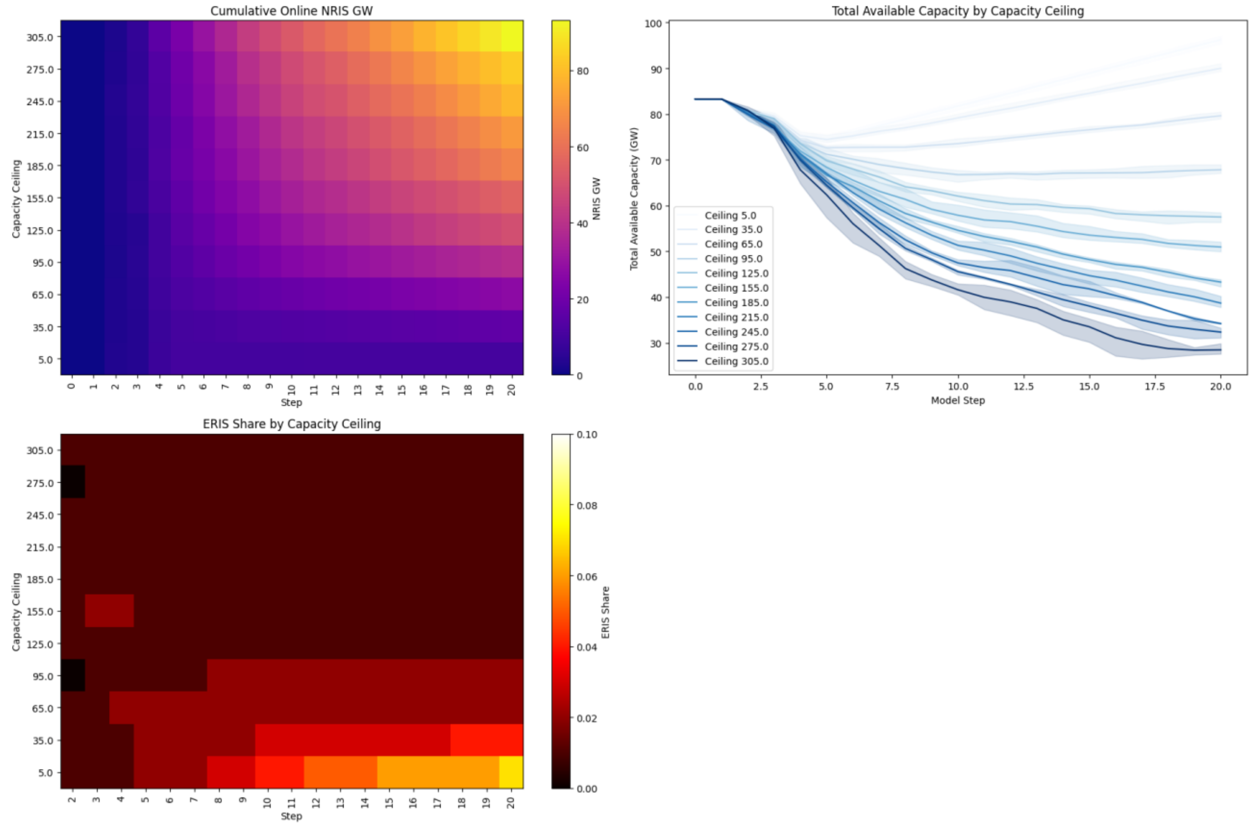


Figure 44: Results of Capacity price ceiling on Variation on Online NRIS, Available Capacity, and Assigned Costs

The capacity price ceiling is an important choice in the amount of projects getting built. NRIS projects depend on capacity revenue to justify high network upgrade costs. When the capacity price is less than 100$/MW-day less than 40 GW are brought online by round 20. Additionally in Figure 44, the available capacity is quickly eaten up at higher price ceilings, while when the ceiling is under $95, capacity actually increases after round 5 as transmission build out paces generation capacity added. Finally in Figure 44, the share of ERIS agreements remains at around 2% under all capacity market prices above $95 and is maximum of 10% at round 20 when the capacity price is $5/MW-day.

7.2.5 Transmission Magnitude

Next, a series of experiments were conducted to investigate the impact of the transmission magnitude on the model outputs. The transmission magnitude was varied from 200 to 1500 MW at intervals of 200 MW. In the base case scenario (Table 19) transmission was built every five years at a magnitude of 500 MW at three nodes. This comes at the end of round 20, 6GW of capacity built. In this situation, the end MW of capacity built varies from 2.4GW to 18GW.

Figure 45 demonstrates that less transmission builds results in higher network upgrade costs assigned on average. However, for the whole range of transmission magnitudes, from round 0 to round 2 no projects are assigned costs since it takes two rounds for a study to be completed. Then from rounds 2-5 the assigned costs are very small in range and just under $200/MW, representing projects are utilizing available capacity at chosen nodes. Then at round 7, all of the low-cost available capacity is used up and costs begin to increase, more so for those scenarios in which transmission build out is limited. There is a wide standard deviation of 8% for transmission build out magnitude of 600MW, suggesting that the cumulative MW of developers applying to nodes with 600MW of new available capacity is sometimes over and sometimes under 600MW depending on the model run.

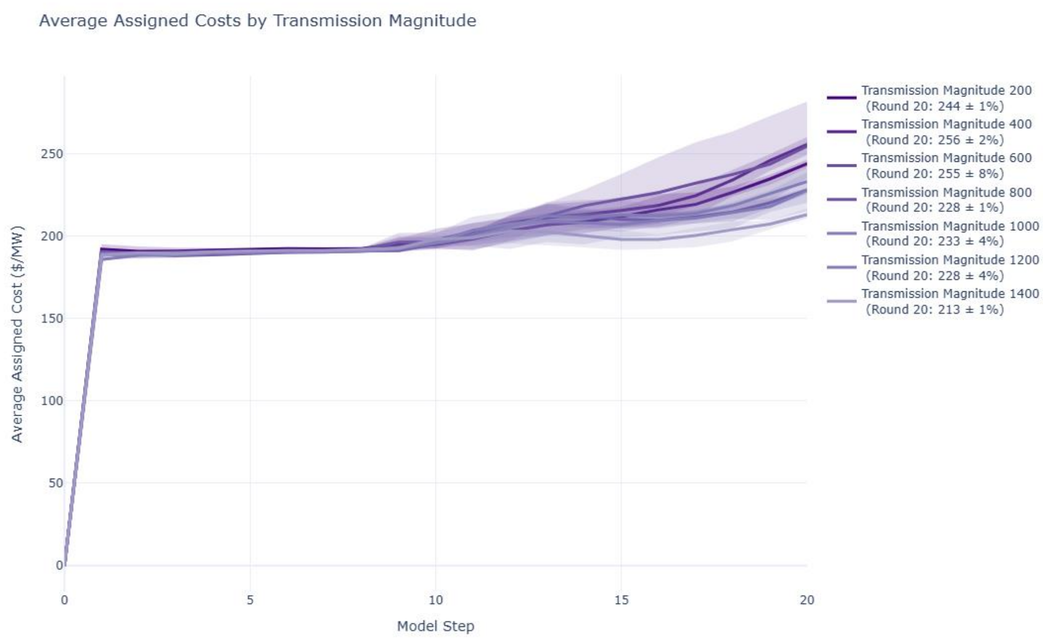


Figure 45: Results of Transmission Magnitude on Variation of assigned costs

Figure 46 demonstrates that the differences in end capacity available are greater than the differences in capacity built. That is to say that the changes in transmission magnitude have effects on system flows. Because the transmission is being built at the most congested nodes, which are also nodes with lower network upgrade costs, more projects stay in the queue after cost assignment. Less projects are being built in higher transmission cost assignments. However, because transmission construction does not always occur at locations with the lowest network costs or at sites most frequently selected by developers, some projects still drop out of the queue from high network upgrade costs.

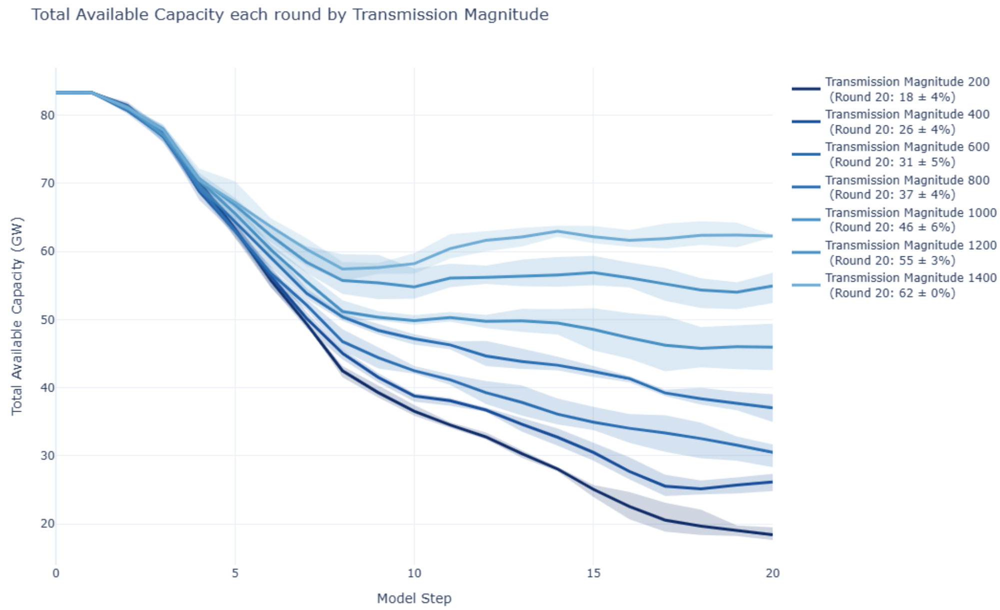


Figure 46: Results of Transmission Magnitude on variation of total available capacity

7.2.6 Transmission Build Speed

Next, a series of experiments were conducted to investigate the impact of the transmission build speed on the model outputs. The transmission build speed was varied from 1 to 10 years while the total magnitude of transmission built by the end of round 20 remained constant. In the base case scenario (Table 19) transmission was built every five years at a magnitude of 500 MW at three nodes. This comes at the end of round 20, 6 GW of capacity built. To represent the same amount of transmission built but with a more frequent cadence, 250 MW was built every 2.5 years at three nodes, also resulting in 6 GW built by the end of round 20. The cadence of transmission is important. The incumbent transmission build out are long time intervals and large projects, a chunky implementation. An alternative with the same funding, for instance, is a smoothed implementation of a higher cadence of implementation of smaller size, representing, in one conceptualization the phased implementation of larger projects or many smaller projects. This is more interesting than simply increasing the transmission build speed because functionally that would represent more transmission build out generally, without focusing on isolating the impact of the frequency of the buildout.

Figure 47 demonstrates that the cadence of build out is not a significant factor in the average assigned costs. All final costs fall within a $30/MW range. Similarly Figure 48 demonstrates no significant impact of the transmission timing, as the available capacity at the end of round 20 is the same, so whether new capacity is added quickly or over time, if it is the same magnitude in culmination, the capacity is not consumed more or less quickly.

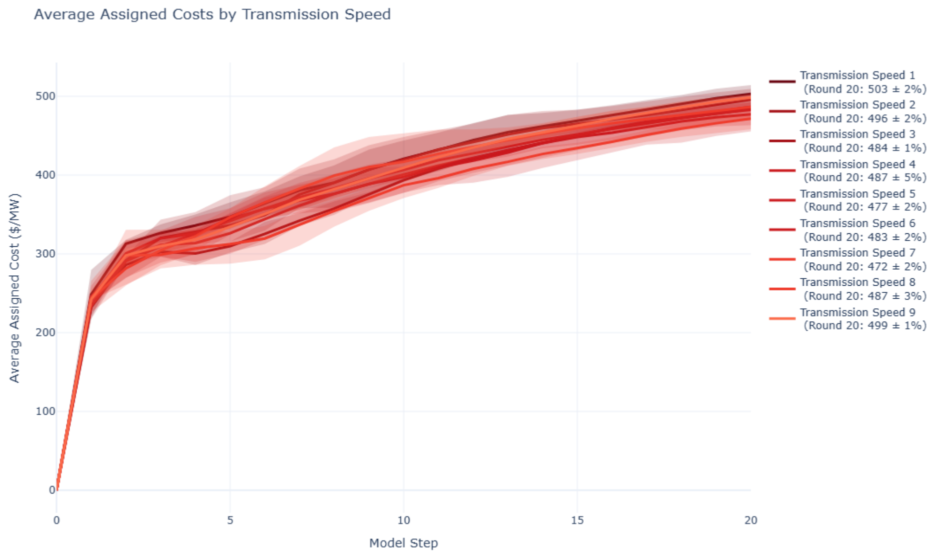


Figure 47: Results of Transmission Speed on variation of assigned costs

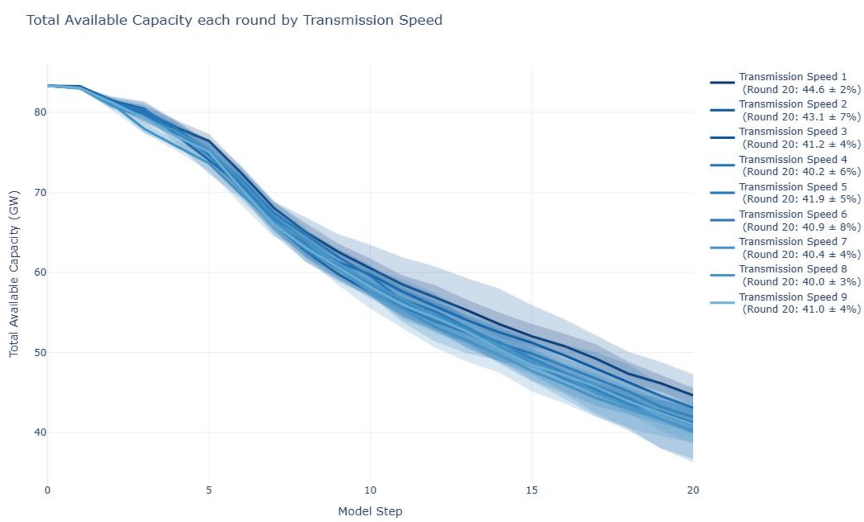


Figure 48: Results of Transmission Speed on variation of available capacity

7.2.7 Developer Batch Size

Finally, a series of experiments were conducted to investigate the impact of the developer batch size per round on the model outputs. The size of the developer batch each round is based on PJM's actual TC1 queue of about 40 GW of applicants. The size of the developer batch was varied from 10-100 GW at intervals of ten. The results in Figure 49 demonstrate a large crowding affect. This could be remedied by not capping the restudy amounts at two cycles, and running restudies until the dropout percentage is less than a certain values, or by reducing the number of developers that continue to submit applications in successive rounds. Developers collectively trigger expensive upgrades and subsequently drop out in large numbers.

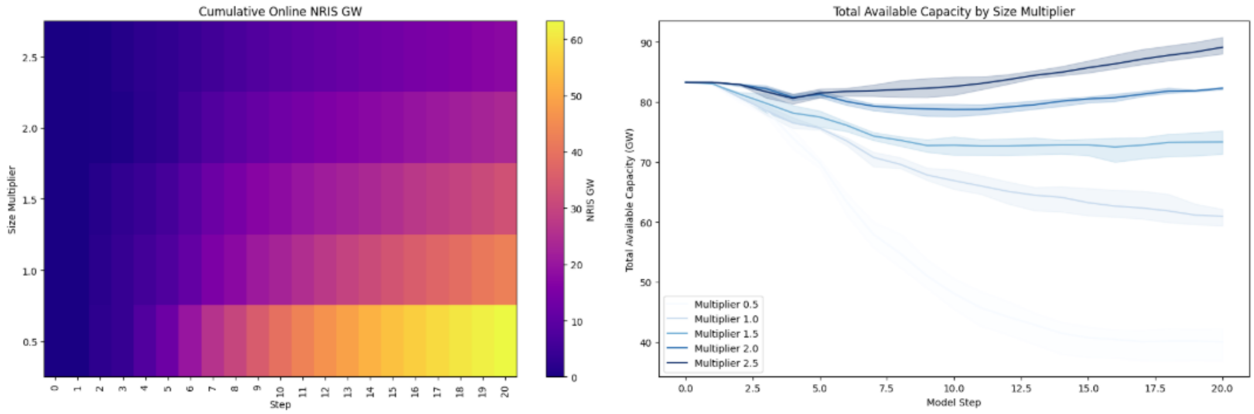


Figure 49: Results of developer batch size on variation of available capacity

7.3 Summary

Chapter 7 has presented the development, calibration, and experimentation of the ABM representing PJM's interconnection process. The baseline model, built in Python using MESA and parameterized with real-world data, was validated against historic PJM outcomes. Key outputs, including gigawatt added per round, project dropout rates, developer service-type choices, and nodal project distributions, closely match observed data, demonstrating that the model sufficiently replicates current system behavior. Sensitivity analyses were conducted on key parameters such as the ERIS study factor, network upgrade factor, capacity multiplier, capacity price ceiling, transmission magnitude and cadence, and developer batch size. These experiments reveal that ERIS adoption is sensitive to study times and network upgrade allocation, with early-round dynamics strongly influenced by faster study times. Capacity multiplier and price ceiling affect the pace of buildout, but cumulative system capacity converges, suggesting natural constraints on development. Transmission design (magnitude and cadence) primarily affects assigned costs and available capacity in early rounds, but cumulative outcomes converge if total capacity built remains constant.

Developer batch size triggers larger crowding effects, influencing dropout rates and network upgrade costs. Overall, the baseline model demonstrates stability, realistic outputs, and robustness across a wide range of parameter values. This establishes a solid reference scenario against which proposed reforms and policy interventions can be tested. The next chapter explores these reform scenarios to evaluate potential improvements to the interconnection process.

Chapter 8 Reform Scenario Results

In this chapter, two reform scenarios designed in Chapter 5 are conducted by adjusting the base model scenario parameters. The implications and the validity of the model results are discussed at the end of the chapter. Possible further reform scenario 3 is discussed in Appendix C.

8.1 Reform Scenario 1: Study and Cost Differentiation

In this Reform Scenario, the PJM RTO studies ERIS applications quickly and without consideration of NRIS restudy requirements if NRIS projects dropout. ERIS projects pay only the cost for infrastructure related directly to the physical connection to the grid and not wider network upgrades.

Table 20: Parameter Changes between Reform 1 and Base Case

Model Parameter	Reform 1	Base Case
ERIS_differentiation	TRUE	FALSE
ERIS_study_factor	0.6	1.0
ERIS_NU_factor	0.6	0.8

Decreasing the study and network upgrade factor increases the base probability that a developer chooses ERIS:

base_prob_eris = ((1 - self.ERIS_study_factor) + (1 -self.ERIS_NU_factor)) / 2

Turning ERIS differentiation to TRUE determines that ERIS projects are assigned the lowest tier of network upgrades costs.

If ERIS_differentiation==True and project_agent_service_type==ERIS
assigned_cost = nu_tier_0

These reduced costs reduce construction time for ERIS:

dev.construction_time = min(dev.assigned_cost /1000 + delay_factor, 7)

The hypothesis for Reform Scenario 1 is that by studying ERIS agreements separate from NRIS agreements and assigning ERIS the minimum network upgrades, ERIS will have shorter study times, less dropouts, and no restudies required. Their assigned costs will be low and construction time short, allowing the ERIS projects to get connected quickly. The second order effect hypothesized is that the NRIS projects will also see fewer dropouts and less assigned costs since the ERIS projects are not included in the calculations for triggering cost thresholds in the network upgrade piecewise function, allowing more NRIS projects to join the grid as well, compared to the baseline scenario.

Results

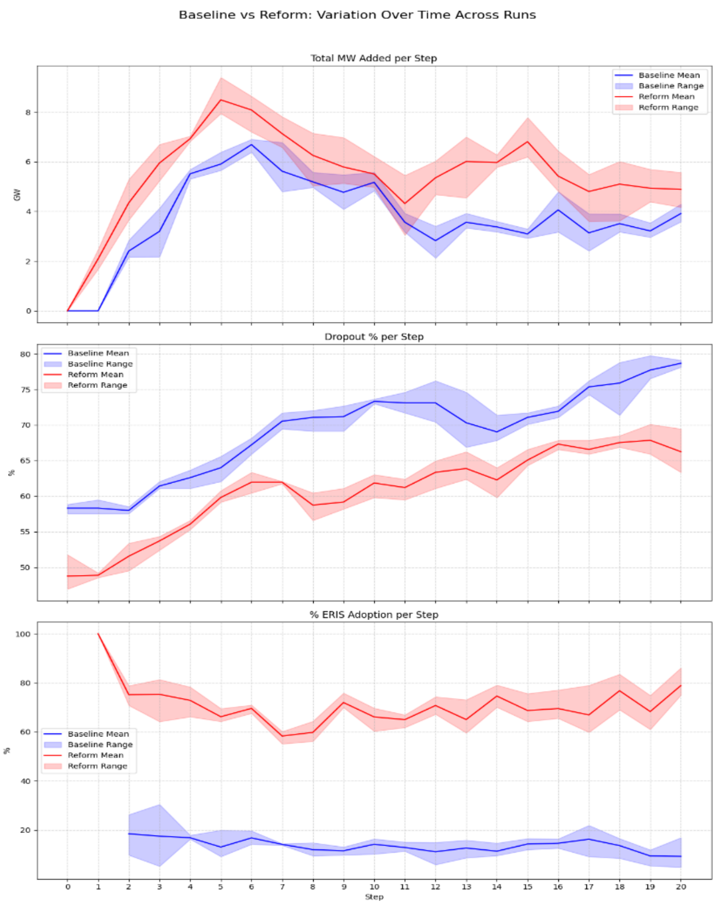


Figure 50*:* Reform 1 Results Compared to Base Case (MW added, Dropout %, ERIS Adoption %)

The changes in Reform 1 allowed many more projects to connect to the grid (Figure 50, Total MW added per step), most of which were ERIS projects (Figure 50, % ERIS Adoption perstep). Fewer projects dropped out over all (Figure 50, Dropout % per step). These results confirm that reductions in studies times and assigned costs in ways that treat ERIS as appropriate to its deliverability type would in fact ensure more generation connects to the gird, even as capacity is constrained.

However, the expected second order effects of this reform scenario did not materialize. The changes did not enable more NRIS projects to join than the baseline scenario (the solid red line is lower than the solid blue line). The baseline probability of choosing ERIS projects as a service type increased such that less project developers are choosing NRIS in the first place.

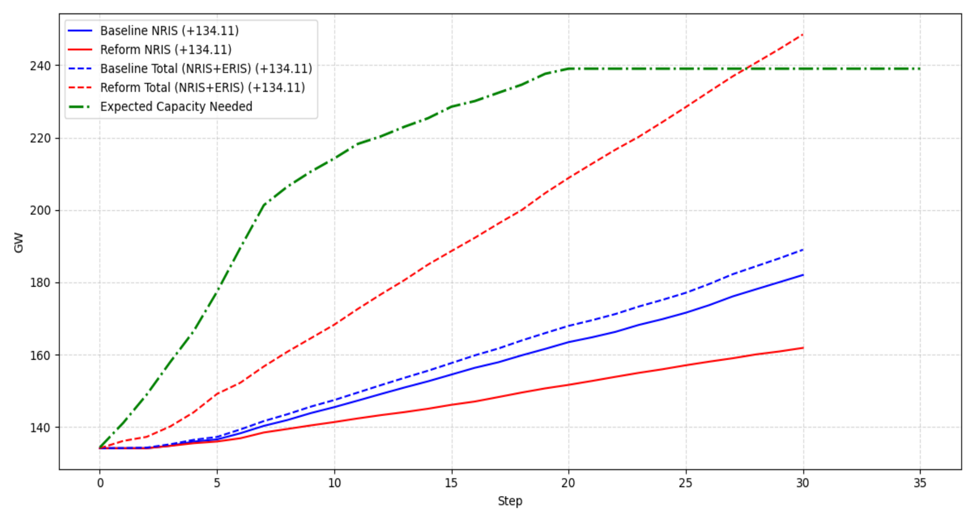


Figure 51: Reform 1 MW Added (Total and NRIS) compared to Base Case

Even though the assigned study times and network costs are less for NRIS in the reform scenario, ERIS is still more attractive to developers. Consequently, as in the base case scenario, the capacity market remains at its ceiling as not enough accredited capacity (NRIS) is added each round.

This reform successfully reduces the interconnection queue time and gets more MW in service that are ERIS. However, within the current PJM reliability structure, resource adequacy remains a problem.

8.2 Reform Scenario 2: Infrastructure Investment with Capacity Market Ceiling

In this reform scenario, the impact of PJM RTO's transmission investments adds 1000 MW of available capacity every five years at the top five congested nodes instead of only 500 MW of available capacity at the top three nodes. Additionally, the amount of available capacity on the grid is 20% of the existing grid capacity instead of 10%, representing investments in GETS/ATTS that increase the amount of capacity the grid can host without massive bulk investments in new lines, for instance. The capacity market ceiling is reduced to $150/MW-day, representing a PJM market reform.

Table 21: Parameter Changes between Reform 2 and Base Case

Model Parameter	Reform 2	Base Case
Transmission_magnitude	1000	500
Transmission_node_number	5	3
Transmission_speed_	5	5
Available_capacity_multipler	0.2	0.1

The code for Reform Scenario 2 is as follows:

```
    top_nodes = sorted_by_congestion[:self.transmission_node_number]
past congestion for node, _ in top_nodes:
        node.congestion_indicator -= 2
        node.available_capacity += self.transmission_magnitude

Available_capacity=row['generation']*self.available_capacity_multiplier,
        MW_threshold_1=row['generation']*self.available_capacity_multiplier,
        MW_threshold_2=row['generation']*self.available_capacity_multiplier*3
```

The hypothesis for Reform Scenario 2 is that by increasing the amount of capacity available in the beginning and adding more available capacity, assigned network upgrade costs will be low, and subsequent dropouts will be low for both ERIS and NRIS agreements, allowing both service types to be successful. Additionally, the low-capacity market prices should encourage more ERIS adoption.

<u>Results</u>

Until round 12, Reform Scenario 2 adds more GW of resources each round than Reform Scenario 1 and Baseline Scenario. At round 12, the accessible capacity has been used up (Figure 52). Projects come online steadily until round 5, after which MW added per round generally decreases, with plateaus following the years transmission was built (round 5-6, 10-11, and 15-16).

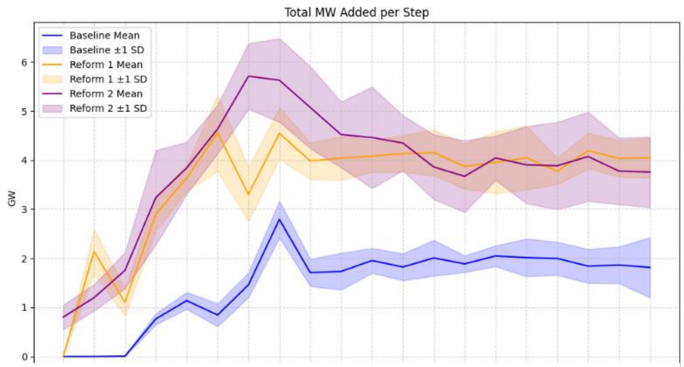


Figure 52: Reform 2 MW added Compared to Reform 1 and Base Case

The dropout percentage increases as assigned costs increase, but remain less than the 80% dropout rate of the baseline case. The more significant and step delayed dip in dropouts compared to Reform Scenario 1 between round 1 and 2 is due to less projects choosing ERIS in Reform Scenario 2 than in round 1, so projects were assigned higher costs and dropped out more in those early rounds (Figure 53).

ERIS adoption in Reform Scenario 2 was less than in Reform Scenario 1 but more than the Baseline Scenario as a result of a less lucrative capacity market for NRIS projects (Figure 54).

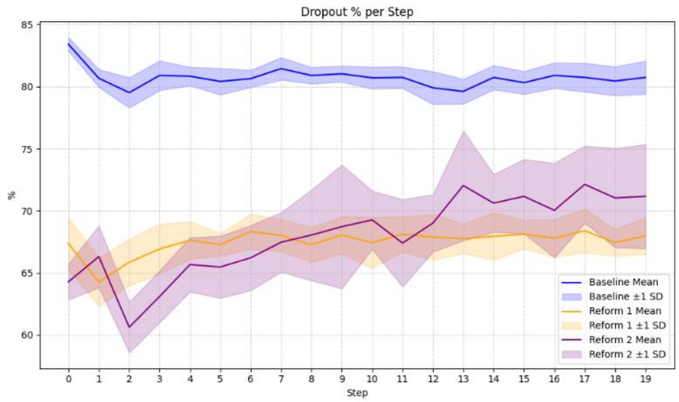


Figure 53*:* Reform 2 Dropout % Compared to Reform 1 and Base Case

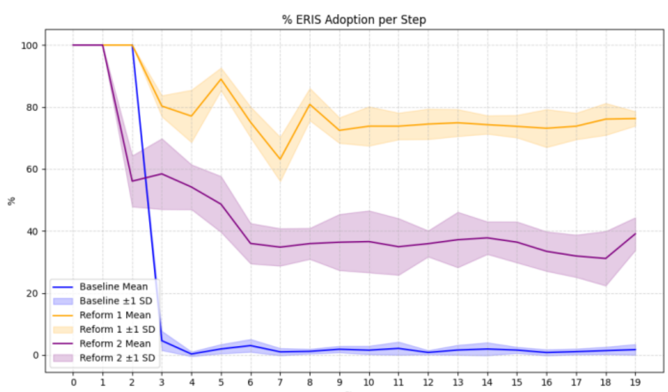


Figure 54: Reform 2 ERIS Adoption Compared to Reform 1 and Base Case

In both reform scenarios, the capacity market clears at its ceiling, indicating that not enough NRIS MW are coming online. While the effectiveness of reduced ERIS study times and cost assignment is clear in ERIS adoption rate and the amount of ERIS online, the hoped for second order effects of speeding up NRIS processing did not take effect. (Reform 1) Increasing transmission capacity at more nodes, accelerates MW additions in early rounds and encourages an intermediate level of ERIS adoption is intermediate between Reform Scenario 1 and the baseline (Reform 2).

Chapter 9. Conclusion and Discussion

This research addressed a critical knowledge gap on understanding how interactions between project developer incentives and PJM system dynamics result in very low ERIS adoption. Institutional analysis was applied to design an Agent Based Model capable of simulating the interactions between project developers, transmission owner zones, and the PJM RTO, and representing real-world output metrics. This understanding enabled the development and testing of reforms within the model to encourage wider ERIS adoption, contributing to improved interconnection queue process outcomes. This chapter will summarize responses to the research questions, discuss implementability of reforms, and present options for further work.

9.1 Answering the Research Questions

Subquestion 1: *What factors shape how developers choose between ERIS and NRIS agreements in PJM?*
The factors influencing this decision, identified in Chapters 3 and 4, were incorporated as variables and parameters within the ABM. Developers are primarily profit-motivated but exhibit varying risk tolerances, balancing potential revenues against anticipated costs. Their decision-making is strongly influenced by the stability and magnitude of projected revenue streams. While most revenue derives from the energy market, accurate forecasting is complicated by redispatch variability and transmission congestion, making resource type and siting decisions challenging. Capacity market revenues add further uncertainty due to shifting accreditation methodologies and evolving load demand curves. On the cost side, developers aim to minimize assigned network upgrade expenses and seek points of interconnection with greater available headroom. They are also sensitive to extended study and construction timelines, as prolonged development periods increase financial risk, complicate debt servicing, hinder financing arrangements, and delay returns on investment.

Subquestion 2: *How do developers respond to policy signals, peer behavior, and system constraints when selecting ERIS or NRIS agreements?*

Chapters 5 and 7 build from the understanding of factors developed from answering Subquestion 1 to answer Subquestion 2. Developers increase their probability of selecting ERIS service if there is clear and communicated benefits in study speed and assigned costs by doing so. Projects with storage capabilities have great probability of selecting ERIS because they have an additional energy revenue stream of energy arbitrage available to them to offset lack of capacity market payments and curtailment risks. Developers learn from their past dropouts and select nodes with high marginal prices, low congestion, and perceived available space. At nodes with high NRIS buildouts, developers consider ERIS to free ride on the infrastructure. Project developers face internal calculations on whether to dropout or not depending on their own risk tolerance, project type, and balance of assigned costs to predicted revenue. When many developers apply to the same node, costs are driven up, as are dropout rates. Building transmission at the most congested nodes offers temporary relief from high network upgrade costs, but if projects are not spread out to applying and more numerous nodes, available capacity is quickly used up sometimes without any network upgrade cost reductions since too many developers applied there to stay underneath the first cost threshold. A capacity market ceiling encourages projects to apply as NRIS and remain in the queue even under high-cost assignment.

Reduction in the capacity market price encourages more ERIS adoption as more projects fail to make it through the queue as NRIS. Concerningly, under given load growth projections, no modeled scenario gets enough NRIS projects online quickly enough to clear beneath the capacity market ceiling.

Subquestion 3: *How could targeted reforms shift developer behavior and improve interconnection outcomes in PJM?*

Two reforms were designed in chapter 5.2 based on the understanding of the system structure and the solution space to answer Subquestion 3. These reforms were run in the ABM and the results discussed in Chapter 8. Reducing study time and network upgrade costs assigned to ERIS projects is an effective way to increase ERIS adoption, get more MW on the grid, and get projects connected at a faster pace in the first few years of implementation. (Reform 1) Expanding transmission capacity while reducing the capacity market price ceiling gets ERIS adoption up to 40%, doubles the amount of MW added each step, and decreases dropouts to around 70%. (Reform 2) These reforms in tandem with the OATF sensitivity analysis, gives system intervene a sense on how parameters change can matter in influencing developer choices and eventual ERIS adoption on grid.

Main Research Question: *What reforms in PJM solve the misalignment between generation project developer incentives and the need for greater PJM system-level ERIS adoption to improve the interconnection process?*

The tested reforms offer insight into institutional changes that increase ERIS adoption in PJM. The parameters included and tested in the model can be combined in different ways to influence ERIS adoption and system outcomes. From the model experimentation and reform scenario results, three recommendations emerge.

Use Distinct ERIS Study Methodology

Meaningful cost distinctions between ERIS and NRIS need to materialize for developers to even consider applying for ERIS service. This cost assignment can occur by changing the way in which ERIS projects are studied.

PJM should establish a study methodology for ERIS that is separate from NRIS clusters, both in process and in contingency severity. This includes:

- Excluding ERIS projects from triggering thermal or steady-state reliability upgrades that are strictly tied to NRIS requirements,
- Setting a maximum $/MW cap for network upgrade costs assigned to ERIS,
- Implementing lenient contingency and dispatch assumptions for ERIS compared to NRIS,
- Firewalled cluster studies to ensure NRIS studies do not delay ERIS projects,
- Prioritizing automation in ERIS study processes to deliver faster results.

2. Increase Grid Hosting Capacity at the Lowest Cost

Relying on the generation interconnection process as the primary driver of grid development is economically inefficient and creates persistent bottlenecks. When network upgrades that serve broad, system-wide purposes are assigned to individual projects, they distort cost allocation, delay project completion, and discourage developersfrom entering or staying in the queue. PJM should prioritize proactive, regional transmission planning to maximize hosting capacity and reduce reliance on piecemeal interconnection-driven upgrades. This includes

- Increasing the cadence and scale of transmission investment to match the rapid pace of resource development,
- Implementing right-sized transmission planning that anticipates and guides future generation clusters rather than reacting after congestion emerges,
- Preventing overbuilding or misallocated upgrades, ensuring individual projects are not burdened with costs for system-wide benefits,
- Deploying automation and advanced grid management technologies (e.g., grid-enhancing technologies, dynamic line ratings) to increase the usable capacity of existing infrastructure,
- Accelerating interconnection timelines by removing long-horizon, regionally beneficial upgrades from the critical path of individual projects.

9.2 Modeling Limitations

The purpose of this model is not to replicate reality but to understand the behavior of systems and the effects of changes. Indeed, statistician George Box memorably said “all models are wrong, but some are useful.” Chapters 7 and 8 demonstrate the utility of this model in understanding the PJM generator interconnection process dynamics in terms of agent interactions. While the current version provides meaningful insights that could be considered to understand the system behavior in different ways.

In the first category, **s**pecific improvements to model input**s** may be possible as additional data becomes available. For instance, as PJM releases more interconnection study results under the new cycle study process, better information on assigned network upgrades and their costs will emerge, enabling more precise modeling of these factors. A key current limitation, which also mirrors a real-world information asymmetry faced by developers, is the uncertainty surrounding network upgrade costs across transmission zones and resource types. Similarly, a larger dataset would improve the dropout function by clarifying the financial thresholds at which developers exit the queue. Confidentiality PPAs also constrains insight into the prices developers receive for energy production and whether ERIS and NRIS projects are treated differently in these contracts. Further improvements could also result from greater stability in PJM’s ELCC calculations and the administratively set capacity market demand curves; standardizing these year to year would reduce uncertainty. Finally, the model could be extended to include more dynamic developer cohorts, where project size and resource types adapt over time in response to changing system conditions.

More fundamental changes to the modeling framework could also be explored to capture different dimensions of system behavior. While ABMs can represent strategic interactions, they are not designed for detailed power flow analysis. Incorporating or conducting separate power flow modeling would enable a more accurate representation of storage developers' potential revenues from energy arbitrage, regardless of NRIS status. It would also allow for explicit modeling of locational dynamics within and between transmission owner zones including actual transmission constraints and real-time economic dispatch that influence project economics and expected revenues.

9.3 Further Research

The existence of a *Regional* Transmission Operator in this problem space provides the advantage of a critical platform and centralized body for coordinated, system-wide interventions, even if alongside the challenges of incumbency bias, path dependence, and the inertia of large regulatory institutions. The reform space explored in this study considers how the PJM RTO could leverage this position to address current problems. The two implemented reforms in this research focused on the parameters of the capacity market ceiling, ERIS study and cost factors, and transmission build-out magnitude and locations. However, several other reforms warrant exploration, some of which are directly translatable into the model. One such reform would address the information asymmetry between project developers and PJM. The PJM RTO could make perfect information available about capacity headroom at all points of interconnection, and projections of network upgrade costs there. By providing perfect information on capacity headroom at all points of interconnection and transparent projections of network upgrade costs, developers could make more informed decisions. This reform would require a modernized, automated study process to replace the current multi-month, largely manual approach. An automated study process would get the same answers more quickly, but could also be used to improve outcomes by incorporating consideration of advanced technologies to reduce the assigned network upgrade costs. Transparency on what network upgrades were considered to solve model contingencies could allow developers to suggest alternative means to address contingencies, introducing cost competitiveness to the interconnection process. Perfect information on available capacity could initially lead to clustering behavior, where developers concentrate at a few highly attractive points of interconnection. However, if studies were processed quickly, developers could iterate strategies more dynamically such as holding positions while waiting for other projects to withdraw, or pivoting to alternative locations as opportunities emerged Another interesting reform category would be to allow allows existing ERIS to switch to NRIS at any point, thus framing ERIS as a provisional type of interconnection service rather than a static categorization. Then project developers could get connected to the grid as ERIS projects and earn energy revenues while waiting to be studied for NRIS or wait for the network upgrade construction to be completed. Most reform categories rely on PJM fundamentally differentiating how they study ERIS projects from NRIS projects. Until this occurs, there fundamentally is only one service type in PJM.

Outside of the current model's scope, but of research interest, are reforms that create separate interconnection processes for specific generation. For instance, projects could be procured in tandem to transmission expansion in certain regions and the grid would be designed for their connection, rather than new generation seeking to connect to an existing grid region and go through an interconnection queue. These sort of separate tracks and fast tracks could present challenges to PJM RTO's open access principles. There is no shortage of what could be done, the challenge is picking what can be done now to maximize impact. Starting with true cost and study differentiation, lowering the capacity market cap, and making meaningful investment in the transmission grid should be priorities for getting projects to select ERIS type in the queue and bolstering their odds of making it to commercial operation.

9.4 Reflections

The transformation of a complex system such as the PJM electric grid to accommodate growing load and the interconnection of diverse and numerous renewable resources necessitates intentional interventions that shape fundamental interactions for the desired outcomes. The interconnection queue bottleneck is symptomatic of incumbent processes and interactions ill-suited to meet the current context. It is advantageous that desired outcomes of project developers (get connected to the grid), PJM RTO (maintain grid reliability), and society (clean, affordable energy) can all be put in alignment fixing the interconnection queue process. All the resources we need are simply waiting in the queue, if we can just get them online. This research maps the generation interconnection to identify the targeted ways to use ERIS as a means to loosen this bottleneck. The tested and proposed reforms in this model each can play a part in reshaping processes and interactions in the generation interconnection process to get clean energy online more quickly and at lower costs. Change happens on many time scales. Some interventions, like study methodologies and cost assignment practices can happen on shorter time scales within PJM's regulatory processes. Others are also critical but require long term planning and investment in a transmission grid that is built for the efficient dispatch of resources. From this research it is also clear, that how PJM ensures reliability through the capacity market is not a functional market signal for investment if projects can't even get online, and only provides increasingly expensive electricity prices to pay incumbent generators more money each year for the same status as the last: simply being online. The queue is clogged with projects who have no choice but to select NRIS status, since selecting ERIS has next to no actualized benefits under the existing processes. In turn, study processes become prolonged, projects cannot afford expensive network upgrades, and those that can make it to GIA wait for years for the network upgrades to be built. Bit by bit the Interconnection process is funding the Eastern United State's grid. This larger picture requires the consideration of different means of securing grid reliability be it by moving the grid towards market redesign, incorporation of advanced technologies, more operational nimbleness, or proactive resource planning and procurement. ERIS adoption on the offers a means to a significant amount of clean energy online in the near term.

Appendices

Appendix A Institutional Analysis

Two key elements are required for a proper description of the functional relationships of a system: frameworks and theories. (McGinnis, 2016) Frameworks are utilized to identify, categorise, and organise factors deemed most relevant to understand some phenomenon, Theories hypothesize causal relationships and importance among subsets of these variables to explain the phenomenon. The Institutional Analysis and Development (IAD) framework developed by Ostrom (2011) provides the structure to identify and describe the elements and factors most relevant to understand and analyse a phenomenon. The IAD framework is a multi-tier conceptual map that enables the identification of the major types of structural variables that are present in institutional arrangements. (Ostrum 2011). This chapter applies the IAD framework for a systematic examination of the interactions and interconnection choices of energy project developers in PJM. The framework has conventionally been applied to the study of common pool resource management in a natural sciences context, but the IAD framework is also applicable to network infrastructure, such as the electric grids, as literature provides that network infrastructures share key characteristics with common pool resources: non-excludability of resources, rivalry in the consumption of services, and the need for system coordination (Künneke & Finger, 2009). The IAD recently has been applied to many energy-field topics (Milchram et al., 2019) and has been recognized as a valuable tool for energy transitions (Lammers and Hoppe 2019). In the framework, the action arena is central as the place in which actors interact with each other, affected by exogenous variables (material conditions, attributes of community, and rules-in use). Thus, the IAD framework is suitable for conceptualising the complexity of socio-technical systems in agent-based models (Ghorbani et al 2010).

2.4.2 IAD Overview

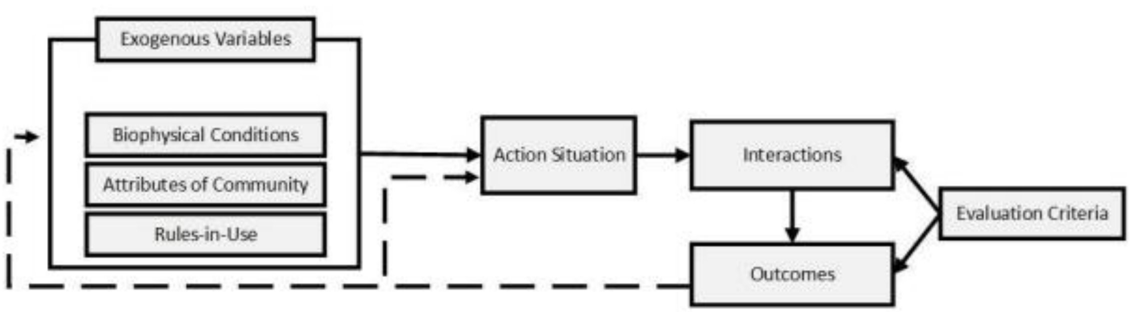


Figure 55: IAD Framework (Ostrom, 2005)

Overall, the IAD framework developed by Ostrom (2005) enables the dynamic analysis of decision making processes in socio-technical systems since it breaks and organises these systems in more simple and manageable parts. Institutions are “the set of rules that humans use to organize all forms of repetitive and structured interactions”. (Orstrum, 2005) They shape the individual and collective decision making processes by acting as constraints or opportunities. Analysis is the decomposition of the institutional contexts into their components and development is the ways in which institutions evolve as a result of internal to the institution as well as external variables. (McGinnis, 2016)

The first step in analysing a problem is to identify a conceptual unit deemed in the IAD as an “action-situation”: the “a conceptual space in which actors inform themselves, consider alternative courses of action, make decisions, take action, and experience the consequences of these actions” Polski and Ostrom (1999) The action-situation is described by seven key variables (Ostrom, 2011): the characteristics of the actors, their roles the range of actions they can take and the potential outcomes, the cost and benefits of those actions and outcomes, the available information they have, and the level of control over their decisions.

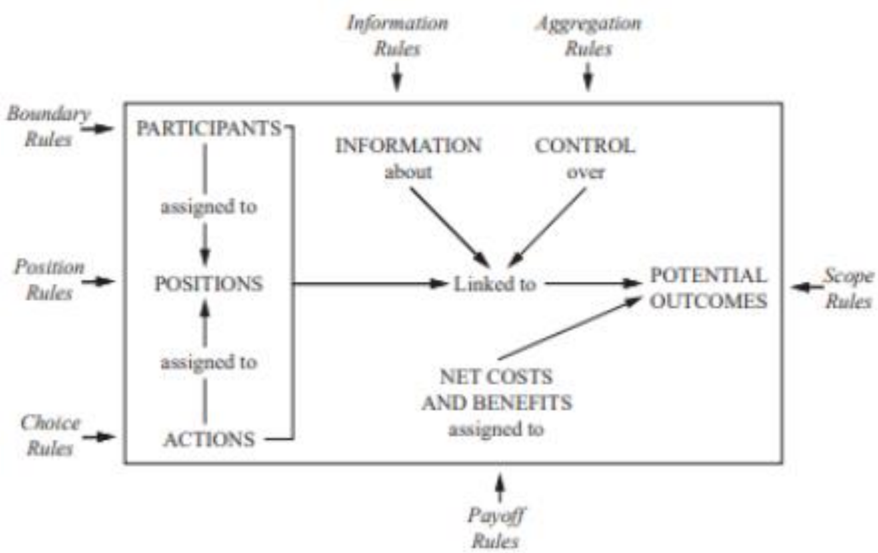


Figure 56: Action-Situation and rules as exogenous variables, adapted from (Ostrum, 2005)

What happens in the action situation is influenced by a series of exogeneous variables that cover all the social, cultural, institutional, and physical contextual aspects in which the action situation is situated (McGinnis, 2016). These are classified in three different categories: biophysical conditions, community attributes and rules in use. The biophysical conditions include the physical and material resources and capabilities available within the system’s boundaries (Polski and Ostrom, 1999).Community attributes include the cultural and social context in which the action situation is situated. The rules in use define the possibilities of the action situation: position, boundary, authority, aggregation, scope, information, and pay-off.

The interactions between the actors in the action arena which are influenced by the exogeneous variables lead to particular outcomes. These outcomes can be objectively assessed on the basis of an evaluation criteria either by the participants themselves or the external observers (Ostrom, 2011). These criteria is used to determine which aspects of the observed outcomes can be considered successful (McGinnis, 2016). The IAD framework accounts for feedback loops, learning processes, and nestedness. That is, that the outcomes of an action situation may impact the exogenous variables of an action-situation in a lower layer of analysis. (McGinnis, 2016)

Appendix B Role of States and ABM Logic Expanded

States within PJM are not direct parties to interconnection service agreements nor involved in PJM governance. However, state governments set renewable portfolio standards, issue siting and permitting approvals for transmission and generation facilities, and can influence the pace and composition of resource development through regulatory policy. Their interests often center on achieving state-level policy goals—such as decarbonization targets, economic development, and grid resilience—while maintaining affordable electricity prices for constituents. State public utility commissions (PUCs) typically engage with PJM through formal stakeholder processes, regional planning initiatives, and through coordination with transmission owners operating within their jurisdiction. States with ambitious clean energy targets often advocate for expedited interconnection timelines, more proactive transmission planning, and cost allocation methods that support renewable resource integration. Conversely, states more reliant on incumbent fossil generation may prioritize cost containment, reliability assurances, and slower policy transitions to minimize impacts on legacy industries and ratepayers. The diversity of state policies across PJM's footprint—from aggressive offshore wind mandates in the Mid-Atlantic to more cautious or fossil-favorable stances in other states—creates a patchwork of regulatory preferences. This heterogeneity complicates the development of uniform interconnection reforms and can result in conflicting pressures on PJM to both accelerate renewable integration and protect against perceived cost shifts or reliability risks. Recently, governors in several states have expressed growing frustration with high capacity prices and the perceived lack of responsiveness from PJM. (Governors, 2025) Motivated both by their political imperative to keep electricity affordable and by mounting pressure to deliver on clean energy promises, some governors have threatened to withdraw their states from PJM, proposed their own nominees for the PJM Board of Managers, and are convening a multi-state summit to explore collective bargaining leverage. This dynamic underscores the increasing willingness of states to assert their authority over regional transmission governance when market outcomes are viewed as misaligned with state policy goals.

States ABM Application

States are not directly coded into the ABM as actors. However the output of the model includes the amount of clean energy brought online under different scenarios, which impacts both state clean energy and affordability goals.

Table 22: Summary of Model Decisions and Factors at Each Phase

Phase	**Logic for input factors**	**Output**
Location	Nodes with highest **LMP** have most revenue potential Nodes with lowest assigned **network upgrades costs** have most capacity available Nodes where the developer had to **dropout** last time are not viable options for three rounds Nodes with highest **congestion costs** experience the most curtailment Nodes with large amount of wind/solar are good locations for wind/solar resources Nodes where **new transmission** is planned will assign less network upgrade costs to applicant projects and operating projects will experience less curtailment Nodes with large **existing queue** will assign larger network upgrade costs and have longer construction times Node dispatch occurs economically, so nodes which are good for NRIS are good for ERIS as well There is imperfect knowledge of ease of siting and permitting and different developer strategies, so a **randomness factor** is included	Locations for all new projects
ERIS/NRIS	Before applying but after selecting the node location, every project developer gathers the following info from their selected **node:** **ERIS Projects** can use the infrastructure built by connected **NRIS projects** at the same node (free-riding)	NRIS/ERIS status for all new projects Switch requests

	PJM will differentiate (or not differentiate) **Network upgrade cost** assignment and **study time** between NRIS and ERIS consistently round to round Node **LMP** will not change round to round Node **congestion costs** increase with more projects added Before applying but after selecting the node location, every project developer gathers the following info from the **system** level: The **capacity market clearing price** is determined by the intersection of **NRIS generation online** and administratively set demand The assigned study time is the same for all NRIS projects in a round The assigned study time is the same for all ERIS projects in a round The **construction time** for all projects is a function of assigned network upgrade costs Existing projects have a bias to remain as existing **service type**	for any existing projects
Study Period	**Network upgrade costs** are a function of the individual **project's size**, PJM's **(non)differentiation of ERIS and NRIS**, the **cumulative size** of projects submitted to the same node that round, and **node-specific cost function.** Projects dropout when network upgrade costs are higher than their **dropout threshold** Project dropout thresholds are a function of **capacity market prices** (if NRIS), developer **risk tolerance**, **fuel type**, and a random adder to represent unknown factors such as financial liquidity and PPA prices More dropouts result in longer study time because the projects must be restudied The study process has a maximum length that represents the FERC compliant interconnection study length, however, the process can be done more quickly	Total study length time List of projects that succeeded and their NU costs List of projects that dropped out
Construction Period	Construction time is a function of **assigned network upgrade costs**	Constructi on times

		for each project
Capacity Market Auction	Capacity market clears based on the intersection of supply (MW of NRIS resources on the grid) and demand (administratively set by PJM) Queued resources will not be marginal bidders, so their bid prices are not modeled	capacity market price
Congestion	On a daily basis, PJM economically dispatches generation based on **congestion** which is a function of the locations and quantities of supply and demand and available transmission. More transmission build out results in less **congestion** More generation added to node is more **congestion**	Node level congestio n cost representa tion
Electricity Prices(LMP)	LMPs occur at the node level and are a function of the generation bid profile at the node, curtailment, and demand, across the region. For simplification the LMP will remain constant while congestion costs act as a proxy for changes across rounds.	

Appendix C Alternative Reform Scenario 3 and Scenario 4

Reform Scenario 3

In Reform Scenario 3, the PJM RTO shares perfect available capacity information with the project developers, so the developers know where their chances of lower network upgrade costs are likely. Additionally, developers have perfect information on where NRIS project were built so they are able to freeride of the infrastructure NRIS projects paid for.

Table 23: Parameter Changes between Reform 3 and Base Case

Model Parameter	Reform 3	Base Case
ERIS_differentiation	TRUE	FALSE
Reform_3	TRUE	FALSE

Code application

```
Reform_3=True
if self.model.Reform_3 and ERIS_differentiation
        free_ride_factor = min(total_nris / 20, 1)
        if dev.fuel_type=="storage":
            fuel_factor=.1
        if dev.fuel_type=="solar_storage":
            fuel_factor=.1
```

```
            if dev.fuel_type=="solar":
                fuel_factor=.05
            if dev.fuel_type=="wind":
                fuel_factor=.05
        else:
            free_ride_factor=0
            fuel_factor=.04
        eris_prob = base_prob_eris + free_ride_factor+fuel_factor
```

```
if self.model.Reform_3==True:
        score = capacity_score
    else:
        score=(2*size_score+ 1*congestion_score + 2*fuel_bias + nu_score + random_adder+
lmp_score)
```

The hypothesis is that by having better access to information, developers will choose places where they are subsequently assigned fewer network upgrades, however this may also result in more clustering effects, higher dropouts, and higher assigned costs and lower # of projects coming online.

Reform Scenario 4

In reform scenario 4, PJM allows existing ERIS to switch to NRIS at any round, representing ERIS use as a provisional connection service.

Table 23: Parameter Changes between Reform 4 and Base Case

Model Parameter	Reform 3	Base Case
Reform_4	TRUE	FALSE

Code application

Without the reform 4, only developers who have an internal step count of zero may choose a service type. With reform, projects that are already online may switch service types from ERIS to NRIS and go through the study and cost assignment process again, while remaining online as ERIS resources. If they dropout of the study phase, they remain online as ERIS resources. If they complete the study phase, they become NRIS after the assigned construction and study time has passed.

```
def choose_service_type(self):
    past_projects = self.get_past_developer_performance()
    for dev in self.agents_by_type[DeveloperAgent]:
    if Reform_4=True and self.online=True:
        if dev.chosen_node is None:
            continue
    elife dev.internal_step_count == 0:
        if dev.chosen_node is None:
            continue
```

The hypothesis is that by having better access to information, developers will choose places where they are subsequently assigned fewer network upgrades, however this may also result in more clustering effects, higher dropouts, and higher assigned costs and lower number of projects coming online.

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