Reimagining the Queue: Optimization-Guided Generation Interconnection

Emanuel Bernabeu
PJM Interconnection
Audubon, PA
emanuel.bernabeu@pjm.com

Walter Graf
PJM Interconnection
Audubon, PA

Christopher Callagham
PJM Interconnection
Audubon, PA

Amanda Martin
PJM Interconnection
Audubon, PA

Yang Chen
PJM Interconnection
Audubon, PA

William Ulmer
PJM Interconnection
Audubon, PA

***Abstract*— Data center load growth and accelerated generation retirements —driven primarily by policy initiatives— are outpacing the entry of new generation. PJM's generation interconnection process, while rigorous, involves multiple sequential steps, decision points, and re-studies that can extend timelines to as much as 690 days. This paper introduces an optimization-guided framework designed to maximize the amount of new generation that can be accommodated within the existing transmission system without additional network upgrades. The problem is formulated as an optimization using standard power-flow sensitivities (PTDF/DFAX), clustering projects into *Tier 1* (no-upgrade) and *Tier 2* (upgrade-dependent) groups. A proof-of-concept demonstrates that material generation capacity can be interconnected with zero incremental reinforcement cost, potentially reducing the time required to move from queue entry to construction.**

It is tempting—and easy—to blame the interconnection queue for the current supply–demand imbalance. As of mid-2025, more than 46 GW of cleared projects remain unbuilt due to supply-chain, permitting, financing, and policy challenges. This framework addresses one critical element within that broader landscape of delayed new entry.

Keywords*— *generation interconnection, transmission planning, optimization.

I. Introduction

The electric power industry is undergoing a rapid transformation driven by the convergence of five intertwined trends: (a) rapid load growth from data centers and electrification, (b) accelerated retirement of thermal resources—driven primarily by policy objectives, (c) slow entry of new generation resources, (d) transition toward inverter-based generation, and (e) a broad increase in uncertainty and risk stemming from policy, climate, and geopolitical factors.

In 2023, PJM's report [1] highlighted the growing resource adequacy risk caused by a mismatch between load growth, retirements, and new generation entry, projecting potential capacity shortfalls by 2028–2030. Those projections have since begun to materialize, leading to tightening resource adequacy margins. The capacity market is now sending strong price signals—clearing at its cap—to incentivize new entry.

The generation interconnection queue is an important piece of this puzzle. To address a growing backlog and stakeholder concerns about study timelines, PJM launched a major reform of its generation interconnection process in 2023. The new *first-ready, first-served* framework introduced clustered studies, strengthened milestone requirements, and improved coordination with transmission owners. These reforms have yielded measurable results: since 2023, PJM has processed approximately 140 GW of projects and reduced the transition backlog to about 63 GW as of mid-2025 [2]. PJM now targets one- to two-year study timelines for new projects.

However, clearing the queue does not necessarily translate to steel in the ground. As of mid-2025, more than 46 GW of projects with signed interconnection agreements remain unbuilt. Developers cite permitting delays, supply-chain constraints, financing costs, and policy uncertainty as dominant causes.

Significant research has examined the coordination of generation, transmission, and fuel systems using optimization-based planning frameworks. Prior work includes integrated electricity–natural-gas expansion planning models [3-4], co-optimized transmission and distribution planning [5-6], and expansion models that jointly capture operational flexibility and renewable targets [7-8]. Within competitive market contexts, several studies have explored strategic generation expansion decisions and decentralized investment behavior [9-10]. More recently, the literature has begun to recognize the material impact of interconnection queues on long-term planning outcomes [11-12].

This paper introduces an optimization-guided framework designed to complement existing interconnection procedures. The premise is deceptively simple: *What is the maximum amount of new generation that can be accommodated by the grid without the need for additional network upgrades?* Intuitively, generation with zero network-upgrade cost can proceed immediately to agreement and construction, independent of other transmission expansion work.

The remainder of this paper is organized as follows. Section II describes the current interconnection process and outlines its analytical and procedural challenges. Section III presents the formulation of the optimization-guided framework and potential extensions. Section IV provides analytical results. Section V concludes with a summary of findings.

II. Motivation

The grid is not governed by physics alone; it is a complex ecosystem balancing markets, policy, planning, investment, and risk. Within this ecosystem, re-imagining the interconnection queue offers a promising avenue for innovation.

A. *Background & Current Process*

Projects enter the interconnection queue through a defined cycle and are studied in batches. For each cycle, PJM develops a base power-flow case representing forecasted load, committed generation, and approved transmission upgrades. Clusters of projects are then injected into this case to evaluate post-contingency thermal, voltage, short-circuit, and stability performance. When violations occur, PJM and the affected Transmission Owners (TOs) identify the upgrades required to relieve those constraints. These upgrades and their estimated costs are allocated to contributing projects using Distribution Factors (DFAX). Enforcing cost causality is a strength of the existing process: it isolates load from generation investment decisions and, in principle, encourages developers to interconnect where the system has available headroom.

The sequential nature of the process is illustrated in Fig. 1. At each decision point, a project may continue or withdraw from the queue. Withdrawals trigger updates to the power-flow case, re-study for remaining projects, re-identification of overloads, revised upgrade estimates from TOs, and updated cost allocations.

B. *The Problem of Phantom Constraints*

It is well understood that only a fraction of projects in the interconnection queue ultimately reach construction. However, at the beginning of each cycle, all projects must be treated as feasible. To put things into perspective, the total queued capacity for a cycle can exceed 40,000 MW. Intuitively, stacking so much generation into the grid leads to a large number of overloads. These phantom overloads – physically real, but in practice unlikely to materialize – lead to significant transmission upgrades and inflated cost estimates that may discourage viable projects in the early phases of the process.

The queue behaves as a sequential, non-cooperative decision process in which each project's withdrawal or continuation alters cost allocations – and therefore viability – for all other participants. If a project withdraws, the associated upgrade costs can shift to the remaining participants — the cost increase can prompt additional withdrawals (like a domino effect). Conversely, withdrawals can also eliminate phantom overloads, reducing or removing upgrade costs for other projects. Developers may decide to remain in the queue, even when initial upgrade costs appear high, in anticipation that subsequent withdrawals may lower their costs.

This phenomenon can be observed in PJM's Transition Cycle 1 (2025). Nine projects that had zero network-upgrade costs in Phase-1 were assigned up to \$18 million in Phase-2, while nine other projects that initially faced up to \$11 million in Phase-1 had zero cost in Phase-2. It is important to emphasize that these interim estimates are informational; only the final interconnection agreement establishes binding cost.

In summary, phantom constraints introduce several structural challenges into the interconnection process. Viable projects can appear uneconomic in early phases because upgrades driven by the unlikely "all-in" combination of projects produce large, front-loaded cost estimates. Cost discovery unfolds slowly across multiple study phases, and cost allocations can shift materially as projects are modified or withdrawn. Transmission owners must repeatedly re-evaluate upgrades and associated cost estimates, which is one of the primary drivers of extended study timelines, and a substantial portion of early analytical work is ultimately discarded.

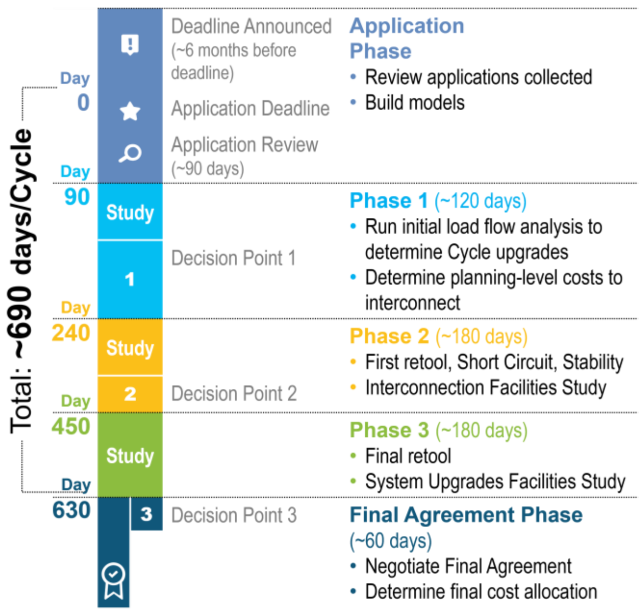

Fig. 1 PJM's generation interconnection queue process.

Taken together, these effects—combined with the urgency to increase the pace of new generation entry—motivate the exploration of methods that identify system-level optimal project combinations in a single step rather than through an iterative process.

III. Methodology: An Optimization-Guided Framework

This section introduces a Mixed-Integer Programming (MIP) formulation to identify the maximum amount of new generation that can be accommodated within the existing transmission system without causing any thermal overloads. The solution naturally partitions queued projects into two groups: (i) those that can interconnect with zero network-upgrade cost (*Tier-1*), and (ii) those whose injections would require system reinforcements (*Tier-2*).

A. *MIP Formulation*

The formulation of the objective function and constraints used in the optimization is as follows:

$$max \sum_j P_j \cdot x_j \tag{1}$$

$$Subject\ to:$$

$$|F_{i,k}^{base} + \sum_j DFAX_{i,j,k} \cdot P_j \cdot x_j \,| \le F_i^{limit} \quad \forall i,k \tag{2}$$

$$x_j \in \begin{cases} 1 & if\ generator\ j\ is\ selected \\ 0 & otherwise \end{cases} \quad \forall j \tag{3}$$

Where,

P_j *is the MW injection of generator j* (4)

$DFAX_{i,j,k}$ *is linearized sensitivity of element i's flow to an injection at generator j* (5)

$F_{i,k}^{base}$ *is the base case flow on element i under continency k* (6)

$F_{i,k}^{limit}$ *is the rating of element i* (7)

Distribution Factors (DFAX) are a linear approximation to the change in power flow through the network given an injection (positive or negative) at a particular node [13]. Incremental injections are balanced using generator participation factors. DFAX values are widely known and commonly used across numerous power system applications (economic dispatch, N-1 contingency analysis, etc). Incidentally, the first application of DFAX on the PJM Interconnection goes all the way back to 1961 [14].

Consistent with industry practice, the optimization results are validated using full AC power-flow solutions to ensure that feasibility is preserved beyond the linear approximation.

B. Reimagining the Interconnection Queue: Conceptual Framework

The stakeholder process is PJM's strongest asset. Robust solutions are developed by incorporating insights from all sectors of the industry, including load, developers, transmission owners, and policy representatives. The exact shape and form of a reimagined interconnection process that incorporates this MIP formulation is beyond the scope of this paper; rather, this section outlines a conceptual framework and highlights its potential advantages.

The MIP solution naturally partitions projects into two groups with distinct pathways:

- **Tier-1 (no-upgrade):** Projects in this set satisfy all thermal constraints under all modeled contingencies without requiring network reinforcements. Conceptually, Tier-1 projects could proceed directly to interconnection agreement execution.
- **Tier-2 (upgrade-dependent):** These projects would follow a DFAX-based cost allocation framework similar to the current process. The optimization also enables a natural extension into sub-tiers within Tier-2. By relaxing individual binding constraints in the MIP—analogous to allocating an "upgrade budget"—additional tranches of feasible generation can be identified. This produces a structured sequence of incremental sub-tiers, each representing combinations of projects enabled by a specific reinforcement or set of upgrades.

This framework offers several advantages. First, the optimization performs in a single pass what the current process achieves through multiple iterations. The three study phases and intermediate decision points used today to filter projects are replaced by a single optimal solution. This reduces PJM's analytical burden and alleviates the number of times transmission owners must design reinforcements and estimate upgrade costs.

Second, the formulation organically alleviates the problem of phantom constraints while efficiently exploiting available transmission capacity. The resulting Tier-1 set identifies the subset of queued generation that can interconnect immediately under the existing transmission topology, without reliance on the assumed "all-in" queue case used in early study phases. By optimizing the use of existing headroom—analogous in spirit to the goals of grid-enhancing technologies—the method extracts additional capability from the current system before requiring new network upgrades.

Third, the optimization provides fast cost discovery and certainty for Tier-1 projects, which have zero network-upgrade responsibility by construction. This eliminates the cost volatility associated with sequential re-studies, in which upgrade allocations may change materially as the project set evolves.

Finally, because Tier-1 projects can proceed directly to interconnection agreement execution and are not dependent on the timeline of transmission expansion, the framework can potentially accelerate the pace of new construction. The absence of required upgrades also reduces the volume of construction outages that must be scheduled around ongoing system operations, which has become increasingly challenging as transmission expansion has accelerated.

Short-circuit and stability studies would be performed after the Tier-1/Tier-2 determination. In today's process, generators are responsible for any stability-driven upgrades; however, given their historically low incidence, stakeholders could consider a separate treatment for these rare cases to avoid reintroducing study iterations.

C. Organic Extensions of the Framework

Several natural extensions can be incorporated into the presented framework without altering the underlying structure of the model.

In the basic formulation, any project that causes a violation is excluded from Tier-1. However, developers may be willing to fund a limited amount of network reinforcements in exchange for interconnection certainty and speed. This can be represented in the optimization by assigning each generator a willingness-to-pay parameter or by introducing an upgrade budget constraint. Under this extension, the optimization would admit combinations of projects whose aggregate DFAX-based upgrade requirements fall within a specified expenditure limit. This provides a mathematically transparent approach for defining Tier-2 sub-tiers, each corresponding to incremental reinforcements that expand the set of feasible generators.

The framework also accommodates weighted megawatt objective function, enabling alignment with policy or system-planning priorities. For example, the objective function may weight a project's MW contribution by factors like those used in PJM's Reliability Resource Initiative (RRI) scoring framework (e.g., UCAP value, ELCC contribution, in-service date, zonal need, or project development maturity) [15]. This allows the optimization to favor projects that contribute more to reliability, flexibility, or policy objectives, while still respecting all thermal constraints.

Beyond project selection, the optimization structure can also support the discovery of strategic transmission reinforcements that enable larger sets of Tier-1 projects. By examining the binding constraints in the MIP solution—or systematically relaxing them—the model highlights specific transmission elements and corridors whose upgrades unlock the greatest increase in deliverable generation. This provides a quantitative "middle ground" between (i) PJM's current practice of conducting transmission planning primarily for load growth, and (ii) the "build-it-and-they-will-come" approach used by other RTOs [16].

IV. SIMULATION RESULTS

A. Benchmarking Against Transition Cycle 1(2025) Results

The proposed methodology is benchmarked against PJM's Transition Cycle 1 (2025), which included 303 projects—representing a total of 44.5 GW—and approximately 10,000 N-1 contingencies. The full Eastern Interconnection model

979-8-3315-8138-1

was used, with PJM representing approximately 25,000 buses. The optimization identifies:

- **Tier-1:** 62 projects (no-upgrade), totaling 7,868 MW
- **Tier-2:** 241 projects (upgrade-dependent), totaling 36,681 MW

In contrast, the Transition Cycle 1 Phase-3 study identified only 70 MW of generation with zero network-upgrade cost. The optimization therefore identifies two orders of magnitude more zero-upgrade interconnection potential by exploiting existing transmission headroom.

To build intuition for this difference, Fig. 2 shows the evolution of upgrade-cost estimates across the three phases of Transition Cycle 1. The 65% reduction—from $13.1 billion in Phase-1 to $4.6 billion in Phase-3—does not reflect any changes in the physical system; rather, it reflects project withdrawals that progressively removed phantom overloads. The proposed method bypasses these steps and directly identifies the largest feasible subset of projects that do not trigger thermal upgrades.

Transition Cycle 1 ultimately approved 128 projects totaling 17.4 GW, and $4.6 billion dollars of network upgrades, pending finalized interconnection agreements. To approximate this outcome, binding constraints in the optimization were systematically relaxed, analogous to introducing targeted reinforcements. This stepwise relaxation forms the basis of the proposed Tier-2 sub-tier structure. Fig. 3 shows cumulative generation enabled as a function of the number of relaxed constraints (i.e., network upgrades). The interconnection of 17.2 GW of generation requires 112 projects—62 from Tier-1 and 50 from Tier-2—and 35 network upgrades.

Fig. 4 provides additional insight by comparing the thermal ratings of the required upgrades against the empirical distribution of existing 115 kV, 230 kV, 500 kV line ratings. Most reinforcements target lower-voltage facilities, consistent with the congestion patterns identified in the optimization. Fig. 5 offers an alternative perspective by plotting cumulative interconnection as a function of the thermal rating of the relaxed constraint. This representation highlights how a willingness-to-pay or upgrade-budget construct could be incorporated: since upgrade costs generally scale with voltage level and facility rating, relaxing higher-rated constraints corresponds to increasingly costly reinforcements.

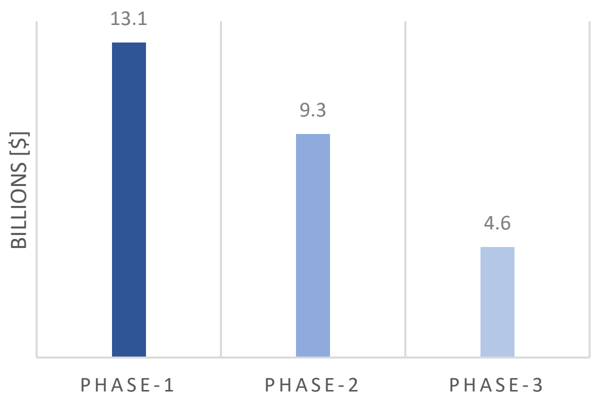

Fig. 2. Evolution of upgrade-cost estimates across the three phases of Transition Cycle 1 (2025).

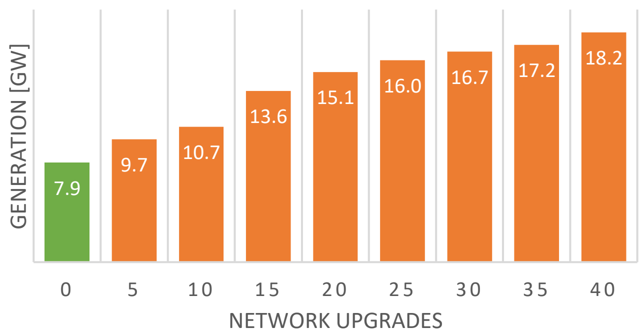

Fig. 3. Cumulative Tier-2 generation interconnection as a function of network upgrades.

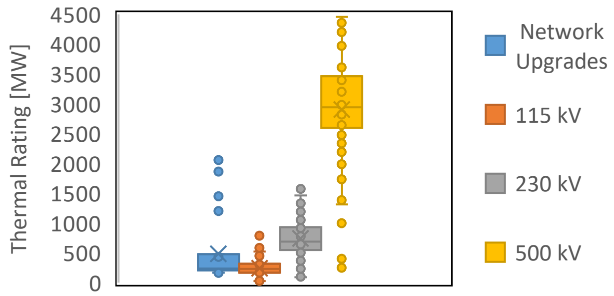

Fig. 4. Boxplot comparing thermal ratings of binding constraints and 115 kV, and 230 kV transmission lines.

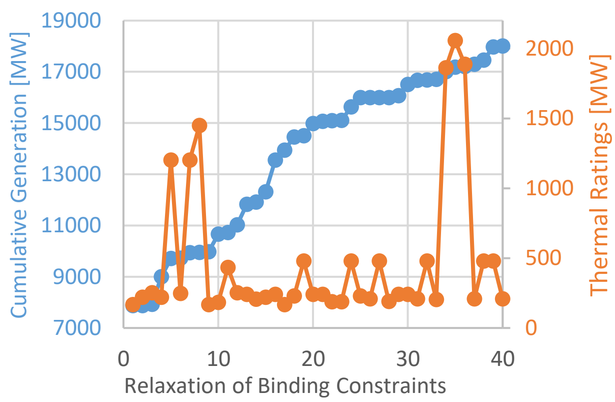

Fig. 5. Sequential relaxation of binding constraints versus cumulative generation interconnection.

B. Robustness under Tier-1 Withdrawals

Although Tier-1 generators have zero network-upgrade costs, some projects may still withdraw due to permitting, financing, or supply-chain constraints. During Transition Cycle 1 (2025), late withdrawals triggered additional analysis and altered upgrade requirements, demonstrating that this sensitivity is present in the current process.

A Monte-Carlo experiment was performed to assess the robustness of the Tier-1 portfolio under potential withdrawals. The experiment proceeds in two steps:

1. Random number of withdrawals: For each trial, a random integer between 1 and 62 (the total number of Tier-1 projects) is drawn to represent the number of assumed withdrawals.
2. Random selection of withdrawn projects: The corresponding number of projects is then uniformly sampled, with replacement, from the Tier-1 set.

979-8-3315-8138-1

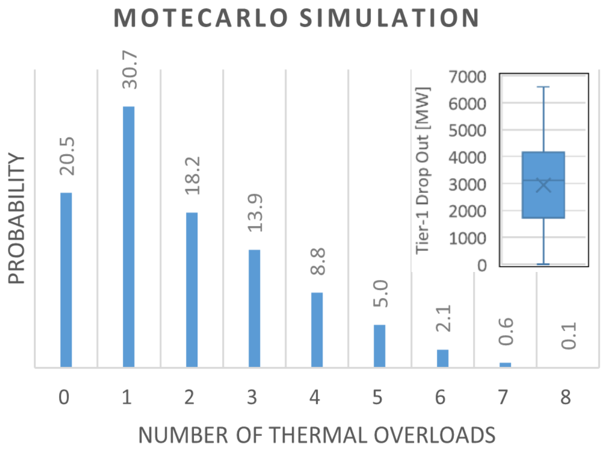

Fig. 6 Monte-Carlo simulation shows the probability of thermal overloads using 10000 replications of random project dropouts from Tier-1.

Fig. 6 summarizes the results from 10,000 replications. Overall, there is approximately a 70% probability of observing two or fewer thermal overloads if projects from Tier-1 withdraw. The boxplot on the left illustrates the cumulative MW withdrawn per trial; the median exceeds 3,000 MW, reflecting the intentionally pessimistic nature of this experiment.

Sensitivity to late withdrawal is not unique to the optimization-guided framework; it already exists under the current interconnection process. The Monte-Carlo analysis simply makes this effect explicit and quantifiable. These results can help inform the design of potential backstop mechanisms for rare residual overloads (e.g., treatment through the Regional Transmission Expansion Plan (RTEP)).

V. Conclusion

This paper introduced an optimization-guided approach for identifying the maximum amount of new generation that can interconnect without thermal upgrades. Applied to PJM's Transition Cycle 1, the method identified 7.868 GW of zero-upgrade interconnection potential —compared to 70 MW under the current study process. The formulation also provides a structured path for upgrade-dependent projects through incremental relaxation of binding constraints, yielding a transparent Tier-2 sub-tier structure.

More broadly, the approach offers a one-shot alternative to the existing sequential process. The formulation is flexible and extensible, supporting weighted objective functions, willingness-to-pay parameters, and the identification of strategic reinforcements that enable additional entry.

A Monte-Carlo assessment showed that sensitivity to late project withdrawals is an inherent feature of any generation interconnection construct; the optimization simply makes this effect explicit and quantifiable.

Taken together, these results demonstrate that the proposed methodology provides a credible foundation for reimagining the interconnection queue—improving study speed, cost discovery, and the effective utilization of the existing grid, while maintaining reliability and transparency.

VI. References

[1] PJM, "Energy Transition in PJM: Resource Retirements, Replacements & Risks" , https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/energy-transition-in-pjm-resource-retirements-replacements-and-risks.pdf, February 2023.

[2] PJM, "Interconnection Reform Progress", https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/interconnection-reform-progress-fact-sheet.pdf, June 2025.

[3] G. Huang, F. Wen, M. A. Salam, Z. Dong, Y. Zheng and R. Zhang, "Optimal collaborative expansion planning of integrated electrical and natural gas energy systems," 2016 IEEE Innovative Smart Grid Technologies - Asia (ISGT-Asia), Melbourne, VIC, Australia, 2016, pp. 378-383.

[4] C. Unsihuay, J. W. Marangon-Lima and A. C. Z. de Souza, "Integrated Power Generation and Natural Gas Expansion Planning," 2007 IEEE Lausanne Power Tech, Lausanne, Switzerland, 2007, pp. 1404-1409

[5] S. Borozan and G. Strbac, "Multi-Stage Integrated Transmission and Distribution Expansion Planning Under Uncertainties With Smart Investment Options," in IEEE Transactions on Sustainable Energy, vol. 16, no. 1, pp. 546-559, Jan. 2025

[6] W. R. Faria, G. Muñoz-Delgado, J. M. Arroyo, J. Contreras and B. R. Pereira, "Accelerated Benders Decomposition for Enhanced Co-Optimized T&D System Planning," in IEEE Transactions on Power Systems, vol. 40, no. 3, pp. 2297-2309, May 2025

[7] E. Raycheva, J. Garrison, C. Schaffner and G. Hug, "High Resolution Generation Expansion Planning Considering Flexibility Needs: The Case Of Switzerland In 2030," The 12th Mediterranean Conference on Power Generation, Transmission, Distribution and Energy Conversion (MEDPOWER 2020), Online Conference, 2020, pp. 416-421

[8] A. Moreira, D. Pozo, A. Street and E. Sauma, "Reliable Renewable Generation and Transmission Expansion Planning: Co-Optimizing System's Resources for Meeting Renewable Targets," in IEEE Transactions on Power Systems, vol. 32, no. 4, pp. 3246-3257, July 2017

[9] A. J. C. Pereira and J. T. Saraiva, "Generation Expansion Planning in Competitive Electricity Markets," 2007 IEEE Lausanne Power Tech, Lausanne, Switzerland, 2007, pp. 897-902

[10] A. L. M. Marcato et al., "Genetic Algorithm Approach Applied to Long Term Generation Expansion Planning," 2006 IEEE/PES Transmission & Distribution Conference and Exposition: Latin America, Caracas, Venezuela, 2006, pp. 1-7

[11] E. Glista and J. -P. Watson, "Electricity Grid Capacity Expansion Planning Considering Interconnection Queue Uncertainty," 2024 18th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), Auckland, New Zealand, 2024, pp. 1-6

[12] Xie Min, Chen Jinfu and Duan Xian Zhong, "Generator maintenance scheduling in the generation expansion planning of interconnected power system," IEEE/PES Transmission and Distribution Conference and Exhibition, Yokohama, Japan, 2002, pp. 1601-1605.

[13] A. Wood and B. Wollenberg, "*Power Generation, Operation and Control*". New York: Wiley, 1996.

[14] C. A. Macarthur, "Transmission Limitations Computed by Superposition," in *Transactions of the American Institute of Electrical Engineers. Part III: Power Apparatus and Systems*, vol. 80, no. 3, pp. 827-831, April 1961, doi: 10.1109/AIEEPAS.1961.4501149

[15] PJM, "Reliability Resource Initiative – Summary Results", https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf, May 2025.

[16] W. P. Lasher, "The development of competitive Renewable Energy Zones in Texas," *2008 IEEE/PES Transmission and Distribution Conference and Exposition*, Chicago, IL, USA.

979-8-3315-8138-1