Illinois' 2025 Draft Renewable Energy Access Plan

Prepared for the Illinois Commerce Commission

December 2025

Prepared by:
The Illinois Commerce Commission Staff and Energy and Environmental Economics, Inc.

TIMING AND STATUS OF THE 2025 DRAFT RENEWABLE ENERGY ACCESS PLAN

This draft of the Renewable Energy Access Plan has been prepared by the ICC staff and Energy and Environmental Economics, Inc. for submission to the Illinois Commerce Commission. ICC staff will submit this draft with a Staff Report requesting that the Commission open a docketed investigation to develop and adopt a Renewable Energy Access Plan (REAP or Plan).

CONTRIBUTING AUTHORS (IN ALPHABETICAL ORDER)

The Illinois Commerce Commission Staff

Zachary Callen, Torsten Clausen, Hannah McCorry, Toba Pearlman, James Zolnierek

THIS DRAFT REAP WAS PREPARED WITH SUPPORT FROM THE FOLLOWING CONSULTANT TEAMS

Energy and Environmental Economics, Inc.

Lakshmi Alagappan, Charlotte Fagan, Samuel Schreiber, Alankar Sharma, Laura Shi, Kevin Steinberger, Thomas Strnad, Vignesh Venugopal, Parker Wild

Viridis Consulting, LLC

Zach Alter, Doug O’Connor, Sophie Gaston, Mabell Garcia Paine, Rae Lynn Schneider

2IM Group, LLC

Dennis Kasner, Lisa Nielsen, Erik Salazar

ACKNOWLEDGEMENTS

The ICC staff are grateful to the Illinois Power Agency, the Illinois Environmental Protection Agency and the Illinois Department of Natural Resources for their input and support through the analytical work and writing of this report. The ICC staff thanks the U.S. Department of Energy’s Pacific Northwest National Laboratory for their support with data collection and development of preliminary weighted “suitability” scores across the state to be described in Chapter 3. The ICC staff also thanks all stakeholders who participated and provided feedback in five public workshops, one community outreach webinar and two technical working group meetings held in 2025 to be detailed in Chapter 1.

Table of Contents

Table of Figures

Table of Tables

Acronym Definitions

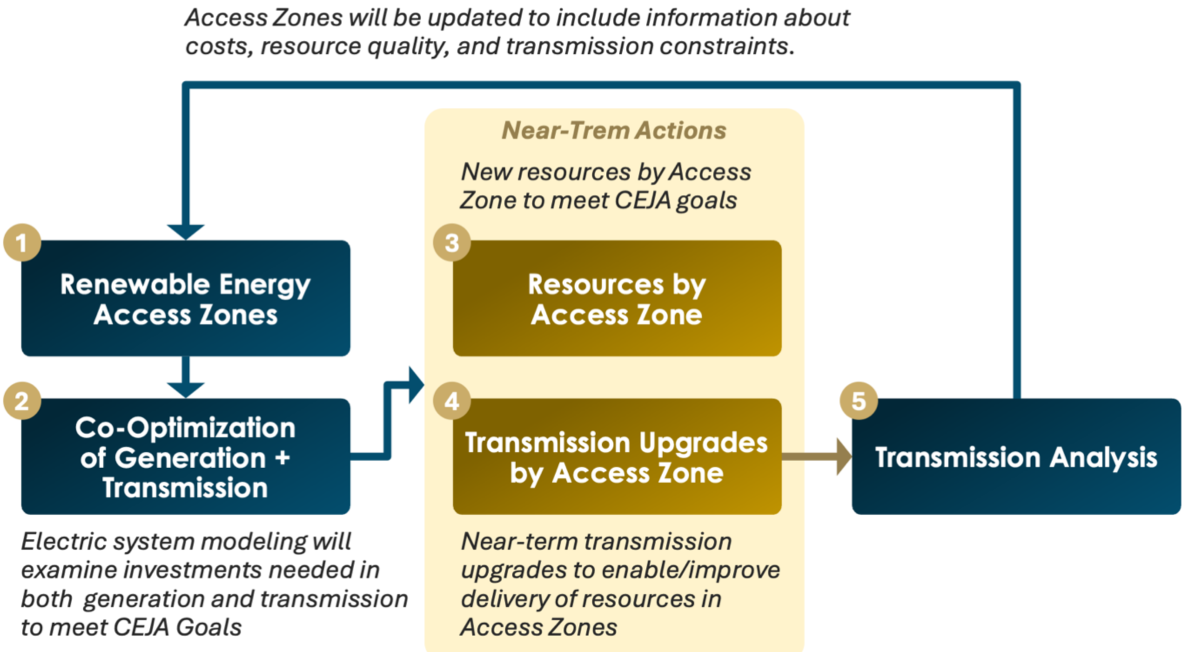
Acronym	Expanded Form
APFC	Advanced Power Flow Controller
ATT	Advanced Transmission Technologies
BOS	Balance of System
CapEx	Capital Expenditure
CEJA	Climate and Equitable Jobs Act
CETL	Capacity Emergency Transfer Limit
CMC	Carbon Mitigation Credit
CONE	Cost of New Entry
CRGA	Clean and Reliable Grid Affordability Act (Illinois SB 25)
DER	Distributed Energy Resource
DLR	Dynamic Line Rating
EJ	Environmental Justice
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency
ERAS	Expedited Resource Addition Study
EV	Electric Vehicle
FEJA	Future Energy Jobs Act
FEOC	Foreign Entity of Concern
FERC	Federal Energy Regulatory Commission
GW	Gigawatt
ICC	Illinois Commerce Commission
IOU	Investor-Owned Utility
IPF	Integrated Planning Framework
IPA	Illinois Power Agency
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
JTIQ	Joint Targeted Interconnection Queue
kW	Kilowatt

kWac	Kilowatts AC
Li-ion	Lithium-ion
LBNL	Lawrence Berkeley National Lab
LRZ	Local Resource Zone
LTRRPP	Long-Term Renewable Resources Procurement Plan
MISO	Midcontinent Independent System Operator
MW	Megawatt
NREL	National Renewable Energy Lab
NWA	Non-Wires Alternative
OMS	Organization of MISO States
PA	Public Act
PJM	PJM Interconnection, LLC
PTC	Production Tax Credit
PUA	Public Utilities Act
RA	Resource Adequacy
RA Study	Resource Adequacy Study
REAP	Renewable Energy Access Plan
REC	Renewable Energy Credit / Certificate
RMR	Reliability Must-Run
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SATOA	Storage-as-Transmission-Only Asset
SB	Senate Bill
SPP	Southwest Power Pool
TWh	Terawatt-hour
ZEC	Zero Emission Credit
ZIA	Zonal Import Ability

Executive Summary

Illinois' 2025 Draft Renewable Energy Access Plan (REAP) builds on the foundation established in the 2024 REAP and responds to significant shifts in regional markets, policy, and federal transmission planning requirements. The REAP is organized into five Strategic Elements and outlines recommendations for enabling a reliable, affordable, and equitable transition towards meeting the Climate and Equitable Jobs Act (CEJA) legislative requirements, goals, and objectives. This REAP incorporates updated data, expanded modeling, and insights from eight stakeholder engagements held throughout 2025. One of the most significant achievements of this REAP cycle is developing an Integrated Planning Framework (IPF), as shown in the figure below. The development of this framework allows the Illinois Commerce Commission (ICC) to identify the generation and transmission needs to achieve the state's policy targets, and it can inform state advocacy in regional planning processes. The assumptions and analysis performed in each step of this framework will continue to be refined in future REAP cycles to ultimately support Illinois' identification of "least-regret" actions.

Figure ES 1: Integrated Planning Framework Overview



A major technical achievement of this REAP cycle is the development of the modeling architecture underpinning the IPF. For the first time, Illinois has developed a unified analytical platform that simultaneously models both Regional Transmission Organizations (RTOs) that Illinois is a part of – the Midcontinent Independent System Operator (MISO) and the PJM Interconnection (PJM). It maps REAP zones within Illinois to the electricity system topology and evaluates least-cost transmission and generation portfolios across both MISO and PJM service territories within Illinois to maintain reliability and meet Illinois policy targets. Producing a consistent, statewide view of resource needs in two different markets and planning regimes is challenging; this REAP provides a foundation for doing so that can directly inform state positions on interconnection, transmission, and market design proceedings for years to come. This cycle provides the proof of concept for linking renewable siting, RTO-specific deliverability constraints, and proactive headroom assessment within a single planning construct, and enables future REAP cycles to be iteratively more detailed and specific, leading to increasingly actionable results.

Key advancements in the 2025 Draft REAP include:

- Expanding stakeholder engagement, including through the establishment of a Technical Working Group and a Community Engagement process
- Developing an Integrated Planning Framework that enables the state to identify least-cost portfolios of investment in generation and transmission infrastructure
- Examining key considerations among various regulatory pathways to advance projects that meet REAP needs
- Exploring the potential role of Advanced Transmission Technologies and Non-Wires Alternatives in addressing transmission system needs identified by the REAP

This REAP also breaks new ground in establishing a practical framework for evaluating Advanced Transmission Technologies (ATTs) and Non-Wires Alternatives (NWAs) based on their avoided costs, operational value, and their ability to defer or right-size larger investments. Combined with clear recommendations on interconnection reform, joint RTO coordination, and regulatory pathways, the REAP positions Illinois to proactively advocate for pathways that support solutions to REAP-identified needs within respective RTO processes. Rather than reacting to regional planning outcomes, Illinois now has the analytical toolkit needed to influence them, aligned with its goals of ensuring that future transmission portfolios better reflect state policy targets, siting considerations, and cost-effectiveness for Illinois consumers.

Strategic Element	Commission Directive from the 2024 REAP Order	Actions Taken in this REAP Cycle	Anticipated Actions in the Next REAP Cycle in Support of Ongoing Progress toward Commission Directives
1. Tracking Progress Toward Illinois' Policy Goals	Track and report on progress towards clean energy requirements Conduct community outreach and stakeholder engagement Evaluating progress with RTOs, stakeholders and utilities	Strategic Element 1 reports on progress towards CEJA targets, developed in collaboration with other Illinois State Agencies. The ICC hosted 5 stakeholder workshops, 2 technical working group meetings and one community engagement webinar this REAP cycle. Additional recommendations for further stakeholder engagement can be found in Strategic Element 1. The ICC has met regularly with RTO staff and utilities on progress.	The REAP will continue to report on progress towards Illinois policy goals, highlighting any anticipated risks to policy achievement. Enhanced stakeholder engagement contributed substantial value this REAP cycle, and ICC will continue to host a variety of stakeholder forums next cycle. ICC will continue to improve community engagement to broaden involvement in the REAP. The ICC will continue to work closely with RTO and utility stakeholders.
2. Transitioning to a Decarbonized Electricity Mix	Electrification Strategy Study fossil generations' operations and reliability in EJ communities	An Integrated Planning Framework discussed in Strategic Element 2 was built to examine resource and transmission needs in different scenarios. The modeling capability was then demonstrated using three scenarios that all maintain statewide reliability, meet the CEJA *legislative requirements* of 50% RPS, and phase out emissions from large in-state fossil generation. A workshop on scenario design was organized to get stakeholder input on high-impact-high-uncertainty factors that should be considered in future REAP cycles.	The Integrated Planning Framework enables the ICC to study a variety of scenarios in the next cycle. These scenarios could include a variety of electrification strategies to meet the CEJA goal of 100% clean energy by 2050. The State's Resource Adequacy Study (RA Study) is underway in parallel with this 2025 Draft REAP and contains a more detailed reliability assessment. Since the RA Study and REAP both utilize a common modeling framework, findings from the RA Study will be incorporated into the next REAP and analysis will continue into the future.

3. Managing Land Use in Renewable Deployment	Refine REAP zones	Strategic Element 3 explores how REAP zones boundaries were refined this cycle to make them more actionable. Strategic Elements 2 and 3 also describe preliminary modeling efforts and results showing infrastructure builds by REAP zone in three scenarios.	The next REAP cycle will continue to refine REAP zones, including through an assessment of the suitability of land for infrastructure development in each REAP zone, leading to updated cost and potential estimates. These refined assumptions will then feed into additional scenario analysis described above.
4. Effective Transmission Planning & Utilization	Study alternatives to transmission	Strategic Element 4 explores advanced transmission technologies and non-wire alternatives, including putting forth a framework to evaluate alternatives on an avoided cost basis.	The next cycle will explore ways to evaluate advanced transmission technologies as part of the Integrated Planning Framework.
5. Leveraging Regional Processes and Markets	Advocate for interconnection and transmission planning reform Leveraging Regional Markets Assess GHG Leakage	The ICC has taken steps to advocate for interconnection and transmission reform as outlined in the Introduction to the 2025 Draft REAP. Strategic Element 5 discusses how Illinois state policy maps onto regional market roles and how to leverage regional processes and markets to achieve REAP goals. The "No Net Imports" scenario in Strategic Element 2 illustrates the impact of requiring the state's effective capacity need to be met entirely with clean resources in-state and requiring all imports to be offset with clean energy exports on an annual basis. Strategic Element 5 discusses GHG border pricing.	The ICC will continue to advocate for interconnection and transmission reform as guided by the 2024 Order and any additional directives from the Commission this cycle. In the next cycle, the Integrated Planning Framework enables the ICC to study additional scenarios that capture GHG leakage issues and that explore different strategies to minimize leakage.

Strategic Element 1: Tracking Progress Toward Illinois' Policy Goals

Illinois has continued to make measurable progress toward the clean-energy and emissions-reduction commitments established under CEJA. **Renewable energy procurement has expanded through the Illinois Power Agency (IPA) programs, with nearly 3 GW of utility-scale projects energized and more than 5.6 GW under development, alongside steady growth in distributed generation and community solar.** Fossil generation emissions have continued to decline: CO_2 emissions from the electric sector fell by over 20% between 2021 and 2024, and several large coal and gas units are expected to retire prior to the first mandatory phase-out dates. Electrification programs have accelerated adoption of electric vehicles (EVs) and building electrification measures, with utilities implementing new Beneficial Electrification Plans to support charging infrastructure and customer incentives. While this trajectory aligns with CEJA's long-term direction, the analysis also underscores the scale of work still ahead. **Rapid load growth from data centers and electrification continues to revise upward the amount of clean supply required to meet CEJA goals,** which subsequently requires increased renewable and clean energy resource deployment to meet targets and total supply needs.

Strategic Element 1 also explores how the ICC expanded its stakeholder engagement approach in this REAP cycle to ensure transparent, inclusive, and data-informed planning. Eight stakeholder engagement events, including five stakeholder workshops, two technical working groups, and a community outreach webinar, provided forums for developers, utilities, advocacy groups, and community organizations to provide input on REAP zones, modeling assumptions, scenario design, land-use considerations, regional coordination, and future community engagement priorities. Stakeholders emphasized the importance of reliability considerations, siting and permitting challenges, coordination between MISO and PJM, consideration of Advanced Transmission Technologies (ATTs), Non-Wires Alternatives (NWAs), and the importance of alignment between state agencies.

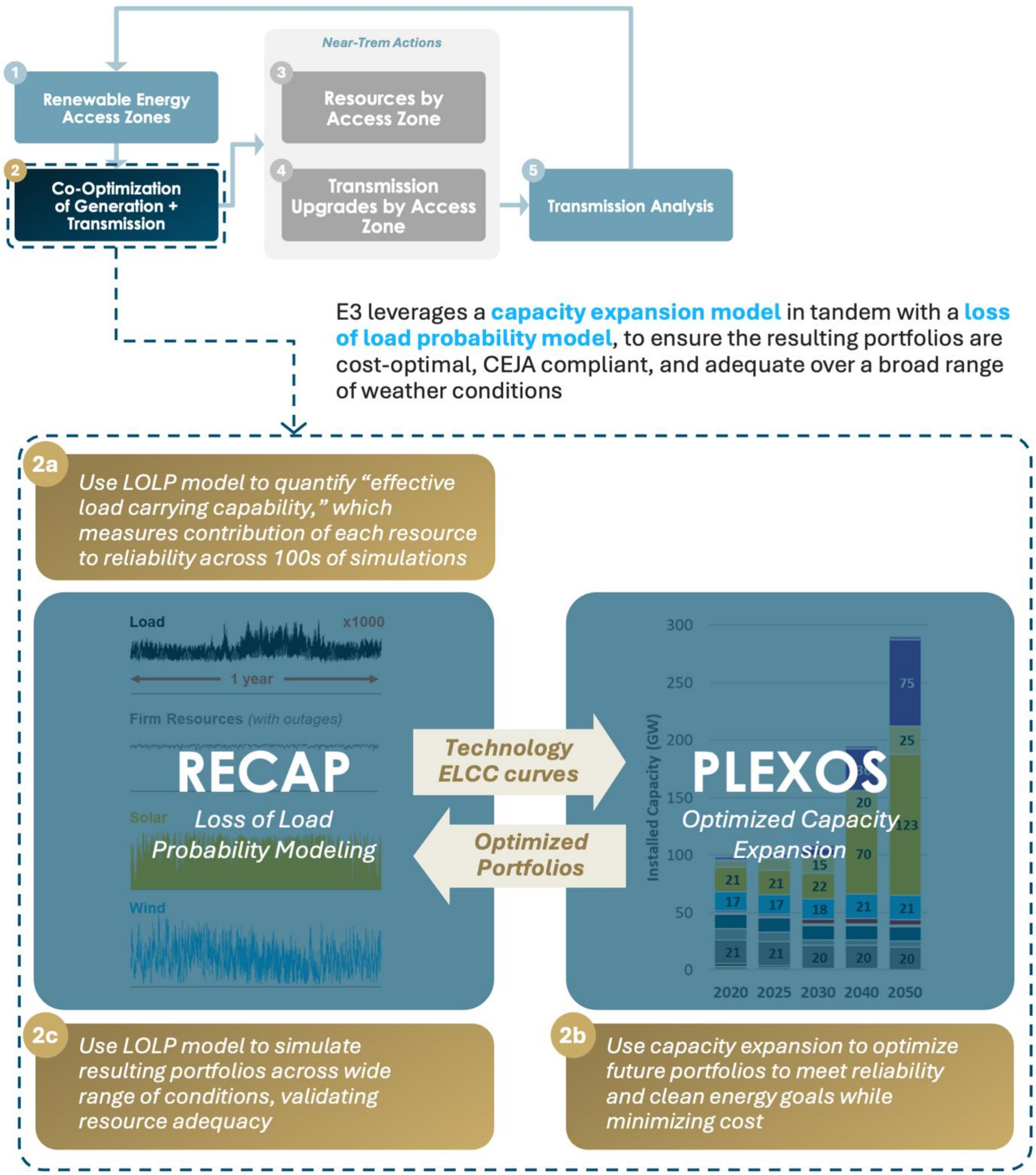
Reflecting the lessons from this REAP cycle, the chapter recommends several steps to continue monitoring progress and strengthening future stakeholder processes.

Strategic Element 1 Recommendations
+ Continued tracking of Illinois' progress towards state policy targets amid an evolving landscape enables early identification of risks, such as data-center driven demand growth, that could challenge CEJA compliance.
+ The next REAP should continue building stakeholder engagement through stakeholder workshops and the technical working group.
+ The next REAP cycle should further build out a community engagement strategy, building on this REAP cycle. This includes hosting additional webinars that are focused on engaging communities most impacted by REAP zone development and building strategic partnerships with organizations and entities that can help expand that reach.

Strategic Element 2: Transitioning to a Decarbonized Electricity Mix

Strategic Element 2 outlines how Illinois can plan, model, and coordinate the generation and transmission investments required to meet CEJA's legislative requirements reliably and cost-effectively. A capacity expansion model and resource adequacy model were built to fulfill this objective. The figure below shows how these models interact with each other and where they sit within the overall IPF.

Figure ES 2: Electric System Modeling Approach with Resource Adequacy Considerations

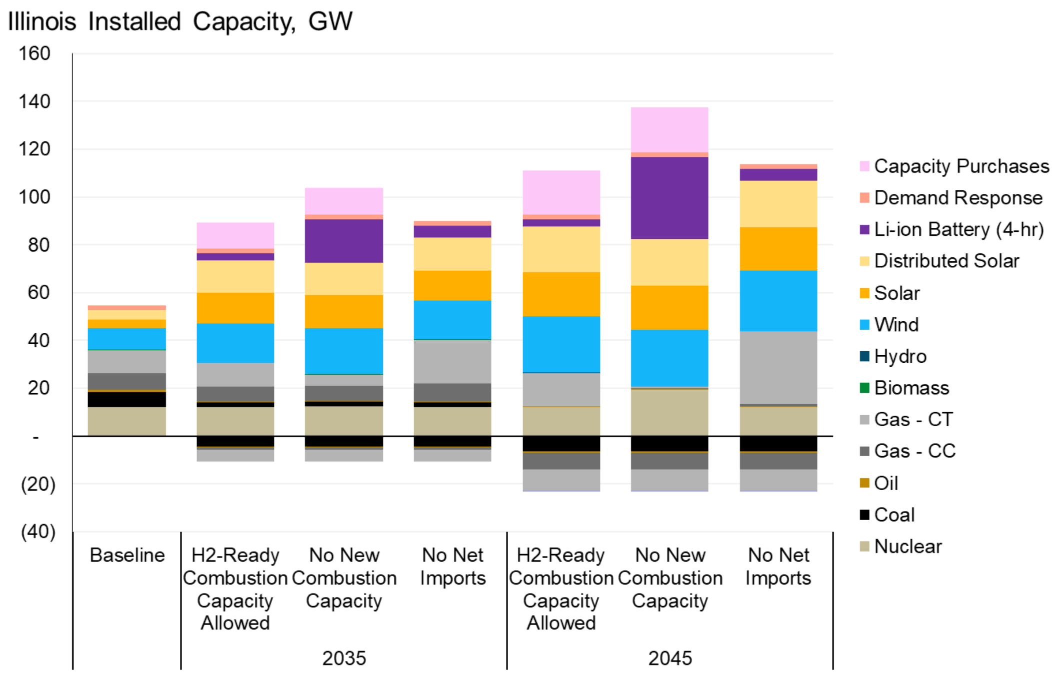


This modeling approach was then demonstrated using three scenarios that evaluated the impact of restricting different resource options in the long term and their impact on overall resource and transmission needs. A load forecast (including data centers) was developed informed by load forecasts from the Regional

Transmission Organizations (RTOs) and Investor-Owned Utilities (IOUs) and used across all scenarios. A 50% Renewable Portfolio Standard (RPS) by 2040 and fossil emissions reduction mandated by CEJA were also modeled in all three scenarios.

Findings suggest that substantial growth in in-state renewable energy is needed to meet the 50% RPS by 2040. This **renewable energy, combined with existing nuclear, may help meet 95+% of the state's annual energy needs.** The remaining energy may come from imports or incremental in-state clean generation based on scenario**. Battery storage and new firm capacity both have a role to play in supporting system balancing needs and maintaining reliability over different timescales.** The former can provide sub-hourly and intra-day balancing while the latter can help maintain reliability during multi-day periods with low renewable generation. Imposing restrictions on certain resource options can drive the need to "overbuild" other resource options and transmission. The figure below shows the total statewide modeled nameplate capacity by resource type in these scenarios.

Figure ES 3: Statewide Resource Nameplate Capacity by Scenario in Select Years, GW



Baseline includes existing resource portfolio plus near term planned builds.

Future REAP cycles can continue to build on this foundation in the following ways:

Strategic Element 2 Recommendations
+ Additional scenario analysis to evaluate impacts of electrification for economywide decarbonization, inter-regional transmission expansion, etc.
+ Continue to update assumptions to maintain alignment with latest planning efforts at the utility and RTO levels
+ Additional exploration of ATTs and NWAs using the IPF
+ Demonstrate the remaining steps in the IPF with identification of near-term actions and mapping long term resource additions to substations to refine subsequent transmission analysis

Strategic Element 3: Managing Land Use in Renewable Deployment

Strategic Element 3 examines how Illinois can refine and operationalize REAP zones to support cost-effective, community-aligned renewable and transmission development. During this cycle, the REAP zones identified in 2024 were geocoded with slight adjustments to more accurately reflect network topology as shown in the figures below. In addition, areas not previously located in REAP zones were assigned to new named zones. This was to account for the transmission headroom created by fossil retirements in those areas that could support integration of new resources identified through the IPF. Resource potential, interconnection costs and local transmission network related assumptions were developed for each zone. The Illinois Department of Natural Resources helped identify data sets that will continue to be used to estimate the suitability of land within each zone for siting electric infrastructure.

Figure ES 4: Previous Cycle REAP Zones

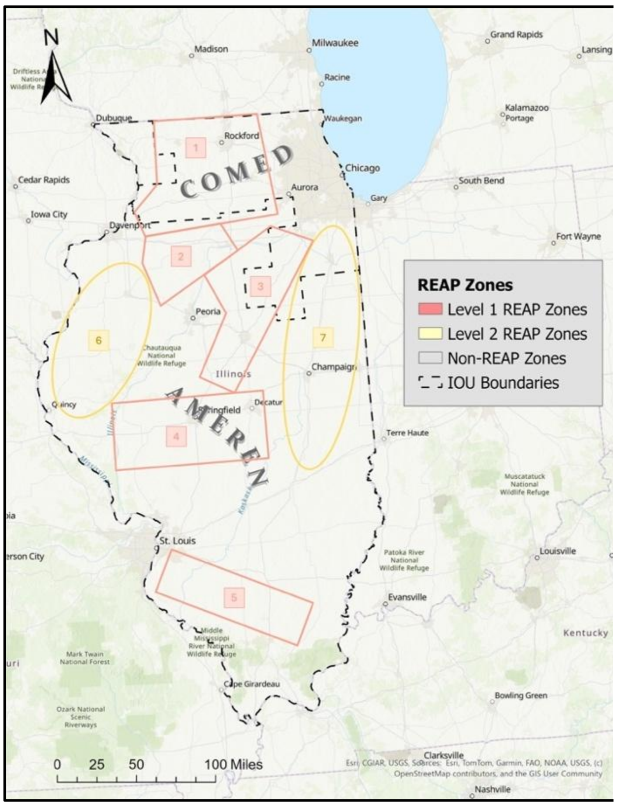
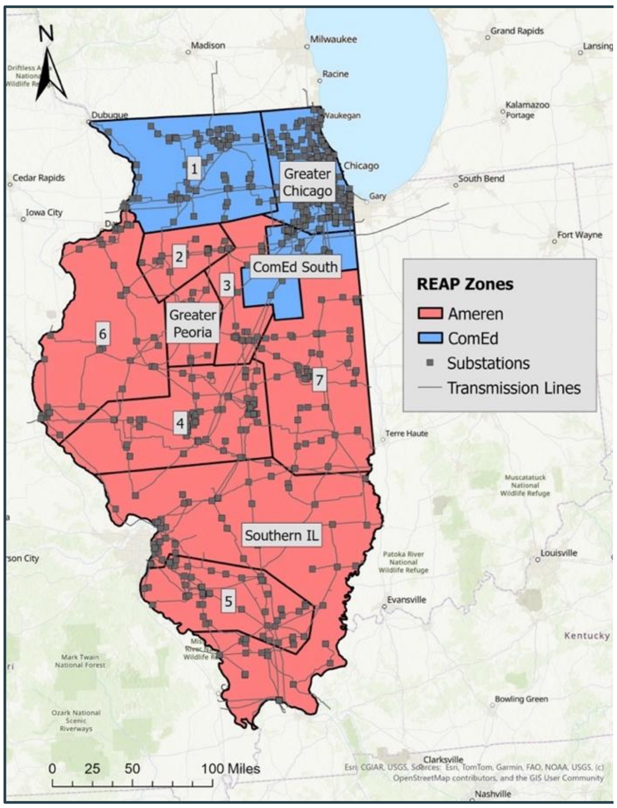


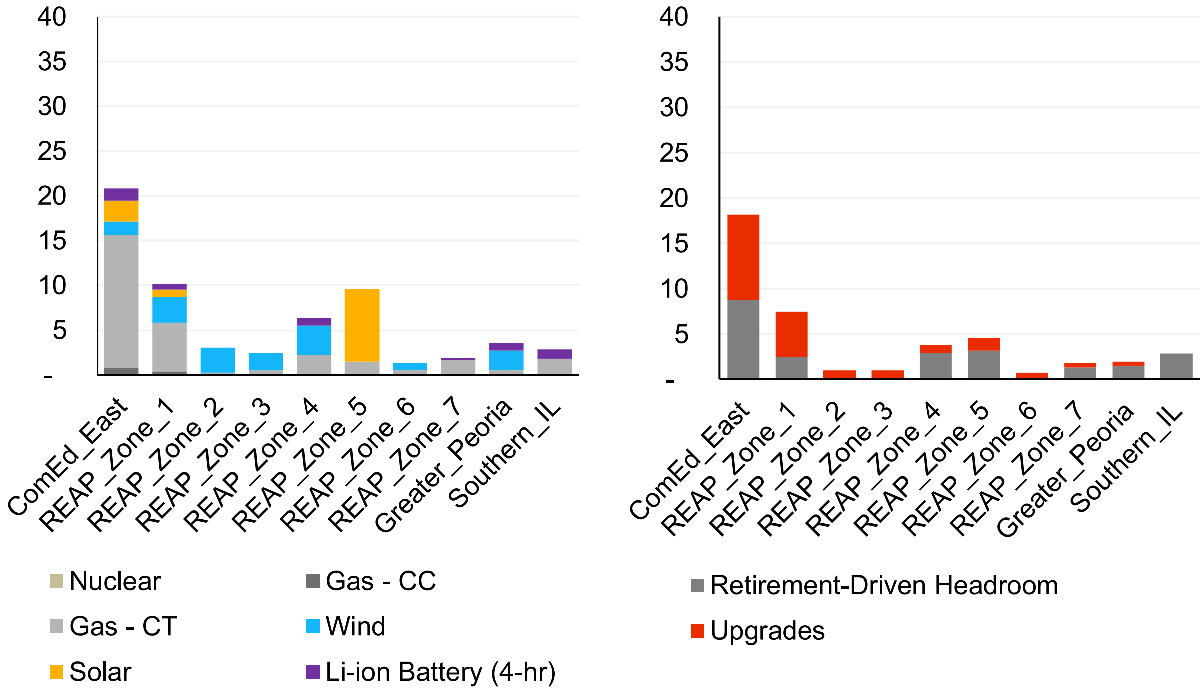
Figure ES 5: Latest Geocoded REAP Zones



Separating Illinois into ComEd and Ameren (LRZ 4) is a visual simplification. In addition to parts of the state falling within MISO LRZs 1 and 3, several municipal utilities and co-ops are spread throughout. While not shown in the figure above, the loads and resource potential associated with these regions are accounted for in the electric sector modeling.

Preliminary analysis across the three scenarios indicates that **even after applying land use filters, the state has approximately 70 GW of utility-scale solar and 26 GW of wind potential,** which would be more than sufficient to meet the state's 50% RPS by 2040. **Fossil retirements to meet CEJA emission reduction requirements will drive 23 GW of transmission headroom** which can help integrate new resources. However, **35 GW of new effective resource capacity will be required to maintain reliability given assumed load growth and fossil retirements.** Thus, **incremental transmission upgrades will likely be necessary** to integrate sufficient renewables, storage and firm resources to meet the RPS and maintain reliability. Later in this report, Strategic Elements 2 and 3 will describe how resources and transmission upgrades selected varies across scenarios based on in-state and out-of-state resource options assumed to be available. Strategic Element 4 then explores the role that ATTs and NWAs can play in mitigating these infrastructure needs.

Figure ES 6: Installed Nameplate Capacity of Resources Selected (Left) Using Transmission Headroom and Upgrades (Right) by REAP Zone by 2045 When Net Imports Are Not Allowed (GW)



ComEd East in the figure above includes both Greater Chicago and ComEd South REAP zones for simplicity.

These results illustrate where land use impacts may be expected across the state. Impacts will vary based on infrastructure type and whether the project is brownfield (line upgrades, building new generation to replace retirements on the same site) or greenfield (new lines and generation in areas where no previous infrastructure exists). As REAP cycles progress, assumptions will continue to be refined, and additional scenarios will continue to be explored. Infrastructure needs consistently observed across scenarios can help the state anticipate land use impacts and engage with local communities early.

Future REAPs can continue to build on this foundation in the following ways:

Strategic Element 3 Recommendations
+ Continued analysis to estimate suitability of land for infrastructure development to refine REAP zones and inform siting of resources
+ Continued refinement of assumptions and scenario exploration with the IPF to refine estimates of infrastructure needs across different zones, and understand the associated land use impacts
+ Continued outreach to communities that may host energy infrastructure as results from the REAP become increasingly actionable

Strategic Element 4: Effective Transmission Planning and Utilization

Strategic Element 4 examines how Illinois can meet the transmission needs identified in Strategic Element 3 through both conventional infrastructure and other alternatives. Building on the 2024 REAP, the chapter highlights how interconnection backlogs, queue reform under FERC Order 2023, and evolving regional planning processes continue to shape the state's ability to integrate the large volumes of renewable and storage capacity required to meet policy targets. Additionally, this chapter takes a step forward by focusing on ATTs and NWAs for maximizing use of the transmission system.

In addition to transmission expansion, **ATTs and NWAs can be complementary tools that can reduce costs, defer upgrades, and alleviate congestion.** ATTs such as dynamic line ratings, advanced conductors, topology optimization, advanced power flow controllers, and storage-as-transmission only assets may unlock additional near-term headroom or mitigate targeted constraints. NWAs and other broader system solutions, including distributed energy resources (DERs), demand response, energy efficiency, and virtual power plants, can offer localized relief and help to defer larger upgrades. In order to evaluate ATTs and NWAs, the REAP proposes a structured framework for evaluating these alternatives using avoided-cost methods, comparative benefit-cost assessment, and operability screening aligned with RTO planning requirements.

The proposed **avoided-cost framework** begins by identifying transmission constraints, defining the conventional upgrades needed to address them, and estimating their total cost. It then determines when and how often each constraint binds to establish the hours of need, which are used to calculate an hourly avoided-cost value as the benchmark for comparing alternatives. Candidate ATTs and NWAs will be screened for technical fit, operational compatibility, and their ability to reduce binding hours. For each viable ATT or NWA, the proposed framework will then quantify costs, estimate its effectiveness, and calculate avoided-cost benefits, scaled when the ATT or NWA provides only partial relief, while adding other monetizable benefits such as congestion or curtailment reduction. **Comparing these benefits to costs will support an evaluation of whether an ATT or NWA can fully or partially defer the conventional upgrade, identifying the most cost-effective and reliable solution or portfolio.**

Lastly, regulatory and institutional alignment will be paramount to effectively deploy these solutions. While Federal Energy Regulatory Agency orders (including Orders 1000, 881, 2023, and 1920) increasingly require RTOs to consider ATTs, both **MISO and PJM are still in the early stages of integrating these technologies into planning and work remains to ensure consistent methodologies are developed for assessing their reliability contributions or cost-recovery pathways.** ICC will continue to engage with the RTOs on how to best advance ATT assessments from planning integration to cost recovery pathways.

Strategic Element 4 Recommendations
+ Future REAP cycles should investigate ways to evaluate ATTs as part of the IPF
+ Future REAP cycles should explore where DERs, flexible load and other NWAs may provide locational value
+ ICC could direct Ameren and ComEd to identify ATT opportunities on their systems that could aid in meeting REAP zone needs

Strategic Element 5: Leveraging Regional Processes and Markets

The REAP modeling framework identifies the transmission needed to achieve renewable deliverability; **turning those needs into actual projects requires navigating the regulatory pathways that enable their approval and development**. Transmission development can proceed through several channels including reliability planning, economic planning, long-term scenario-based planning under FERC Order 1920, state-initiated pathways such as the State Agreement Approach, and local "supplemental" or "other" projects. **Each pathway offers a different balance of speed, cost allocation, and alignment with Illinois' policy-driven transmission needs**, as shown in Table ES 1: Regulatory Pathways for Fulfilling REAP Identified Needs.

Across both RTOs, a range of regulatory mechanisms can advance transmission projects that support Illinois' goals. Annual reliability and economic planning processes evaluate system conditions and congestion patterns, selecting upgrades that address immediate or cost-justified needs. MISO's Multi-Value Projects and Long-Range Transmission Planning initiatives offer a regional structure for projects that support renewable integration and long-term system transformation. PJM's State Agreement Approach provides a means for states to nominate and advance policy-driven projects directly. Local and supplemental planning undertaken by transmission owners can also be leveraged to create incremental capacity when aligned with broader system needs. **Each of these pathways plays a role in ensuring Illinois has access to a transmission system capable of supporting expanding renewable portfolios.**

Table ES 1: Regulatory Pathways for Fulfilling REAP Identified Needs

Regulatory Pathway	Frequency of Process	Cost Allocation	Relevance to REAP Needs
Reliability Planning	Every 12-18 Months	Regional	Opportunity for Right-Sizing to Align with REAP Needs
Economic Planning	Every 12-24 Months	Regional	Opportunity for Right-Sizing to Align with REAP Needs
LRTP / Order 1920 Compliance Processes	Every 3-5 Years	Regional	Direct Opportunity to Address REAP Needs
State Agreement Approach	Can Propose through RTEP	Local	Direct Opportunity to Address REAP Needs
"Other" or "Supplemental" Projects	Rolling process	Local	Opportunity for Right-Sizing to Align with REAP Needs

FERC Orders 1920, 1920-A, and 1920-B introduce a new long-term, scenario-based planning framework intended to identify forward-looking, multi-value transmission needs. Order 1920 is one of the most significant shifts in RTO planning since the 2024 REAP was approved. For the first time, transmission providers must incorporate state laws, including CEJA, directly into their planning scenarios, consult with states on how those laws shape long-term needs, and evaluate projects using a standardized multi-benefit methodology. This framework creates the strong potential alignment between Illinois' clean-energy goals and regional transmission planning, particularly because it allows states to request additional scenarios that reflect policy-driven needs.

These evolving regulatory structures also support a closer alignment between transmission planning and interconnection reform. Proactive planning under Order 1920 can reduce the need for piecemeal upgrades triggered by individual generator requests. At the same time, leveraging recent surplus interconnection service reforms in both MISO and PJM could allow new resources to make earlier use of that headroom. Together, **these pathways position Illinois to leverage regional planning and market processes more effectively**, ensuring that transmission development keeps pace with the state's clean-energy transition and that REAP-identified needs translate into timely and cost-effective infrastructure investments.

Strategic Element 5 Recommendations
+ Prioritize regulatory pathways for transmission development that enable regional allocation of costs.
+ Explore expanding regional cost allocation pathways to enable state-driven projects with cost allocation reflecting shared regional benefits
+ Coordinate REAP planning efforts with emerging FERC Order 1920 processes for effective long-term transmission planning
+ Examine opportunities to where right-sizing or incremental upgrades can help reduce costs for Illinois customers while supporting REAP policy goals
+ Support and strengthen MISO–PJM Interregional Transfer Capability Study efforts to align assumptions, advance identified solutions, and improve interregional coordination
+ Examine if surplus interconnection reforms can be extended to proactive transmission upgrades that create headroom for renewables

Introduction

Purpose and Scope of the REAP

Section 8-512 of the Public Utilities Act (220 ILCS 5/8-512) directs the ICC to develop and update a REAP for the State of Illinois every two years. The purpose of the REAP is to provide a comprehensive and actionable framework to ensure that Illinois can achieve the targets established under CEJA in a manner that is equitable, reliable, and cost-effective. The REAP examines and quantifies the legislative requirements and goals of CEJA, identifies the renewable and clean energy resources needed to meet those targets over time, and recommends strategies for coordinating transmission planning, interconnection, and regional market participation to facilitate the timely and affordable delivery of clean electricity to Illinois consumers.

This report presents the findings from the second cycle of the REAP. Building on the findings and recommendations of the first REAP ("2024 REAP"), approved by the Commission in 2024, this second iteration incorporates updated data, analyses, and stakeholder input to reflect new and ongoing developments in state and federal policy, regional transmission planning, and market operations. The second REAP continues the role of identifying the renewable energy and transmission needs of the State, refining the REAP zones, and evaluating near- and long-term actions required to maintain progress toward CEJA's 50 percent RPS by 2040 and eliminating greenhouse gas emissions from large in-state fossil units by 2045.

The scope of this REAP includes: (1) an updated assessment of renewable energy supply needs and available resource potential; (2) analysis of transmission infrastructure and needed system headroom to support delivery of renewable energy; (3) identification of policy and procedural reforms to improve how regional transmission planning can support Illinois policy achievement; and (4) coordination with ongoing efforts of the IPA, the RTOs serving Illinois (PJM Interconnection, "PJM" and Midcontinent Independent System Operator "MISO"), and other state and regional entities. As with the 2024 REAP, this report is intended to inform the Commission's investigation of renewable access needs and guide continued collaboration with stakeholders in advancing the State's clean energy transition.

Legal and Statutory Framework

Climate and Equitable Jobs Act

CEJA, or Illinois Public Act 102-0662, was signed into law on September 15, 2021. CEJA established Illinois' state mandate to eliminate greenhouse gas emissions from all large fossil generation units by 2045 and a state policy goal to reach 100% clean energy by 2050, among other decarbonization and equity goals. CEJA built upon previous legislative and policy targets, and created the long-term vision for an equitable, reliable and cost-effective clean energy transition for Illinois. The law establishes several major clean energy goals and legislative requirements, including:

- **100% economy-wide clean-energy goal by 2050:** CEJA affirms Illinois' commitment to transition all sectors of the economy to clean energy by mid-century, as reiterated across multiple provisions of the law. The legislation defines clean energy as generating sources 90% or greater free of carbon dioxide emissions, including both renewable and nuclear.
- **50% renewable portfolio standard by 2040:** CEJA directs the IPA to procure renewable energy to meet a goal of 40% RPS by 2030 and a goal of 50% RPS by 2040 for eligible customer classes. These

requirements apply to Ameren and MidAmerican retail customers within MISO's footprint and ComEd retail customers within PJM's footprint. Municipal utilities, rural cooperatives, and Mount Carmel Public Utility are not subject to these requirements. CEJA also places budget caps to limit the incremental costs to consumers from procuring renewable energy, and utilities unable to meet the RPS due to the approved budget caps will not face penalties for failing to meet the RPS target. This budget cap limits the total budget available for renewable contracts and has historically restricted the pace at which IPA can procure new renewable resources.[1]

+ **Fossil fuel phaseout in electricity generation by 2045:** CEJA requires that all coal and natural gas plants above 25 MW must achieve zero greenhouse gas emissions by 2045. Privately owned coal and oil-fired generation must reduce emissions to zero by January 1, 2030, while publicly owned (Municipal/Co-op) coal and oil-fired generation must reduce emissions by 45% by 2035, with a possibility for an extension until 2038, and fully reduce emissions to zero by December 31, 2045. CEJA sets privately owned natural gas fired generation on a scheduled phaseout between 2030 and 2045 based on its emissions and proximity to Environmental Justice (EJ) communities or equity investment eligible communities. Publicly owned natural gas fired generation facilities are subject to a later schedule, they must have zero emissions by January 1, 2045. Natural gas fired generation can reduce its emissions to zero by retiring or converting to 100% green hydrogen or similar technology. It also subjects privately owned natural gas units over 25 MW to emissions caps based on 2018–2020 levels (or, for newer plants, their first three years of operation), with compliance demonstrated through rolling 12-month average emissions. The Illinois Environmental Protection Agency (EPA) manages enforcement. MISO, PJM and the ICC can also designate fossil fuel plants as necessary for reliability to serve as emergency backup generation, allowing plants to exceed greenhouse gas emissions restrictions.
+ **Extended support for nuclear generation through Carbon Mitigation Credits (CMCs):** The Future Energy Jobs Act or Illinois Public Act 99-0906, which took effect June 1, 2017, authorizes Zero Emission Credit payments to two nuclear plants in Illinois through mid-2027. CEJA similarly authorizes Carbon Mitigation Credit payments to three additional nuclear plants through mid-2027. Together, these programs sustain Illinois' existing nuclear fleet.

REAP Requirements

Section 8-512 of the PUA established the requirement for the ICC to develop a REAP for the State of Illinois, beginning with a first approved report in May 2024 and a requirement to update the REAP every other year from then on.[2] The legislation articulates the need for a "cost-effective transmission system" that "ensures reliability of the electric transmission system, lowers carbon emissions, minimizes long-term costs for consumers, and supports the electric policy goals of this state."[3] This REAP, building on the 2024 REAP, establishes an actionable framework to further those goals.

The law requires that the REAP address seven requirements:[4]

1. Designate REAP zones that are well suited for renewable energy development
2. Develop a transmission plan that enables the delivery of energy from REAP zones

---

[1] *Illinois Power Authority "2026 Long-Term Renewable Resources Procurement Plan" Filed for Illinois Commerce Commission Approval, October 20th, 2025.*
[2] *220 ILCS 5/8-512.*
[3] *220 ILCS 5/8-512(a).*
[4] *220 ILCS 5/8-512(b).*

3. Leverage Illinois' position as an electricity and power generation hub to encourage new investments in renewable resources
4. Identify in-state programs, policies, and transmission projects that cost-effectively deliver bulk-system renewable energy to meet RPS targets under Section 1-75(c) of the IPA Act
5. Consider ways to improve regional and interregional system planning processes to improve reliability, reduce emissions, create jobs and improve cost-effective delivery
6. Propose recommendations on the best locations of REAP zones and the transmission upgrades needed to cost-effectively meet state policy goals

    6.5 Make findings and policy recommendations based on analysis regarding the impact of converting non-powered dams to hydropower dams relative to alternative renewable energy resources

7. Present the above findings and recommendations and identify actions the Commission can take

This is the first update to the REAP report. The ICC will continue to iterate and improve upon each REAP every two years, taking new developments, policies and energy sector developments into account.

Equity in the REAP

As part of its broader clean energy goals, CEJA places a strong emphasis on ensuring an equitable energy transition, particularly for EJ communities and other areas eligible for equity investment. The legislation requires a faster phaseout of emissions from the state's most polluting fossil fuel plants near EJ communities, establishes workforce development programs for eligible communities and business owners, and directs new funding toward historically disadvantaged populations.

The REAP zones established in the first cycle were developed with equity-focused principles in mind, and this REAP cycle builds on that foundation. The following highlights how equity continues to be considered in the REAP as well as opportunities for future analysis to deepen these efforts:

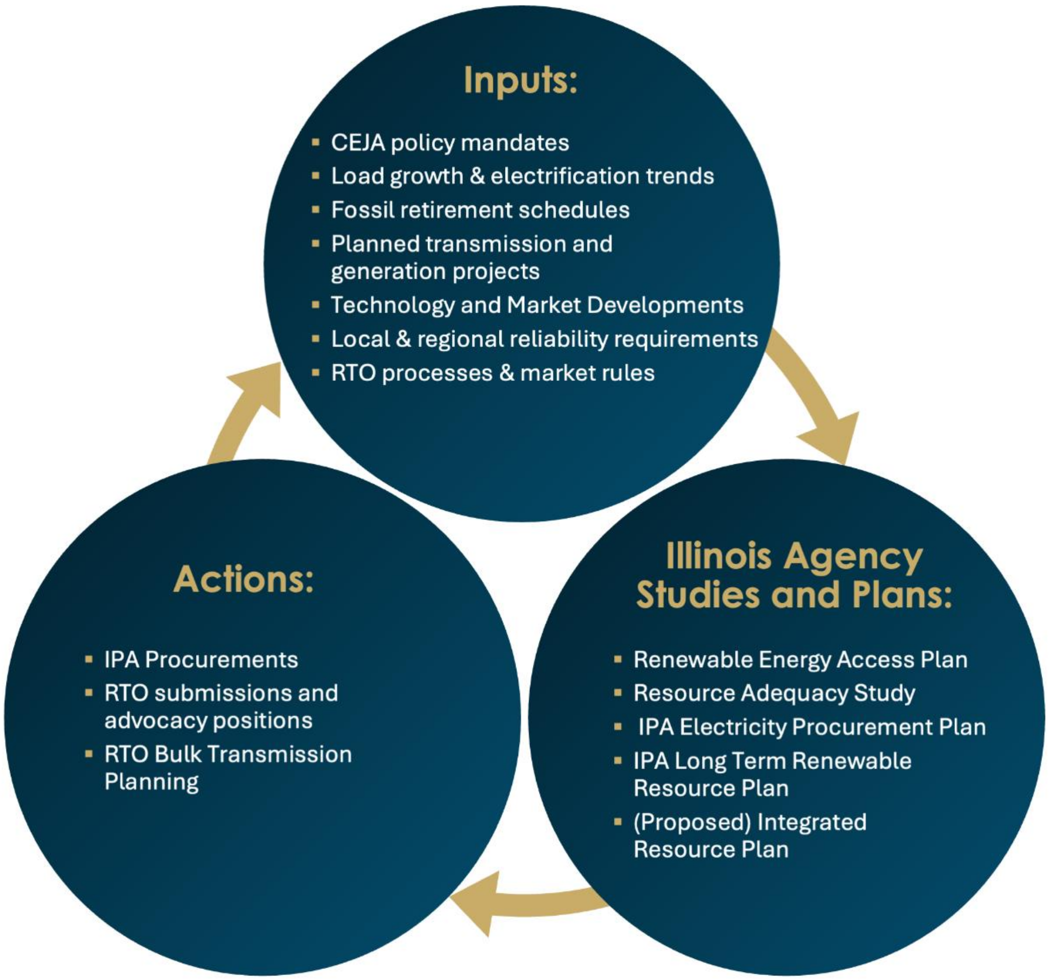
+ **Air quality and fossil plant phaseouts near EJ communities:** CEJA sets emission reduction schedules for fossil-fueled electric generation, prioritizing units with high emissions located near EJ communities, subject to reliability exceptions and Illinois EPA enforcement.
+ **Land use considerations in REAP Zone development:** Equity was a core consideration in identifying initial REAP zones and assessing land use and permitting processes. Equity and agricultural productivity informed the identification. In developing updates to this REAP, ICC engaged with IDNR to identify any additional data sources that could be used to refine the REAP zones in future cycles and understand suitability of land within each zone for siting long term infrastructure needs identified.
+ **Equitable access to jobs and revenues during the transition:** CEJA anticipates tens of thousands of new jobs in the renewable energy sector, alongside job training programs for EJ communities and other underserved populations. Clean energy development and deployment within REAP zones will further Illinois' progress towards these goals.
+ **Ensuring reliability and affordability during the clean energy transition:** CEJA's goal to achieve 100% clean energy by 2050 must be implemented in a way that is fair and equitable.

REAP Intersection with Other Illinois Agency Plans and Studies

Illinois' energy system is guided by a set of interrelated planning processes including the REAP, the Resource Adequacy Study, the IPA's annual Electricity Procurement Plan and biennial Long-Term Renewable Resources

Procurement Plan, and, pending gubernatorial approval, a new Integrated Resource Plan (IRP) requirement, discussed further in the *Changes in Illinois State Policy* section below. Although these processes operate on different statutory timelines and address distinct components of the electricity system, they are designed to be mutually reinforcing. As demonstrated in Figure 1, these studies work from a common set of inputs, which are studied to guide actions needed to meet State needs. REAP identifies transmission, headroom, and siting needs; the Resource Adequacy Study evaluates evolving reliability conditions; and the IPA's procurement plans secure the renewable resources needed to meet statutory objectives. If enacted, the IRP framework would add a systemwide portfolio and long-term planning lens that aligns load forecasts, resource needs, and transmission expansion. Together, these processes create an iterative and increasingly coordinated foundation for ensuring that Illinois can meet its policy targets while maintaining customer affordability and system reliability.

Figure 1: Interaction between Illinois State Agency Studies and Plans



Progress since the 2024 REAP

Since approval of the 2024 REAP, the ICC moved from concept to execution on several items. The following section highlights ICC's external advocacy in advancing the Commission's directives from the 2024 REAP Order.

Illinois Commerce Commission RTO Advocacy Actions

The ICC continues to be an active participant in regional and federal regulatory processes to advance the Commission's directives. ICC has submitted or joined more than 30 filings at FERC and is actively engaged in RTO stakeholder processes. These actions demonstrate sustained advocacy for transmission planning reforms, resource adequacy, state oversight, and alignment with achieving Illinois' clean energy policies. ICC has consistently pressed for stronger regional planning and better use of innovative technologies. ICC supported FERC Order 1920, which directs RTOs to expand scenario-based long-term planning and incorporate ATTs.[5] ICC also submitted comments in favor of strategic use of DLRs[6,7,8] and supported the OMS-endorsed Joint Targeted Interconnection Queue (JTIQ) reforms to accelerate transmission development in MISO and SPP.[9] In presentations to PJM, ICC Staff urged development of long-term, policy-driven scenarios that incorporate realistic load growth, retirements, and siting limits, and have called for use of all seven Order 1920 benefit metrics to identify[10] ICC Staff have also encouraged PJM to pursue a holistic approach for scenario development that jointly captures reliability, economic, and public-policy[11] These efforts directly advance the REAP Order's direction for Illinois to ensure RTO planning processes incorporate CEJA requirements, utilize REAP zones, and support timely, cost-effective transmission expansion.

Reflecting the 2024 REAP Order directive to elevate the state perspective, ICC also joined the Organization of PJM States Inc. (OPSI) in emphasizing the need for states' authority to be respected in transmission planning,[12] and supported the Maryland PSC's proposal for PJM to consider non-transmission alternatives in its planning process.[13] ICC has actively supported reforms to speed interconnection and refine capacity markets. This includes support for MISO queue reforms such as higher milestone payments and queue caps,[14,15,16] as well as PJM reforms allowing capacity interconnection rights (CIR) transfers and better use of available transmission headroom.[17,18] ICC joined comments urging PJM to end must-offer exemptions,[19,20] account for reliability must-run (RMR) units,[21,22] refine effective load carrying capability (ELCC) methods,[23] and strengthen performance obligations.[24]

The ICC also worked closely with MISO on its Expedited Resource Addition Study (ERAS) process. With ERAS, MISO sought to create a time limited process to fast-track generation to meet growing resource adequacy concerns.[25] The ERAS process aims to select resources that could come online quicky to meet reliability needs

---

[5] *"Resolution in Support of the Federal Energy Commission's Order 1920." May 13th, 2024.*
[6] *"Comments of the Illinois Commerce Commission" FERC Docket No. RM24-6-000*
[7] *"Comments of Organization of PJM States" FERC Docket RM24-6-000*
[8] *"Comments of Organization of MISO States" FERC Docket RM24-6-000*
[9] *"Comments of Organization of MISO States" FERC Docket ER24-2797*
[10] *For presentation see: item-07---zachary-callen---illinois-commerce-commission-presentation.pdf*
[11] *For presentation see: item-07---amanda-lescano-njbpu-and-hannah-mccorry-icc---presentation.pdf*
[12] *"Comments of Organization of PJM States" FERC Docket RM21-17*
[13] *"Comments of Organization of PJM States" FERC Docket ER23-2612*
[14] *"Comments of the Organization of MISO States" FERC Docket ER25-507*
[15] *"Errata to Notice of Intervention and Comments of Organization of MISO States" FERC Docket ER24-340*
[16] *"Notice of Intervention and Comments of Organization of MISO States" FERC Docket ER24-341*
[17] *"Comments of the Organization of PJM States" FERC Docket ER25-778*
[18] *"Comments of the Organization of PJM States" FERC Docket ER25-1128*
[19] *"Comments of the Organization of PJM States" FERC Docket ER25-785*
[20] *"Comments of the Organization of PJM States" FERC Docket ER25-682*
[21] *"Comments and Motion to Lodge of the Organization of PJM States" FERC Docket EL24-148*
[22] *"Comments of the Organization of PJM States" FERC Docket ER25-682*
[23] *"Comments of the Organization of PJM States" FERC Docket ER25-682*
[24] *"Comments of the Organization of PJM States" FERC Docket ER25-785*
[25] *MISO filing: https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20250606-5228*

and move them through an expedited interconnection process. The ICC and MISO worked together to develop a process that ensured Illinois resources could take advantage of ERAS given Illinois's regulatory structure.

To ensure reliability as Illinois transitions to cleaner resources, ICC has supported reforms that improve accreditation, pricing, and risk assessment. ICC backed adoption of a reliability-based demand curve in MISO to reduce price volatility,[26,27] supported improved demand response accreditation[28] and shortage pricing reforms,[29] and pressed PJM to develop new risk metrics and weather models.[30] ICC also unsuccessfully opposed proposals that would set a higher CONE in ComEd, emphasizing CEJA's plant retirement schedule and the importance of maintaining affordability while achieving clean energy goals.[31] ICC further highlighted Illinois' leadership on resource adequacy and called for RTOs to improve queue management, transmission planning, and approaches to load growth.[32]

In addition to national advocacy, ICC has taken steps to enable major transmission projects consistent with REAP objectives. The Commission has approved a Certificate of Public Convenience and Necessity for a major transmission project,[33] and has supported MISO Tranche 2.1 projects challenged at FERC.[34] Taken together, these actions demonstrate that ICC has actively worked towards implementing the 2024 REAP Order's directives. By advancing transmission planning, improving market design, safeguarding reliability, and ensuring that state policy priorities are represented in regional processes, ICC is laying the groundwork for successful delivery of REAP's clean energy and reliability goals.

Changes in State, Federal and RTO Policies Impacting REAP Development

Since the approval of the 2024 REAP, there have been several changes in state and federal policy that impact the development of REAP zones in Illinois. These changes impact nearly every aspect of REAP zone development including siting, transmission planning, interconnection reform and capacity market changes. The changes outlined below are among the most significant in terms of REAP zone development in Illinois.

Illinois State Policy and Legislation

Since the 2024 REAP, there have been three changes in the state landscape that are important to contextualize this REAP. Specific to the Illinois energy sector, Public Act (PA) 103-1066 enacted on February 20, 2025, expands the IPA's authority to determine REC methodologies, touching on procurement certainty and stability, which affects investment signals that the REAP must plan around. Because the REAP involves engaging transmission and siting for renewable projects, having secure REC contracts and clarity in procurement

[26] *"Comments of the Illinois Commerce Commission in Support of the Proposed Tariff Revisions filed by MISO" FERC Docket ER23-2977 https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20231020-5076&optimized=false&sid=8d45b1ee-5307-45be-a5f5-865d72ea7fc1*
[27] *"Comments of the Organization of MISO States" FERC Docket ER23-2977*
[28] *"Comments of the Organization of MISO States" FERC Docket ER25-1886*
[29] *"Comments of the Organization of MISO States" FERC Docket ER25-579*
[30] *"ER24-99 – supported OPSI comments pushing PJM on new risk metrics, weather models, and capacity reforms".*
[31] *"Comments of the Illinois Commerce Commission in Opposition to the Proposed Tariff Revisions Filed by the PJM Interconnection" FERC Docket ER24-462*
[32] *Prefiled Statement of Chairman Doug Scott, Illinois Commerce Commission, for the Technical Conference on Meeting the Challenge of Resource Adequacy in RTO/ISO Regions.*
[33] *Grainbelt CPCN: https://www.icc.illinois.gov/docket/P2022-0499/documents/334872/files/583350.pdf*
[34] *"Comments of ICC in Opposition to the Complaint of the Concerned Commissions" FERC Docket No. EL25-109. Sept. 9, 2025.*

targets (and flexibility to make contracting adjustments to meet such targets) influences what zones or projects are viable.

The IPA's Long-Term Renewable Resource Procurement Plan (LTRRPP) determines how renewable resources are procured to meet the statutory RPS requirements. The 2026 LTRRPP includes several updates relevant to the REAP's transmission and siting analysis.[35] To improve project delivery and reduce attrition, the IPA proposes to add optional post-award adjustments in Indexed REC contracts, allowing limited inflation-based strike price and REC quantity changes to keep projects financeable amid cost volatility. Public Act 103-1066 provisions also ensure payment continuity by the IPA if the rate-impact cap constrains collections while temporarily pausing new procurements if needed, providing clearer pacing signals for zone-aligned development. The LTRRPP maintains a biennial update schedule that aligns with the REAP's iterative framework.

Lastly, in October 2025, the Illinois General Assembly passed a comprehensive energy package, colloquially called the Clean and Reliable Grid Affordability Act (CRGA), Illinois Senate Bill 25, that expands the State's long-term planning and procurement responsibilities. At the time of this report, the legislation is not enacted, because it has not yet been signed by the Governor. Since the legislation has not been enacted at the time of this drafting of the 2025 REAP, scenarios studied and the REAP here do not reflect this legislation. If enacted, it would take effect on June 1, 2026.

The legislation directs the ICC to strengthen its system planning oversight by establishing a new Integrated Resource Plan (IRP) process, creates a storage procurement target and plan, and updates the REAP framework among other changes.

If signed, the legislation would require an updated REAP investigation within 180 days of the law's effective date, expanding the plan's statutory mandate to include transmission alternatives, ATTs, and headroom analysis. The REAP update must evaluate implementation progress, recommend improvements to the REAP process, assess areas of recent congestion, examine interregional transmission solutions, and consider how ATTs could alleviate transmission constraints. The legislation proposes that the REAP include an evaluation of proposed transmission projects, including ATTs, and develop a list of recommended transmission and ATT projects. Utilities may submit ATT and headroom studies for ICC consideration, and the REAP must be shared with MISO and PJM to promote regional coordination.

Changes in Federal Policy, Regulation and Major RTO Filings

Federal Policy Changes

There have been several significant federal policy and regulatory changes since the 2024 REAP. The most impactful federal policy shift for clean energy development costs is the FY2025 Congressional Budget Reconciliation Bill (Reconciliation Bill). The Reconciliation Bill modified technology-neutral tax credits 45Y production tax credit (PTC) and 48E investment tax credit (ITC) for all resources, however solar and wind are the most immediately impacted with an accelerated tax credit phaseout schedule. Solar and wind projects must be placed in service by December 31, 2027 to remain eligible for the PTC or ITC. Under the safe harbor provisions, projects must begin construction by July 4, 2026 and reach commercial operation date within four years to claim the full tax credit value. Tax credits for other resources such as geothermal, standalone Li-ion

[35] *2026 Long Term Renewable Resource Procurement Plan: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20251020-2026-long-term-renewable-resources-procurement-plan.pdf*

batteries, and nuclear were preserved and will remain in effect until 2032, while electrolyzers will be eligible for the PTC until 2027.[36] Resource costs and project financing risks will increase relative to 2024 expectations, which in turn will impact future clean energy investment decisions in REAP zones.

The Reconciliation Bill also tightens "Foreign Entity of Concern" (FEOC) restrictions that apply to federal clean-energy tax credits. FEOC rules prohibit the use of components manufactured or assembled by entities controlled by certain foreign governments, and eligibility for tax credits hinges on demonstrating compliance with these sourcing requirements. Because the global supply chains for solar modules, wind turbine components, and Li-ion batteries rely heavily on materials and intermediate products from FEOC-designated countries, these technologies face higher risks of disqualification from federal credits unless domestic or non-FEOC suppliers can be secured.[37] This introduces additional uncertainty into procurement, pricing, and delivery timelines, raising both near-term development costs and long-term financing risks for projects.

In addition to federal policy changes through legislation, wide-ranging tariffs have been initiated across U.S. trading partners. The technologies that will be most impacted by these tariffs are those with a high percentage of imported components, and those dependent upon imports from China. Solar and wind will be negatively impacted, but Li-ion batteries are the most impacted because they depend on China for a large share of battery cabinets and balance of system (BOS) modules.[38] Compared to the Reconciliation Bill's expedited rollback of clean energy tax credits, tariffs have a smaller impact on resource costs but are still likely to increase near-term clean energy investment costs that may impact Illinois' REAP zones.

Federal Regulatory Changes

In May 2024, FERC issued Order 1920, which has the potential to have a meaningful impact on how transmission solutions for REAP zones are planned and cost allocated. Order 1920 established new requirements for regional electric transmission planning and cost allocation to address infrastructure needs and future demand growth in the electric sector.[39] Every five years, with the option to do so every three years, regional transmission operators must design and analyze at least three long-term planning scenarios to identify transmission needs. Necessary and beneficial projects, assessed across seven benefit criteria, are selected by year three in each cycle. Additionally, it facilitates a process for streamlined interregional long-term transmission planning and requires increased transparency in local transmission planning.

In updates to the Order, Order Nos. 1920-A and 1920-B, FERC affirmed that states will be key decision makers in the long-term scenario development, cost allocation and planning processes.[40] RTOs must consider state and local resource mix and demand as well as decarbonization and electrification goals to evaluate transmission projects and upgrades across several long-term benefits. MISO and PJM must continue to consider Illinois state law when developing assumptions for their long-term planning scenarios. The long-term benefits of each scenario are evaluated for enhanced reliability, production cost savings, and mitigation of extreme weather events and unexpected system conditions. Costs are to be allocated commensurate with

---

[36] *"Effects of the One Big Beautiful Bill on Projects." July 2025. https://www.projectfinance.law/publications/2025/july/effects-of-one-big-beautiful-bill-on-projects/*

[37] *"Amendments to IRA Tax Credits in the Senate Budget Bill." White & Case. 2025. https://www.whitecase.com/insight-alert/amendments-ira-tax-credits-senate-budget-bill*

[38] *Section 301: Tariff for Li-ion non-electrical vehicle batteries increases from 7.5% to 25% for China in 2026. https://www.whitecase.com/insight-alert/united-states-finalizes-section-301-tariff-increases-imports-china*

[39] *"Transmission Planning and Cost Allocation Final Rule (Order No. 1920)." Federal Energy Regulatory Commission. https://www.ferc.gov/explainer-transmission-planning-and-cost-allocation-final-rule#_Key_Decisions_of_Order1920*

[40] *"What State Regulators Need to Know About Order No. 1920-B." Federal Energy Regulatory Commission. https://www.ferc.gov/what-state-regulators-need-know-about-order-no-1920-b-pdf*

project benefits, and states can take part in designing the cost allocation methodology. Chapter 5 further discusses how Illinois may consider leveraging Order 1920 compliant planning processes to further REAP zone development.

Major RTO Filings

The 2024 REAP report emphasized interconnection reform as a major barrier to renewable deployment in Illinois. PJM's interconnection queue delays, cascading restudies, and costly upgrades, along with MISO's limited annual queue throughput were seen as the main challenges to meeting Illinois' policy goals. The 2024 REAP recommended advocacy for RTO reforms, as detailed earlier in this Introduction. In one of the most consequential reforms since the 2024 REAP report, FERC issued Order No. 2023, requiring all RTOs/ISOs to overhaul their interconnection procedures.[41] Both MISO and PJM filed compliance plans in 2023-2024, which now frame how projects in each RTO will move through their respective queues.

PJM's Order 2023 compliance filing implements cluster-based studies instead of serial review, with a three-phase cluster study process and more stringent site control and readiness requirements for projects in the queue.[42] Readiness requirements include deposits at each phase in the cluster study process and withdrawal penalties. In addition, PJM is reforming the cost allocation for network upgrades and improving coordination of "affected system" notification and study processes, with penalties imposed if either the host or the affected system misses study deadlines. In its filing, PJM emphasized clearing its backlog before new requests can enter the post-Order No. 2023 interconnection queue process. PJM has attempted to address many of the issues highlighted in the 2024 REAP (delays, high withdrawal rates, and restudy cycles) in its compliance filing; however, PJM's slower implementation timeline compared to MISO could mean that Illinois projects in the ComEd zone continue to face uncertainty in the near term. While FERC approved most components of PJM's filing, it rejected PJM's proposal of "reasonable efforts" for timelines and has directed stronger accountability measures such as stricter study delay penalty structures that may speed up the process.[43]

The primary objective of MISO's Order 2023 compliance filing was to complete the transition to a clustered study process. This approach builds on MISO's existing three-stage Definitive Planning Phase (DPP) framework, which had already implemented elements of clustering prior to FERC Order 2023. The filing introduces modifications to ensure full alignment with the standards established in Order 2023.[44,45] Modifications include uniform study timelines, stricter readiness requirements for projects entering the queue, and higher financial commitments through study deposits and withdrawal penalties. It also enhances "affected system" coordination and imposes stricter limits on study deadlines. MISO clarified its provisions for generator deliverability and distinguishing between firm and non-firm resource interconnection services and provided additional transparency on its cost and study results.

Tracking the implementation of interconnection reform will continue to be a key priority for the ICC. These reforms provide the groundwork for improved interconnection throughput, which will be critical for Illinois to meet its policy targets.

---

[41] *"Order No. 2023." Federal Energy Regulatory Commission. May 2023. https://www.ferc.gov/media/order-no-2023*
[42] *"FERC eLibrary Filing, Accession Number 20240516-5155." Federal Energy Regulatory Commission. May 16, 2024. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240516-5155&optimized=false*
[43] *"E-2: Docket No. ER24-2045-000." Federal Energy Regulatory Commission. 2024. https://www.ferc.gov/media/e-2-er24-2045-000*
[44] *"Docket No. ER24-341-000." Midcontinent Independent System Operator (MISO). November 3, 2023. https://cdn.misoenergy.org/2023-11-03%20Docket%20No.%20ER24-341-000630772.pdf*
[45] *"Generator Interconnection Studies Portal." Midcontinent Independent System Operator (MISO). 2024. https://www.misoenergy.org/planning/resource-utilization/GI_Studies/#t=10&p=0&s=&sd=*

Load Growth from Large Load Interconnection

Large load interconnections, particularly data centers, have emerged as a major, new driver of electricity demand in Illinois since the 2024 REAP. From 2021 to 2025, PJM's year-on-year peak load growth expectation has increased from 0.2-0.3% to 2-3%, as shown in Figure 2. Similarly, MISO's 20-year peak load growth expectation has also more than doubled in recent years, as shown in Figure 3. This rapid and dramatic change in forecasted demand fundamentally alters the outlook for Illinois's power system. The surge in large, concentrated loads will strain existing grid infrastructure, requiring development of new resource and transmission capacity to serve these loads and maintain system reliability while continuing to make progress towards policy targets.

Figure 2: Evolution of PJM's Peak Load Forecasts (GW)

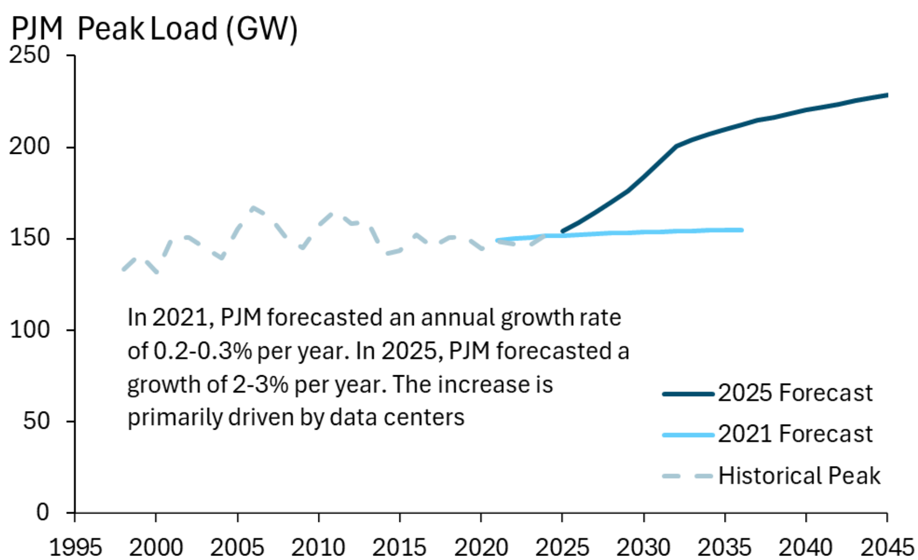
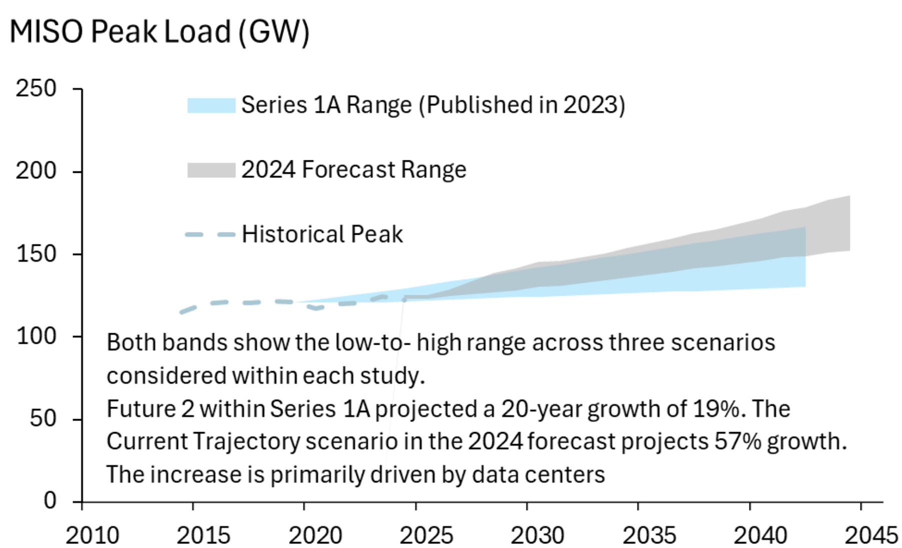


Figure 3: Evolution of MISO's Peak Load Forecasts (GW)



Evolution of REAP with the Introduction of an Integrated Planning Framework

Developing a statewide framework for renewable energy access requires a deliberate, stepwise approach. Illinois' clean energy transition is complex, spanning multiple agencies, planning jurisdictions, and data systems. As such the REAP is intentionally designed as a biennial process, rather than a one-time plan. By advancing iteratively, each cycle can refine data, strengthen modeling assumptions, and improve coordination with MISO and PJM while progressively broadening the scope and precision of its recommendations when necessary. This gradual "walk-jog-run" progression allows ICC to build durable tools that evolve in pace with changing market and policy conditions, as shown in the figure below. In the "walk" phase, the ICC defined the REAP framework in the 2024 REAP; in the "jog" phase, this current REAP refines and applies that established framework to a modeling framework to define needs; and ultimately in the "run" phase, REAP outputs are embedded in regional transmission decisions and tracking on-the-ground progress. This approach sets realistic expectations: every REAP produces durable artifacts (zones, needs statements, headroom screens, and engagement records) while also identifying opportunities for further refinement and iteration in the next cycle.

Along this trajectory, the 2024 REAP "walked" by establishing the foundation with seven initial zones, a repeatable process, and candidate regulatory pathways. The 2026 REAP (this cycle) "jogs" by refining zone definitions, introducing first-cut capacity and headroom estimates tied to the integrated modeling platform, and incorporating early resource-adequacy insights to prioritize actions. By 2028, the REAP aims to deliver well-defined zone-level capacity and transmission needs that MISO and PJM can act on, with improved headroom analysis informing targeted upgrades and any proposed new zones. From 2030 onward, ICC expects to be in the "run" phase, reporting on development within zones, ensuring REAP needs are routinely considered in long-term planning, and, where appropriate, identifying interregional opportunities, closing the loop from policy targets to delivered projects.

Figure 4: Roadmap for Successive REAP Iterations

Walk	Jog	Run
2024 REAP (Cycle #1)	**2026 REAP (Cycle #2)**	**2028 REAP (Cycle #3)**
Achievements: • Selected 7 broad REAP Zones, 5 Zones of demonstrated developer interest and 2 Future Potential Zones • Created framework of REAP process • Outlined potential regulatory processes	**Achievements to Date:** • Geocoding REAP zones • Building and demonstrating capability to model these REAP zones and optimize G&T investments • Initial assessments of optimal generation build out in each zone and broad transmission needs in select scenarios • Refine viable regulatory pathways for development of solutions to identified transmission needs and integration into RTO processes	**Anticipated Achievements:** • Further refinement of REAP zones • Higher fidelity representation of Tx constraints and upgrade options subject to data availability • Refine optimal generation and transmission buildout • Additional scenario analysis • Aim for REAP Zones to be actively considered in Long Term Planning Processes within each RTO

This 2025 Draft REAP introduces a materially new analytical foundation relative to the 2024 REAP by establishing an Integrated Planning Framework (IPF) that links resource portfolios and transmission needs within a single modeling framework. In a restructured state situated within two multi-state RTOs, planning that proceeds in isolated generation or transmission silos is unlikely to identify the most efficient, reliable, and equitable path to meeting Illinois' clean-energy objectives. This REAP therefore initiates an integrated framework designed to translate policy requirements into system needs, and to align those needs with transmission solutions administered by the RTOs.

To support this shift, the Commission's staff and consultants have developed a capacity-expansion modeling platform with a zonal representation of MISO and PJM and sub-zones within Illinois. At a high level, this approach creates one planning "through-line" for the State: common inputs, shared assumptions, and a statewide view of where and when the system will require new resources and transmission. Strategic Elements 2, 3 and 4 draw heavily from this analysis, and those chapters describe the framework and preliminary results in more detail. This framework organizes data and analysis so that policy goals become clear statements of need, supported by transparent methods and shared evidence. Strategic Element 5 in this REAP also sets out how those needs can be advanced in MISO and PJM processes, thereby creating a practical bridge from State policy to regional planning and project development.

While this constitutes a significant addition to the REAP's approach, it will not resolve all planning questions in a single cycle. Consistent with a "walk-jog-run" philosophy, this cycle focuses on standing up the framework, establishing common inputs and data standards, and producing transparent outputs, such as preliminary needs statements, that can be advanced through PJM's and MISO's planning pathways.

Future REAP cycles will iteratively improve this framework as additional information becomes available, including refined cost and performance data, detailed information regarding transmission constraints and associated upgrade costs, updated statutory or market requirements, and lessons learned from coordination with MISO and PJM. Model assumptions and outputs will be calibrated over time, with expanded data granularity and stakeholder input. In this manner, the IPF introduced in this REAP establishes the durable groundwork for a recurring, data-driven process that incrementally tightens alignment between Illinois' clean-energy objectives, resource portfolios, and the transmission solutions needed to deliver them.

Roadmap to the 2025 Draft REAP

This REAP builds directly on the foundation established in the 2024 Renewable Energy Access Plan, retaining the same five Strategic Elements but refining their focus and scope. Whereas the first REAP centered on establishing baseline analyses and identifying immediate actions to advance renewable access, this cycle emphasizes coordination across agencies, integration with ongoing studies, and alignment with emerging federal and regional planning processes. Early recommendations, such as establishing REAP zones, assessing interconnection headroom, and coordinating with RTOs, are now being operationalized through integrated analyses and targeted advocacy. In parallel, this cycle's recommendations mark areas where future iterations of the REAP will continue to evolve in response to shifting policy, market, and reliability conditions. A summary of the 2024 REAP and the 2025 Draft REAP recommendations for each Strategic Element can be found in Appendix A, as well as further context on some of the shifts in focus of certain Strategic Elements between cycles.

This REAP is organized around five Strategic Elements that collectively assess Illinois' progress toward CEJA targets, evaluate future system needs, and outline pathways to advance clean-energy infrastructure through coordinated state and regional action. **Strategic Element 1** benchmarks Illinois' progress toward its clean energy, decarbonization, and equity goals using quantitative indicators and qualitative insights. It also summarizes the stakeholder engagement and community outreach conducted during this cycle and identifies opportunities to deepen participation and improve transparency in future REAPs. **Strategic Element 2** introduces the Integrated Planning Framework (IPF), which co-optimizes generation and transmission investments to identify least-cost, reliable pathways for achieving CEJA's legislative requirements. This chapter establishes the analytical foundation for the REAP by refining REAP zones, describing key modeling assumptions, and assessing statewide resource and transmission needs across multiple scenarios.

Building on this foundation, **Strategic Element 3** examines how land-use constraints, renewable potential, and siting considerations shape the development of REAP zones and influence where clean-energy and transmission infrastructure can most cost-effectively be sited. It incorporates new geospatial datasets, land-suitability scoring, and updated zone boundaries to assess how Illinois can align renewable development with community, environmental, and system needs. **Strategic Element 4** explores how to meet the transmission needs emerging from the IPF, both through traditional network upgrades and through advanced transmission technologies and non-wires alternatives that can defer or reduce the need for new builds. Finally, **Strategic Element 5** identifies the regulatory and market pathways through which Illinois can advance these needs in MISO and PJM, evaluates how evolving federal rules (including FERC Order 1920) may create new opportunities for state-driven planning, and highlights policy tools that can support reliability and mitigate emissions leakage. Together, these Strategic Elements provide a comprehensive, iterative framework for ensuring that Illinois' clean-energy transition remains reliable, affordable, and aligned with state policy priorities.

Strategic Element 1: Tracking Progress Toward Illinois' Policy Goals

Strategic Element 1, *Tracking Progress Toward Illinois' Policy Goals*, evaluates Illinois' advancement toward the clean energy, decarbonization, and equity requirements set forth in CEJA. This chapter compiles quantitative and qualitative indicators to assess progress across renewable resource development, emissions reductions, electrification, and broader economy-wide decarbonization. In addition, this chapter highlights stakeholder and community engagement activities conducted during the current REAP cycle, reflecting input gathered through workshops, webinars, and technical working groups. Drawing on lessons from this engagement, the 2025 Draft REAP recommends additional actions the ICC can take in future REAP cycles to deepen outreach, broaden participation, and ensure that stakeholder perspectives continue to shape Illinois' clean-energy planning process.

Highlights from the 2024 REAP

Strategic Element 1 of the 2024 REAP focused on establishing the tools and processes needed to track Illinois' progress toward its clean energy and decarbonization goals. The 2024 REAP recommended that the ICC publish an annual progress report summarizing renewable deployment, emissions reductions, and overall movement toward CEJA targets. It also called for the formation of a REAP Working Group, to convene state agencies and stakeholders on a regular basis to monitor progress, share data, and identify emerging policy or implementation gaps. These actions were intended to provide continuity between REAP cycles and ensure that Illinois' renewable and transmission planning remained responsive to new information and policy developments.

The 2024 REAP also emphasized the importance of developing consistent and transparent metrics to evaluate progress across state programs, including renewable procurement, transmission development, and emissions performance. It encouraged agencies to improve data sharing and coordination so that updates to the REAP, the LTRRPP, and related studies could draw from a common evidentiary foundation. In doing so, Strategic Element 1 laid the groundwork for a more systematic and iterative planning process, ensuring that future REAPs could build upon measurable progress and adapt to evolving market and regulatory conditions.

Climate and Equitable Jobs Act

Illinois's clean energy and emissions policies have developed through a series of major legislative actions built upon the state's restructured, market-based electric system established under the 1997 Electric Service Customer Choice and Rate Relief Act. Over time, laws such as the Illinois Power Agency Act (2007), which created the Illinois Power Agency (IPA) and the Renewable Portfolio Standard (RPS), the Future Energy Jobs Act (FEJA), and the Climate and Equitable Jobs Act (CEJA) have progressively advanced the state's environmental and clean energy goals. These statutes introduced renewable and zero-emission energy targets, expanded energy efficiency and community solar programs, and established mechanisms such as Renewable Energy Credits/Certificates (RECs), Zero Emission Credits (ZECs), and Carbon Mitigation Credits (CMCs) to support decarbonization while maintaining competitive market structures. Collectively, these policies have guided Illinois toward a more reliable, equitable, and sustainable energy future grounded in both market efficiency and public policy objectives.

Enacted in 2021, CEJA, or Illinois Public Act 102-0662, represents comprehensive clean energy and decarbonization legislation, building on the foundation laid by the 2016 Future Energy Jobs Act. CEJA codified Illinois's long-term commitment to eliminate greenhouse gas emissions from large fossil units by 2045, achieve a 100 percent clean energy supply by 2050, and accelerate interim RPS targets while introducing new mechanisms to ensure an equitable transition. The law restructured and expanded renewable procurement programs such as the Adjustable Block Program and Illinois Solar for All, created new market instruments like Carbon Mitigation Credits to preserve non-emitting nuclear resources, and established programs for workforce development and community reinvestment. CEJA's reforms align clean energy deployment with affordability and reliability goals, with the aim of integrating climate, equity, and resource adequacy objectives into energy policy.

Among many policy ambitions laid out in CEJA, CEJA sets both legislative requirements as well as goals for a clean energy transition and wider decarbonization. A summary of the goals and requirements of the legislation most relevant to the REAP are described in Table 1 below.

Table 1: CEJA Goals and Legislative Requirements

CEJA Goals	Description
100% Clean Energy by 2050	Achieve carbon-free electricity and large-scale electrification of all energy systems. "Clean energy" refers to energy generation that is 90% free or greater of carbon dioxide emissions.
Electrification in Transportation	State should have one million electric vehicles (EVs) by 2030.
Solar and Wind Procurement Targets	Delivery of at least 45 million annual RECs from new solar and wind projects by 2030. At least 45% of RECs should come from wind, and 55% from solar.
CEJA Legislative Requirements	**Description**
50% Renewable Portfolio Standard by 2040	Requires REC procurements to cover 40% of load by 2030 and 50% by 2040. RPS requirements apply to Ameren and MidAmerican retail customers within MISO's footprint and ComEd retail customers within PJM's footprint. Large customers have a self-supply option that is paired with a reduced RPS charge. The RPS requirements do not apply to municipal utilities, rural cooperatives, and Mount Carmel Public Utility. Budget caps are in place to limit the incremental costs to consumers from procuring renewable energy, but such budget caps also limit utilities' ability to meet the RPS targets and goals.
Fossil Fuel Emissions Elimination by 2045	**Privately Owned Generation:** Coal and oil-fired generation must reduce emissions to zero by 2030. Gas fired generation must reduce emissions to zero by 2045, with accelerated emissions reductions based on emissions intensity, location to equity zones or equity investment eligible communities, and heat rates. Annual emissions caps in place based on 2018-2020 levels, with compliance demonstrated through rolling 12-month average emissions.

	Publicly Owned Generation: Coal and oil-fired generation must reduce emissions by 45% by 2035, with an extended deadline of 2038, and to zero by 2045. Gas fired generation must reduce emissions to zero by 2045, with no phaseout schedule. All legislative requirements apply to generating units over 25 MW. Private and publicly owned gas generating facilities can either retire or convert to 100% green hydrogen or similar technology to comply. Exceeding emissions restrictions is allowed in certain instances if the RTO in which the facility participates determines that the facility is necessary to maintain power grid supply and reliability or the facility is a necessary emergency backup to operations.
Utility Electrification Plans	Utilities serving greater than 500,000 customers in the State are required to file a Beneficial Electrification Plan, primarily providing programs that foster electric vehicle adoption, with ICC for programs starting by January 2023.
Nuclear Resource Retention	Authorizes CMC payments through mid-2027 to sustain Illinois' existing nuclear fleet. CEJA authorizes CMC credits for nuclear facilities in PJM. CMC-contracted facilities include Braidwood Units 1 and 2, Byron Units 1 and 2, and Dresden Units 2 and 3.

CEJA also centers on equity in the energy transition and sets specific goals and legislative requirements near EJ communities and areas eligible for equity investment. Privately-owned natural gas fired generating facilities face accelerated emissions reduction schedules within three miles of an EJ community or eligible equity investment area, with high emitting facilities (NO_x emissions over 0.12 lbs/MWh or SO_2 emissions over 0.006 lb/MWh) retiring or transitioning to green hydrogen by 2030, and other facilities reducing emissions by 50% by 2030 and fully by 2035. The legislation also aims to lead local governments to establish workforce development programs and job-training opportunities for disadvantaged workers and provide low-interest financing and direct capitalization for these communities through upfront grants.

Findings

Current Status of Progress towards CEJA Goals

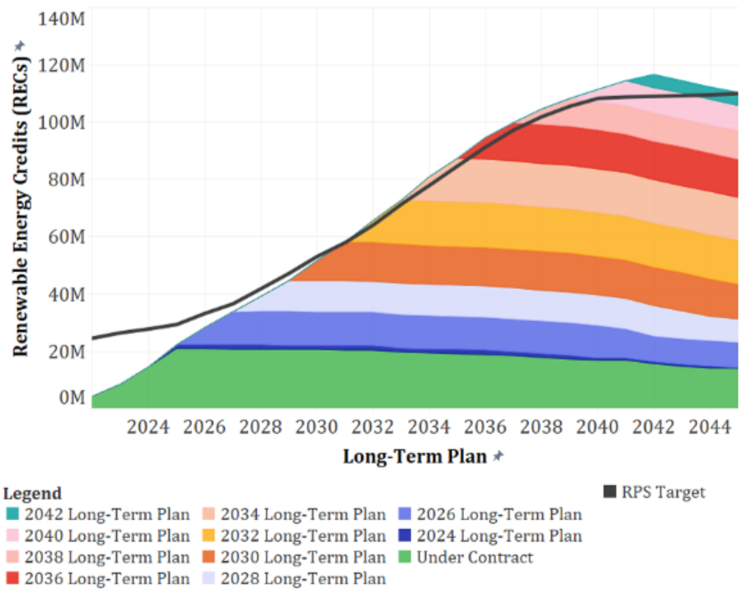
Renewable Energy Resource Development Goals

The Illinois RPS has the goal of matching 25% of retail load with RECs by 2025, with that goal increasing to 40% in 2030 and 50% in 2050. As of August 15, 2025, the IPA has procured RECs for the utilities to meet 23% of utility load.[46] Through the remainder of 2025 and the first half of 2026 the IPA will continue to implement the programs and procurements authorized in the 2024 Long-Term Plan. At the time of this REAP Draft, the IPA is in the development and approval process of the 2026 Long-Term Plan which will lay out how the IPA will continue to procure RECs for the 2026-2027 and 2027-2028 delivery years.

[46] *Draft 2026 Long-Term Renewable Resources Procurement Plan (August 15, 2025). https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20250815-draft-2026-long-term-renewable-resources-procurement-plan-august-15-2025.pdf*

To meet the Illinois RPS' goals, the IPA will need to continue to expand programs and procurements. However, as the IPA has noted over a series of RPS Budget Updates and Long-Term Plan budget analyses,[47] the current structure of funding for the Illinois RPS is insufficient to support the level of procurement needed to meet those goals. Figure 5 shows how programs and procurement are conducted to date, and those projected to be needed to meet the Illinois RPS.

Figure 5: Current and Future Expected REC Procurement Volumes[48]



A challenge for meeting the RPS targets has been the rapid change in future load forecasts over the past year as the impact of the increased electric demand from data centers has been incorporated into planning forecasts. For example, in the 2024 REAP the 2030 40% RPS goal was forecast to be 46.5 million RECs, but the increase in load forecasted has changed that 40% RPS goal in the 2025 draft REAP to 53 million RECs, and the 2040 50% RPS goal had been 60.6 million RECs in 2024 REAP, but it is now forecast to be 108 million RECs.

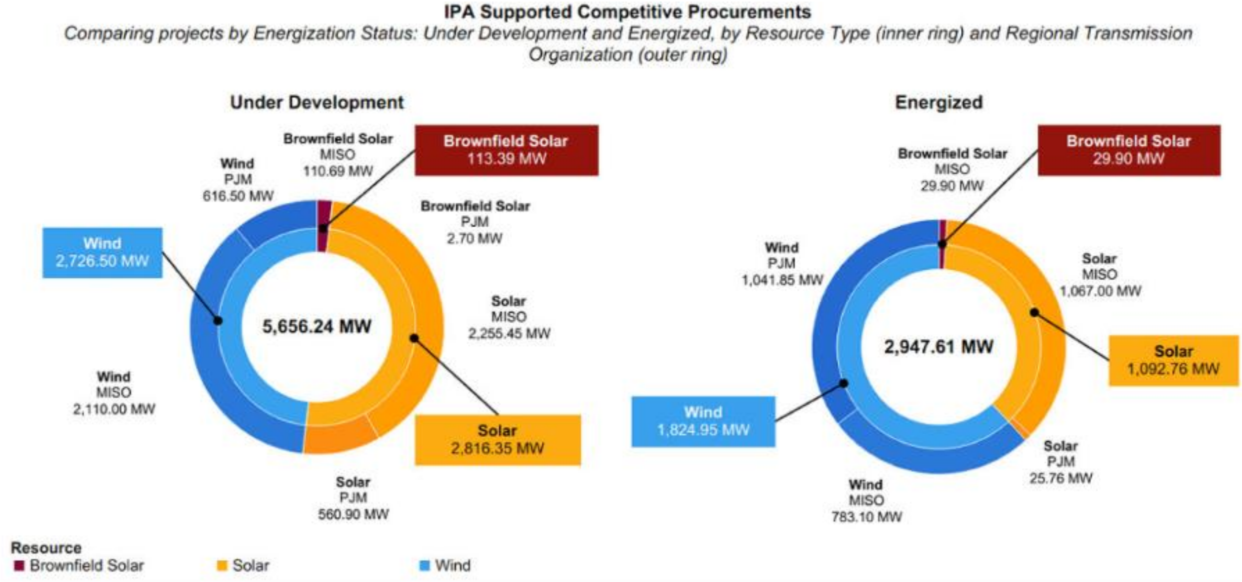
The Illinois RPS allows for certain renewable resources in adjacent states to Illinois to qualify. The IPA developed a public interest criteria for adjacent state renewable resources that does factor in the deliverability of power to Illinois, however that criteria is broad in scope and not closely tied to ensuring reliability in Illinois.[49] For the Indexed REC procurement conducted by the IPA in 2022 through 2025, 14% of the RECs procured have come from utility-scale wind or solar resources in adjacent states.

As of August 2025, IPA Procurements of utility-scale resources have supported the development of 2,947.61 MW of utility-scale renewable energy resources with an additional 5,656.24 MW of projects under development, as seen in Figure 6. While the majority of resources that have been energized are wind, there is currently slightly more utility-scale solar under development than utility-scale wind.

---

[47] *Illinois Power Agency Updated Renewable Portfolio Standard Budget Forecast (May 12, 2025).* *https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/rpsbudgetupdate51225.pdf*
[48] *Appendix B: RPS Budget and REC Portfolio Spreadsheet, Illinois Power Agency, August 2025.*
[49] *20 ILCS 3855/1-75(c)(1)(I)*

Figure 6: IPA Supported Competitive Procurements



In addition to utility-scale resources, the IPA has supported the development of photovoltaic distributed generation and community solar projects with over 1,600 MWs of projects energized and approximately 1,800 MW of projects under development. Figure 7 and Figure 8 show how Illinois Shines and Illinois Solar for All operate on a rolling application basis and the amount energized continues to grow.

Figure 7: Illinois Shines Under Development and Energized Resources

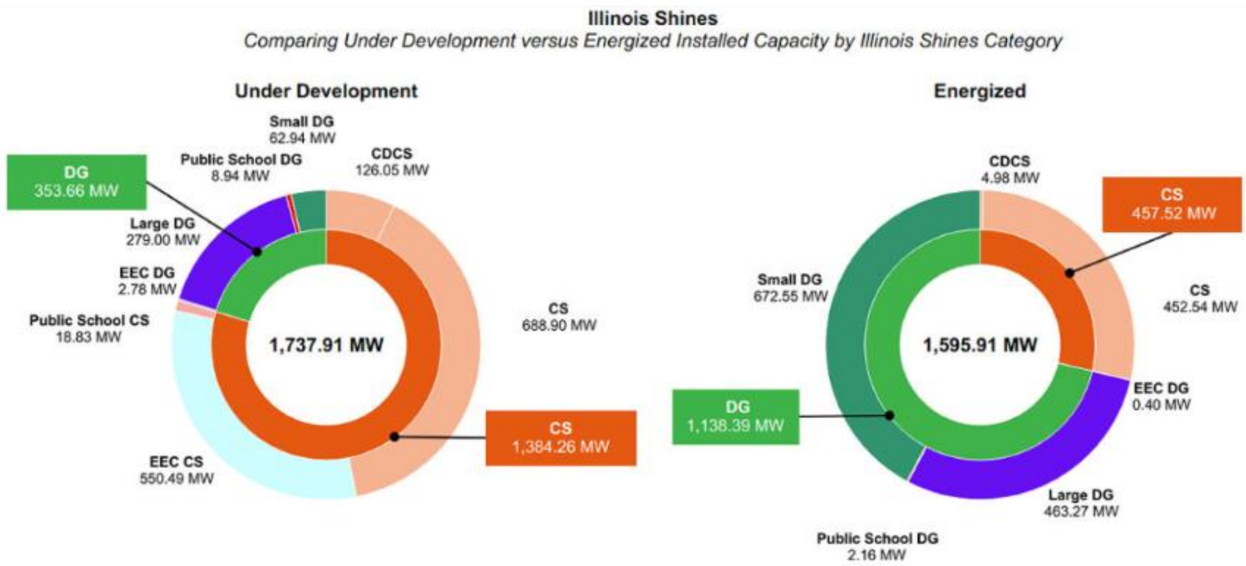
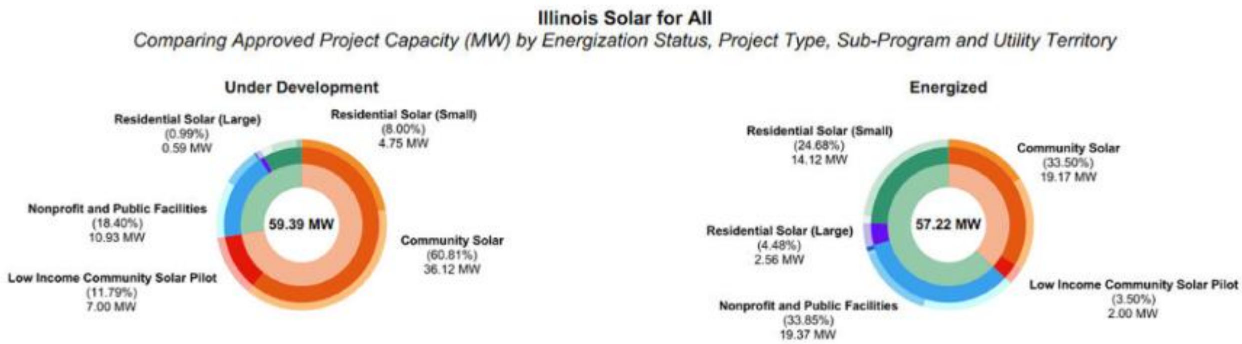


Figure 8: Illinois Solar for All Under Development and Energized Project Categorization



While the Illinois RPS and the programs and procurements conducted by the IPA have been vital to the development of renewable energy resources in Illinois, it should be noted that not all resources in Illinois have been supported by the RPS. For example, there is 32.9 MW hydroelectric and 55.2 MW of biomass operating in Illinois that have not been supported by RPS, and of the over 7,800 MW of wind projects in Illinois, only 15.5% have been supported by the Illinois RPS. Solar generation is more reliant on the RPS, with 46.96% of the 2,390 MW of utility-scale solar and 94.9% of the 1,36 MW of distributed generation and community solar supported by the Illinois RPS.

Developers of renewable energy projects in Illinois have a variety of reasons for not having the project participate in the RPS and thus not be counted to the state's renewable energy goals. The Illinois RPS is based on Illinois utilities buying the RECs from projects and retiring those RECs to ensure that the utility retains the rights to the environmental attributes of the energy that was generated to support the RECs. Some developers have sold the RECs from their projects to RPS compliance programs in other states, while other developers have sold the RECs to corporate buyers to help those entities meet their sustainability goals.

Fossil Fuel Phase Out

Energy sector fossil fuel emissions in Illinois have declined over the last decade due to a number of market and regulatory factors. While the first mandated zero emission deadlines under CEJA for large greenhouse gas emitting units are not until 2030, CEJA requirements limiting those units to their previous existing emissions also ensure emissions are not increasing prior to those dates and that emissions from retiring fossil fuel units cannot simply be shifted to other fossil fuel units in Illinois.

In the four years since CEJA became law, all of the large greenhouse gas emitting units that are potentially subject to the law have been identified and an inventory of their emissions was compiled by Illinois EPA in the first *Annual Greenhouse Gas Emissions Report for Sources Subject to the Illinois Climate and Equitable Jobs Act – 2024,* required under 415 ILCS 5/9.15(n). It is anticipated that units at five of the seven remaining operating coal-fired power plants in Illinois will be retired prior to January 1, 2030. It is also likely that up to 13 of the 27 operating natural gas-fired power plants in Illinois will also be retired by that date. There is some potential variance in these outcomes to the extent that zero emissions target dates may change with changes in individual plant NO_x and SO_2 emission rates, with changes in area equity eligible investment community designations, or with changes in plant heat rates.

CO_2e & Co-Pollutant Emissions Reduction

Emissions of GHG and co-pollutants from electric generation have been declining in Illinois for some time, and that trend has continued since the enactment of CEJA. These co-pollutants include sulfur dioxide (SO_2), oxides of nitrogen (NO_x), volatile organic material (VOM), and carbon monoxide (CO) from electrical generation. Below, Table 2 shows the CO_2 and co-pollutant emission reductions since CEJA was signed into law in 2021, and the percentage reduction of those pollutants in 2024, the most recent full calendar year that data is available.

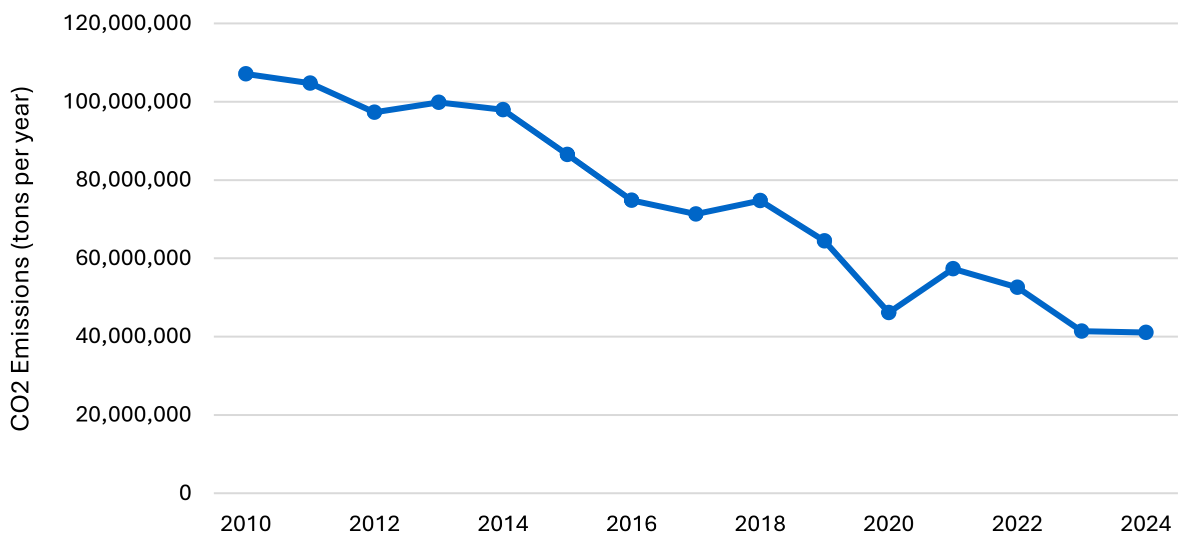
Table 2: Illinois CO_2 and Co-pollutant Emissions Reductions since CEJA

	CO2	NOx	SO_2
2021	57,315,745	23,195	46,333
2024	41,052,125	11,941	22,874
% Reduction	28.4%	48.5%	50.6%

All data in tons per year. Calculated based on facility reported data submitted to the US Environmental Protection Agency.

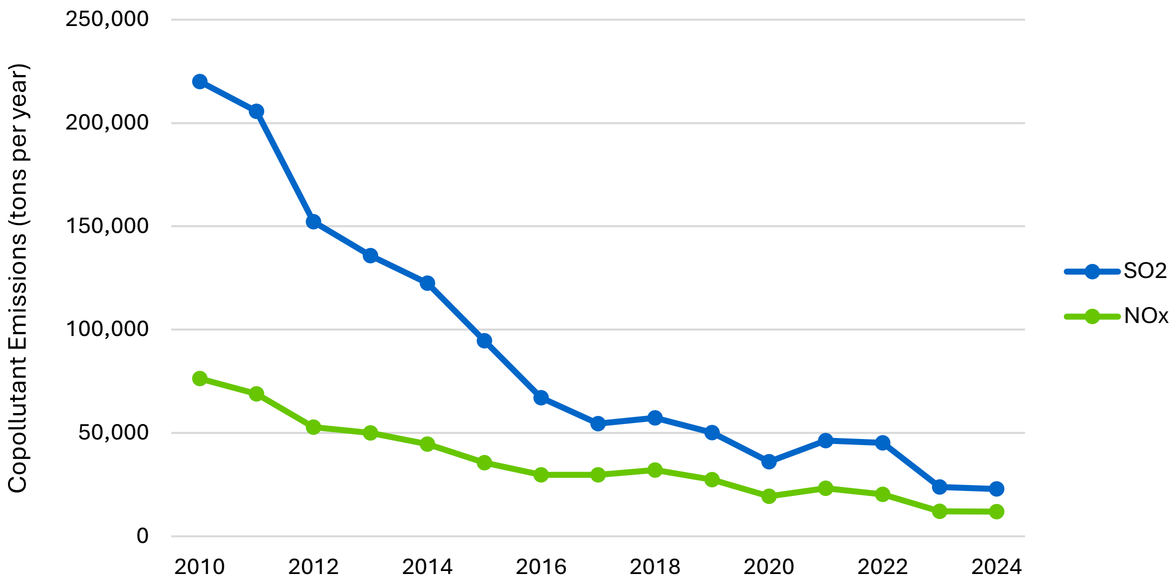
Figure 9 and Figure 10 illustrate emissions reductions from the power sector from 2010-2024. The charts show CO_2 emissions and the most commonly tracked co-pollutants, NOx and SO_2.

Figure 9: CO_2 and most Common Co-pollutant Emissions (2010-2024)[50]



[50] *Illinois Department of Commerce & Economic Opportunity Hydrogen Economy Task Force 2024 Annual Report: https://dceo.illinois.gov/content/dam/soi/en/web/dceo/aboutdceo/reportsrequiredbystatute/2024-hetf-annual-report.pdf.*

Figure 10: Common Co-pollutant Emissions (2010-2024)[51]



Green Hydrogen Technology Development and Implementation

Section 9.15(f) of the Environmental Protection Act defines "green hydrogen" as power generation using electrolytic hydrogen created solely from 100% renewable or zero carbon emission energy sources, producing zero emissions. Sections 9.15(i), (j), and (k) allow emissions reductions at large gas-fired and combined heat and power units from "... the use of 100% green hydrogen or other similar technology that is commercially proven to achieve zero carbon emissions."

Subsequent to the effective date of CEJA, the Hydrogen Economy Act created the Hydrogen Economy Task Force to (1) develop a state plan and leverage federal funding for a hydrogen hub; (2) identify opportunities to use hydrogen in energy, transport and industry; (3) assess barriers to deployment, especially in environmental justice communities; and (4) recommend supportive policies.

The Hydrogen Economy Task Force report identified two clean hydrogen incentives as key to project viability, the Federal Section 45V Clean Hydrogen Production Tax Credit and the Illinois' state tax incentive for the use of qualifying hydrogen. The report states "these credits can make clean hydrogen projects in Illinois attractive to investors; without them, most clean hydrogen projects are not likely to be viewed as economically feasible."[52] However, Federal Public Law 119-21 (2025) shortened eligibility for the 45V credit to projects beginning construction by December 31, 2027, which the Task Force warns may make many Illinois projects infeasible.[53]

The Midwest Alliance for Clean Hydrogen (MachH2) brings together partners from Illinois, Indiana, Michigan, Missouri and Wisconsin to develop large-scale hydrogen projects. On October 13, 2023, MachH2 announced that it was selected by the US Department of Energy's Office of Clean Energy Demonstrations (OCED) to

---

[51] *Ibid.*
[52] *Ibid.*
[53] *Federal Public Law 119-21 (2025): https://www.congress.gov/119/plaws/publ21/PLAW-119publ21.pdf.*

develop a Regional Clean Hydrogen Hub (H2Hub).[54] MachH2 was awarded up to $1 billion of Federal cost share for Midwest H2Hub, expected to produce tens of thousands of metric tons of hydrogen annually and create about 12,000 direct jobs.[55, 56] Recent reports, however, note uncertainty about sustained federal support.

Despite reductions in federal support, there remains potential to develop clean hydrogen technologies in Illinois. As reported in "An Atlas of Carbon and Hydrogen Hubs for the United State Decarbonization" published by the Great Plains Institute (GPI), there are currently six hydrogen-producing facilities in Illinois, five of which, GPI notes, are generally clustered in an areas of industrial activity and fossil fuel use.[57] Research institutions such as GTI Energy in Des Plaines and the University of Illinois Department of Environmental Engineering are also advancing hydrogen production, storage and infrastructure computability studies.[58,59] As GPI notes, "[c]lusters of hydrogen production and fossil fuel demand can facilitate technology deployment and jumpstart the transition to hydrogen."

Stakeholders are also exploring the use of clean hydrogen for energy production, particularly for large industrial customers, within the Commission's Future of Gas proceeding.[60] This exploration has highlighted work being done in Illinois by entities such as GTI Energy and includes development of pilot projects that could further inform hydrogen usage for Illinois energy generation.[61]

While research and exploration of clean hydrogen technologies continue in Illinois, there are no current independent power producers or electric utilities using hydrogen to fuel utility-scale generation in Illinois. There is also no current infrastructure in Illinois for the transmission of hydrogen to such generation. More work is, therefore, necessary before Illinois is positioned to widely deploy clean hydrogen in the Illinois energy economy.

Economy Wide Decarbonization and Beneficial Electrification Targets

Economy wide decarbonization is key to Illinois' climate goals. It is a multi-faceted endeavor including strategies involving electric vehicle adoption and other transportation measures, building electrification, grid modernization, expansion of renewable energy resources, and promotion of energy efficiency.

Building electrification focuses on replacing natural gas, oil, and wood-based heating and water systems with electric heat pumps and heat pump water heaters to reduce GHG emissions from residential and commercial buildings. To this end, Illinois continues to develop and implement robust building regulations and policies. Improving energy efficiency in buildings and across sectors is also crucial for decarbonization and reducing energy consumption. Illinois has consistently ranked among the top states for LEED-certified buildings per capita.[62]

---

[54] *Midwest Alliance for Clean Hydrogen Press Release (2023): https://machh2.com/oced/.*
[55] *Gulf Coast and Midwest Hydrogen Hub Announcement: https://www.energy.gov/articles/biden-harris-administration-announces-awards-22-billion-two-regional-clean-hydrogen-hubs.*
[56] *Ibid.*
[57] *Great Plains Institute Carbon and Hydrogen Hubs Atlas (2022): https://scripts.betterenergy.org/CarbonCaptureReady/GPI_Carbon_and_Hydrogen_Hubs_Atlas.pdf*
[58] *GTI Energy, "World-class R&D and Technology Deployment to Enable the Hydrogen Economy". https://www.gti.energy/hydrogen-technology-center/.*
[59] *UIUC, "Hydrogen Storage". https://isgs.illinois.edu/research/hydrogen-storage/.*
[60] *ICC Future of Gas Proceedings: https://icc.illinois.gov/programs/Future-of-Gas-Workshop.*
[61] *GTI Energy, "RNG and Hydrogen – Opportunities for Decarbonization". ICC Future of Gas Proceeding (1/13/2025). https://www.documentcloud.org/documents/25953013-gti-energy-icc-future-of-gas-1-13-25-rng-hydrogen-opportunities-for-decarbonization/.*
[62] *U.S. Green Building Council's annual Top 10 States for LEED: https://www.usgbc.org/top-10-leed-2024*

To advance decarbonization, Illinois has mobilized approximately $1B in green building financing and investments, combining efforts from the Illinois Climate Bank ($250M), utilities ($400M+), federal grants (~$200M), and CEJA-sponsored initiatives ($1M+). Illinois is leveraging funding to support renewable energy and grid modernization, accelerate clean and efficient building adoption, deploy clean transportation and freight measures, support industrial decarbonization, and expand climate-smart agricultural practices.

With respect to the transportation sector, CEJA states, within Section 45 of The Electric Vehicle Act [20 ILCS 627/45] that "Illinois should increase the adoption of electric vehicles in the state to 1,000,000 by 2030." To facilitate achievement of this goal, Section 45 requires Ameren Illinois and ComEd to file Beneficial Electrification Plans with the Commission and to periodically update the plans. The Beneficial Electrification Plans address, among other things, make-ready investments, incentives for charging equipment and electric vehicles, and enabling rates structures and optimized charging programs to facilitate deployment of electric vehicle adoption throughout the State.

As of October 2025, there are 156,425 electric vehicles registered in the State of Illinois according to the Secretary of State.[63] This is a 370% increase over the number of EV's registered when CEJA passed in September 2021 (33,343 electric vehicles).[64]

Ameren Illinois' initial Beneficial Electrification Plan was filed in June of 2022 and approved through a series of Commission Orders between March 23, 2023 and July 13, 2023.[65] The initial plan covers years 2023 – 2025.[66] Ameren Illinois' Beneficial Electrification Plan 1 2025 Annual Report contains a summary of its programs and program metrics through 2024.[67] For example, Ameren Illinois' Residential ChargeSmart Program includes bill credits, preferred charging period delivery credits, peak hourly delivery charges, and charger rebates for equity-investment-eligible or low-income customers. Ameren Illinois estimates that through 2024 this program supported 3,254 electric vehicles and 3,379 charging ports.[68] Similarly, Ameren Illinois estimates its Non-Residential ChargeSmart Program supported 13 charging ports through 2024. These and Ameren Illinois' full Beneficial Electrification Plan 1 measures and estimated impacts are summarized in the Annual Report.

ComEd's initial Beneficial Electrification Plan was filed in July of 2022 and approved through a series of Commission Orders between March 2023 and May 2023.[69] The initial plan covers years 2023 – 2025.[70] ComEd's Beneficial Electrification Plan 1 2024 Annual Report contains a summary of its programs and program metrics through 2024.[71] For example, ComEd estimates that its EV Charger and Installation Sub-Program supported 2,361 charging ports through 2024. It estimated its EV Dealer Network Program to have incented 172 electric vehicles through 2024.

---

[63] *IL Electric Vehicle Statistics (10/15/2025): https://www.ilsos.gov/content/dam/departments/vehicles/statistics/electric/2025/electric101525.pdf*

[64] *Ibid.*

[65] *Ameren filed its initial plan in Docket Nos. 22-0431 and 22-0443 (consolidated).*

[66] *See https://www.icc.illinois.gov/docket/P2022-0431/documents/340139/files/593399.pdf for Ameren Illinois' Beneficial Electrification Plan 1.*

[67] *Ameren Illinois Beneficial Electrification Plan 1 (2025 Annual Report): https://www.icc.illinois.gov/docket/P2022-0431/documents/363430/files/636427.pdf.*

[68] *Ibid., p.8.*

[69] *ComEd filed its initial plan in Docket Nos. 22-0432 and 22-0442 (consolidated).*

[70] *ComEd Beneficial Electrification Plan 1 (May 2023): https://www.icc.illinois.gov/docket/P2022-0432/documents/338224/files/589765.pdf.*

[71] *ComEd Beneficial Electrification Plan 1 (2023-2025) 2024 Annual Report: https://www.icc.illinois.gov/docket/P2022-0432/documents/363473/files/636492.pdf.*

Recently, both utilities filed and received approval for their second beneficial electrification plans. Both plans modify the initial plans to address learnings to date and will be applicable for the years 2026 – 2028.[72,73]

While the utility beneficial electrification programs are relatively new, they and other state and federal electric vehicle incentive programs have the potential to increase electricity use in the transportation sector over time.

With respect to building electrification, CEJA amended both Ameren Illinois' and ComEd's electric energy efficiency programs to explicitly allow for the inclusion of electrification measures. In particular, the utilities are permitted to count toward their appliable annual total savings requirements electrification savings up to 5% per year from 2022-2025, up to 10% per year from 2026-2029, and 15% thereafter. In 2024, Ameren Illinois included among its energy efficiency programs, a program providing income qualified customers whole home projects that feature the displacement of propane-fired appliances and mechanicals in favor of high-efficiency electric appliances and mechanicals.[74] ComEd similarly provided within its energy efficiency portfolio a program to convert income-eligible single family and multi-family homes and buildings to all-electric using highly efficient technologies.[75]

As with utility beneficial electrification programs, the programs offered pursuant to the new electrification measures in CEJA are relatively new. They and other state and federal building electrification programs have the potential to increase electricity use in the building sector over time.

Stakeholder & Community Engagement

Due to the broad range of communities and stakeholders potentially affected by the REAP, stakeholder feedback is a critical component of the REAP planning process. To ensure participation within a limited timeframe and budget, ICC Staff have expanded its Community Outreach Plan to engage a diverse cross-section of stakeholders statewide and ensure their perspectives inform the REAP's development and outcomes.

During this REAP cycle, the ICC began outside engagement efforts in January 2025 with the first of five Stakeholder Engagement Workshops, including one Stakeholder-led Presentations Workshop, two Technical Working Group meetings, and a Community Outreach Lunch-and-Learn webinar for a total of eight outreach events. Participation in these virtual meetings ranged from 30 to 60 attendees.

Stakeholder Engagement Workshops

As indicated by Table 3, the ICC Staff and Consultant teams hosted eight stakeholder events in 2025. Stakeholders submitted written comments for all workshops via e-mail or through a virtual comment form. Stakeholder Engagement Workshop #4 was a stakeholder-led meeting with four individual presentations and did not have an associated comment form. This section provides a brief summary of the topics and feedback received in each Stakeholder Workshop. Readers can visit the REAP Website to access the full set of stakeholder questions, written responses, presentation materials, and recordings of all stakeholder meetings conducted throughout the REAP cycle.

---

[72] *ComEd Beneficial Electrification Plan 2 (2026-2028): https://www.icc.illinois.gov/docket/P2024-0484/documents/366102/files/641295.pdf.*

[73] *Ameren Illinois' Beneficial Electrification Plan 2 (2025): https://www.icc.illinois.gov/docket/P2024-0494/documents/366191/files/641613.pdf.*

[74] *Ameren Illinois Q4 2024 Energy Efficiency Program Quarterly Report: https://www.ilsag.info/wp-content/uploads/PY2024-Ameren-Illinois-Quarterly-Report-Q4-2024_FINAL.pdf.*

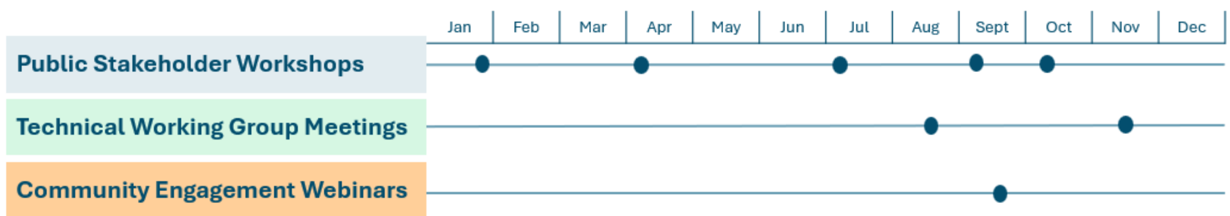
[75] *ComEd Q4 2024 Energy Efficiency Program Report: https://www.ilsag.info/wp-content/uploads/CY2024-Q4-ComEd-EE-Report.pdf.*

Table 3: REAP Cycle #2 Stakeholder & Community Engagement Workshops

Workshop Number	Topic	2025 Date	Virtual Attendees	Number of Respondents
SE - 1*	Structure of REAP Workshops	January 31	10	10
SE - 2	Analyzing & Refining REAP Zones	July 1	55	9
SE - 3	Scenarios for Getting to 100% Clean Energy and Transmission Planning	August 18	58	3
SE - 4	Stakeholder-led Presentations	September 9	51	2
SE -5	Leveraging Regional Processes and Markets	October 5	38	3
CE - 1	Community Engagement Webinar: The REAP Process	September 29	33	3
TWG – 1	REAP Zones and Modelling Framework	August 26	13	N/A
TWG - 2	REAP Assumptions and Draft Results	November 5	12	N/A

**January 2025 meeting facilitated by ICC Staff without consultants*

Figure 11: Timeline of Stakeholder Engagement



Stakeholder Workshop #1 focused on a review of the REAP Strategic Elements and invited comments on the additional Stakeholder Engagement Workshops planned throughout 2025. Ten respondents returned e-mail responses to ICC Staff's request for comments on the format and topics for the REAP Working Groups. Respondents included retail energy suppliers and transmission organizations, advocacy organizations, as well as a renewable energy producer and an analytics software company. The energy suppliers and transmission organizations emphasized reliability, transmission planning, policy coordination, and data-driven decision-making as key focus areas for the REAP. Advocacy organizations also identified reliability, collaboration, and data and metrics as key areas, and also highlighted equity, land use, cost and affordability. The other respondents mentioned innovation and strategic planning in their comments, while also echoing equity and community engagement and data-driven decision-making.

Stakeholder Workshop #2 briefly reviewed the REAP zones that were identified in REAP Cycle #1 and introduced the Integrated Planning Framework approach. Eight virtual comment forms were submitted. Stakeholders identified a clear, stable policy framework as essential to attract investment and that reliability should be prioritized through upfront capacity planning and alignment with Illinois policies. There was indication that better coordination across MISO and PJM, use of surplus interconnection capacity, and repurposing brownfield locations would facilitate new development. Commenters suggested that land use and siting should emphasize protecting sensitive lands while utilizing as much existing transmission infrastructure as possible. Stakeholders also noted that model zoning ordinances and expedited permitting are needed to reduce delays in transmission planning and implementation. Stakeholders called for transparent, localized outreach that aligns with REAP outreach to other Illinois energy initiatives to improve inclusivity and efficiency.

Stakeholder Workshop #3 provided greater detail on the Integrated Planning Framework approach and how scenario design focused on external drivers with high impact and high uncertainty help to explore multiple possible futures. Virtual comment request asked for feedback on which policy considerations and infrastructure factors should be considered in this REAP Cycle to develop the core scenarios. Four virtual comment forms were returned with comments. The respondents indicated that all infrastructure factors are essential and should remain as priorities. They indicated that supply chain issues and siting and permitting delays were high impact, high uncertainty challenges that could substantially hinder progress. Commenters also indicated that key technologies (e.g., storage, DERs, and GETs) were vital for reducing transmission needs, lowering overall system costs, and enhancing grid resilience. Concerns over the uncertainty of large load additions from data centers and industrial growth within and adjacent to Illinois were raised by several commenters as well. Comments also indicated that REAP scenario modeling was crucial for evaluating trade-offs and shaping effective, actionable energy policies that would ensure reliability, affordability, and sustainability.

Stakeholder Workshop #4 was stakeholder-led with four presentations from Bekaert, Union of Concerned Scientists, Clean Grid Alliance, and the Environmental Law and Policy Center. Bekaert's presentation was on *Increasing Illinois Grid Capacity with Advanced Steel Core Conductors Using Existing Transmission Infrastructure*. The Union of Concerned Scientists presented on *MISO Tranche 2.1*. The Clean Grid Alliance along with Jupiter Power, presented *Leveraging REAP as an Actionable Tool to Support CEJA's 2030 Goals Amidst Federal Policy Changes*. The Environmental Law and Policy Center presented on *Implementing Advanced Transmission Technologies in Illinois*. These presentations provided an overview of methods to increase efficiencies across existing transmission infrastructure, the impact of external policy and agency regulations, guidance, planning, and implementation on Illinois renewable energy goals, and how ATTs can be used by existing utilities to relieve transmission issues.

Stakeholder Workshop #5 provided information on leveraging regional transmission planning processes and ATTs. Three virtual comment forms were received covering the remaining challenges and next steps for interconnection reforms, regulatory pathway trade-offs, ATT recommendations, and opinions to determine if this REAP Cycle was successful. Respondents indicated that clearing the interconnection backlog is foundational, while improving individual RTO coordination and addressing Illinois' unique position within both MISO and PJM requires cross-coordination to meet statewide goals. Stakeholders also noted that they want REAP to move beyond identifying barriers toward driving measurable outcomes, such as numerical benchmarks and performance metrics tied to generation throughput, address distribution-level constraints, and maintain adaptability to evolving RTO processes. While no new major pathways were suggested, stakeholders emphasized integrating REAP needs into evolving RTO regulatory processes, clarifying cost allocation and gave feedback on regulatory pathways for right-sized projects. Stakeholders generally supported ATT adoption but cautioned against unnecessary pilot programs and emphasized addressing energy provider confidentiality and proprietary challenges in implementation. Stakeholders want REAP to remain dynamic and action-oriented, with measurable progress and strong coordination, while recognizing its limitations in influencing RTOs.

Community Engagement Webinar

To create an educational and collaborative environment that encouraged community-level participation, a Community Engagement Webinar was hosted. Materials were presented in plain language (i.e., clarifying or removing terminology that might only be familiar to those who work in the energy sector) and the meeting was framed as a Lunch-and-Learn. More than 70 invitations were sent out to organizations, interest groups, and individuals that had interacted with the ICC staff previously for other energy-related issues. Approximately 30 people attended the Lunch-and-Learn webinar on September 29, 2025. Comments indicated that stakeholders were not engaged or aware of the REAP process, and therefore the webinar helped expand awareness of the REAP planning process. Feedback from the webinar informed the recommendations below on how the ICC staff could move forward with Community Engagement in future REAP cycles.

Technical Working Group

In addition to the stakeholder workshops and community engagement webinar, the expertise of experts across the energy sector including within and outside of Illinois was sought through a Technical Working Group (TWG). Participants in the Technical Working Group spanned Illinois state agencies, utilities, RTOs, independent power producers and advocates. In the first meeting, key assumptions feeding into the IPF this cycle were covered in detail to gather feedback from TWG members. The second TWG covered draft results. No comment forms were requested to be filled after the meetings, however feedback was received during the live questions and answer session and additional feedback was welcomed over email, but none was received.

Recommendations

Stakeholder Engagement

Looking toward future REAP cycles and building from the outcomes of this REAP Cycle, the ICC envisions enhanced stakeholder outreach in each cycle that deepens engagement and outreach to potentially impacted communities. In the next cycle, ICC plans to continue to host stakeholder workshops and facilitate a Technical Working Group, whose expertise and feedback strengthen the REAP. ICC Staff and Consultants will work to continue to give advanced notice of upcoming meetings, provide opportunities for live discussion of REAP topics, and ask stakeholders for feedback after each meeting to integrate into the REAP.

Expanded community engagement will be improve upon in future cycles. This could include conducting more virtual Lunch-and-Learn webinars focused on key REAP topic areas inviting communities, neighborhoods, rural areas, and diverse populations in those areas to these webinars. Additionally, ICC Staff will consider how to engage and partner with community champions, such as neighborhood associations, chambers of commerce, councils of government, non-governmental organizations with a diversity focus, Illinois Farm Bureau, agricultural cooperatives, and other organizations and individuals, that could disseminate information to their members/stakeholders, as well as increase awareness and avenues to provide specific information.

In-person community engagement is possible in future REAP cycles, but it is conditional on staffing and funding. Whether or not there are resources for in-person engagement, the ICC can leverage its web and social networking presence with a dedicated REAP community engagement website that would provide appropriate materials to help inform citizens about the REAP, the components within each REAP cycle, and engagement opportunities.

Strategic Element 2: Transitioning to a Decarbonized Electricity Mix

Strategic Element 2, *Transitioning to a Decarbonized Electricity Mix*, outlines how Illinois can plan, model, and coordinate the generation and transmission investments required to meet CEJA's legislative requirements reliably and cost-effectively. This chapter introduces the Integrated Planning Framework (IPF), describing how it refines REAP zones, co-optimizes generation and transmission, and integrates resource adequacy considerations to identify long-term system needs. It then summarizes the key modeling assumptions, such as load growth, system topology, and scenario design, that shape Illinois' future resource mix. Building on this foundation, the chapter analyzes statewide preliminary findings across multiple scenarios, highlighting the renewable, storage and firm capacity builds selected under varying policy pathways. Finally, the chapter outlines recommendations for expanding scenario analysis, improving data alignment with utilities and RTOs, and enhancing the treatment of NWAs and ATTs, setting the stage for subsequent chapters in this report that will cover zone-level results and regulatory pathways to fill these needs.

Highlights from the 2024 REAP

Strategic Element 2 of the 2024 REAP examined what Illinois needed to do to transition from its existing electricity mix toward CEJA's 100% clean electricity goal. The 2024 REAP found that while the RPS, nuclear support programs, and the fossil-emissions phaseout set important foundations, they did not ensure that all of Illinois load would be served by clean resources after nuclear support expired in 2027. Achieving a reliable, affordable clean mix required coordinated state policies and regional market reforms that created stronger investment signals and reduced dependence on the interconnection process to expand transmission. The 2024 REAP emphasized that increasing upgrade costs and delays in MISO and PJM queues were major barriers that proactive, scenario-based transmission planning needed to address.

Advancing Illinois' Planning Approach

The 2024 REAP identified the value of proactive transmission planning and co-ordination with the RTOs given Illinois' unique position as a restructured state in two separate multi-state RTOs. This 2025 REAP develops an integrated generation and transmission planning framework. This framework spans the entire state, co-optimizing generation and transmission to identify transmission system needs that support cost-effective achievement of the state's policy goals. Coordination with the RTOs remains key, and needs identified with the framework can be used to inform region-wide RTO planning processes to ensure cost-effective solutions are identified to fill those needs. The rest of this chapter will detail how needs can be identified with the IPF. Chapter 5 describes the potential regulatory pathways to fill those needs through regional planning and collaboration with the RTOs.

Table 1 describes CEJA goals and legislative requirements. In this REAP cycle, preliminary resource and transmission needs were estimated to meet the CEJA *legislative requirements* of 50% RPS by 2040 and fossil fuel phaseout by 2045. Notably, the 100% clean energy *goal* by 2050 was not modeled. Increases in electricity demand driven by electrification of "all energy systems" will have significant impacts on resource development and transmission system needs in Illinois. Though these impacts were not examined within this REAP cycle, the IPF is designed to be able to do so. The IPF can take different electrification load forecasts and explore multiple policy scenarios in the future, including scenarios that go beyond *legislative requirements* to achieve the state's broader economy-wide clean energy *goals*.

It is also notable that clean energy in CEJA refers to "energy generation that is 90% free or greater of carbon dioxide emissions". Two of the three scenarios in this REAP do not restrict imports that may come from fossil fueled resources from out of state. However, a third scenario explores incremental investments needed to ensure 100% of the state's electric demand (on an annual basis) can be met with in-state carbon-free resources. Additional scenario exploration related to emissions targets is also possible in future cycles with the IPF built.

Introducing an Integrated Planning Framework

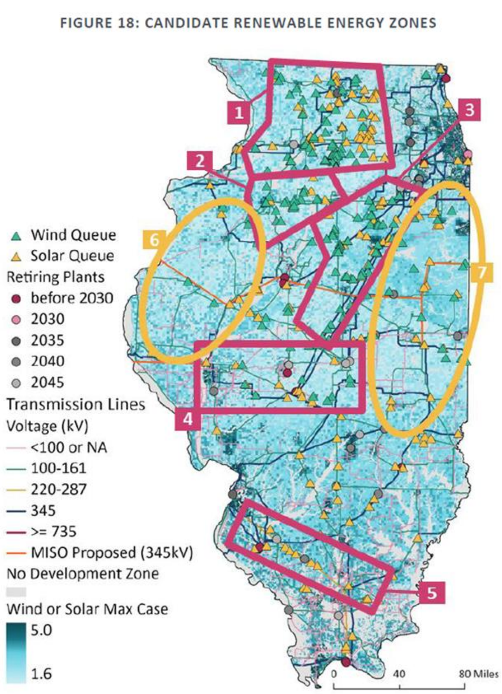
This REAP builds upon the foundation of the 2024 REAP by incorporating the renewable energy access zones into an IPF, which supports the identification of needs across both generation and transmission infrastructure to support the state's policy objectives.

Overview

The first REAP established seven REAP zones across the state shown in Figure 12 -

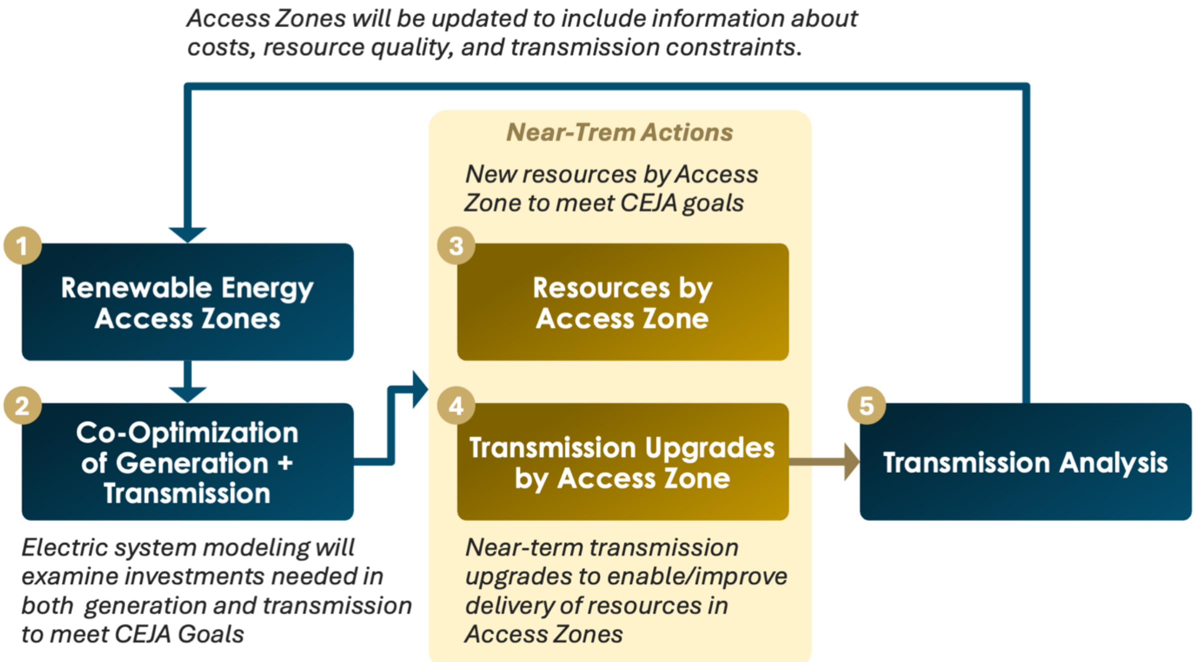
1. Level 1 zones (1-5) were defined as zones of "demonstrated interest" where there are many resources already in the Interconnection Queue. These areas are also likely to benefit from potential retirements of existing power plants, which may create headroom on the existing transmission network
2. Level 2 zones (6-7) were defined as areas with either (1) strong renewable potential but limited transmission or (2) significant transmission capability but limited ability to permit new renewables

Figure 12: REAP Zones Identified in the First REAP



Building on this foundation, the current REAP examines how Illinois can identify and pursue a cost-effective portfolio of generation and transmission infrastructure to achieve its clean energy goals. Because transmission projects have long lead times, proactive planning is essential to avoid delays, reduce costs, and maintain reliability. An IPF has been developed to coordinate generation and transmission planning, as illustrated in Figure 13.

Figure 13: Integrated Planning Framework



Proactive, integrated planning enables timely interconnection of new generation and reduces project-specific risks. It supports coordinated infrastructure investment, i.e. ensuring the grid is right-sized from the outset rather than expanded through incremental, costly upgrades. The IPF will evaluate generation and transmission options together, providing a consistent basis for identifying the most cost-effective portfolio of both for Illinois customers. Its outputs - resource additions by REAP zone and required transmission upgrades[76], will inform RTO and utility transmission planning processes. Given Illinois' participation in two RTOs, MISO and PJM, a shared data foundation is critical for coordinated interregional planning. Each REAP cycle will refine the REAP zones feeding into the IPF and the portfolio of investments resulting from it using latest available information on transmission headroom, upgrade costs, siting constraints, stakeholder feedback, RTO and utility studies, etc. Similarly, outputs from this framework can also feed into RTO and utility planning studies and inform ICC advocacy in regional planning processes, as will be discussed in Chapter 5.

The process, shown in Figure 13, will be iterative and data-driven; importantly, the modeling in this REAP cycle is intended to demonstrate the conceptual framework, and over future cycles the framework will be seeded with more accurate data to represent constraints and associated upgrade costs on the transmission system over time. The planning framework begins with identification/refinement of REAP zones (Step 1), which are

[76] *Transmission upgrades reported in this REAP are meant to be an indication of potential transmission bottlenecks and needs. These needs can be filled with transmission upgrades, greenfield transmission projects, non-wire alternatives or advanced transmission technologies, as will be discussed in Chapter 4.*

areas with renewable interests and potential. The IPF then co-optimizes generation and transmission (Step 2) to minimize cost, maintain reliability, and meet policy goals[77]. The resulting portfolios will identify near-term resource investments by REAP zone (Step 3) and targeted transmission upgrades needed to deliver these resources to load centers (Step 4). Multiple scenarios can be evaluated to determine "least-regret" investments. Resources selected in the longer term can then be mapped to substations with further analysis to identify emerging transmission constraints (Step 5). Insights from Step 5 then feed back into subsequent REAP cycles to refine REAP zones and planning assumptions.

Resource Adequacy Considerations

With significant load growth expected, especially from data centers, considering resource adequacy needs and taking steps to ensure resource adequacy is of prime importance today. The need to eliminate emissions from fossil fueled generators and electrify the economy to meet CEJA goals adds to the complexity. The Illinois Environmental Protection Act (415 ILCS 5/9.15) Section 9.15(o) requires the Illinois Environmental Protection Agency (EPA), the Illinois Power Agency (IPA), and ICC, to jointly conduct a Resource Adequacy Study (RA Study) with the initial report due December 15, 2025, and subsequent reports due every 5 years thereafter. Detailed consideration of resource adequacy is to be found in the RA Study. However, given the inter-related nature of resource adequacy with long term renewable energy access and transmission planning, this REAP uses the same core assumptions and modeling framework as the RA Study. Long term resource portfolios and potential transmission needs are identified to both meet CEJA and maintain adequacy.

Step 2 in the IPF relies on two key models, both of which are also used in the RA Study:

1. **Capacity Expansion with PLEXOS:** in this framework, PLEXOS LT[78] is used to optimize generation and transmission portfolios to minimize cost while satisfying policy and adequacy constraints.
2. **Resource Adequacy with RECAP:** RECAP identifies total effective capacity needed for resource adequacy and evaluates each resource's contribution towards meeting that need through extensive simulations of load and weather conditions.[79] In this report, it may also be referred to as a loss-of-load-probability (LOLP) model given these simulations yield the probability of total generation including storage dispatch falling short of need (which is called a loss of load event).

Figure 14 illustrates the interaction between these models. RECAP calculates Effective Load Carrying Capability (ELCC) for each resource type at different penetration levels to output an ELCC "curve". (This concept is described further in Appendix A. These curves then feed into PLEXOS to ensure that selected resource portfolios meet resource adequacy standards. Resource portfolios from PLEXOS then feed back into RECAP where they are stress tested under many weather years to confirm resource adequacy. Together, these models ensure portfolios are cost-optimal, reliable, and compliant with policy constraints. The same models and assumptions were also used in the RA Study, ensuring analytical consistency between the two studies.

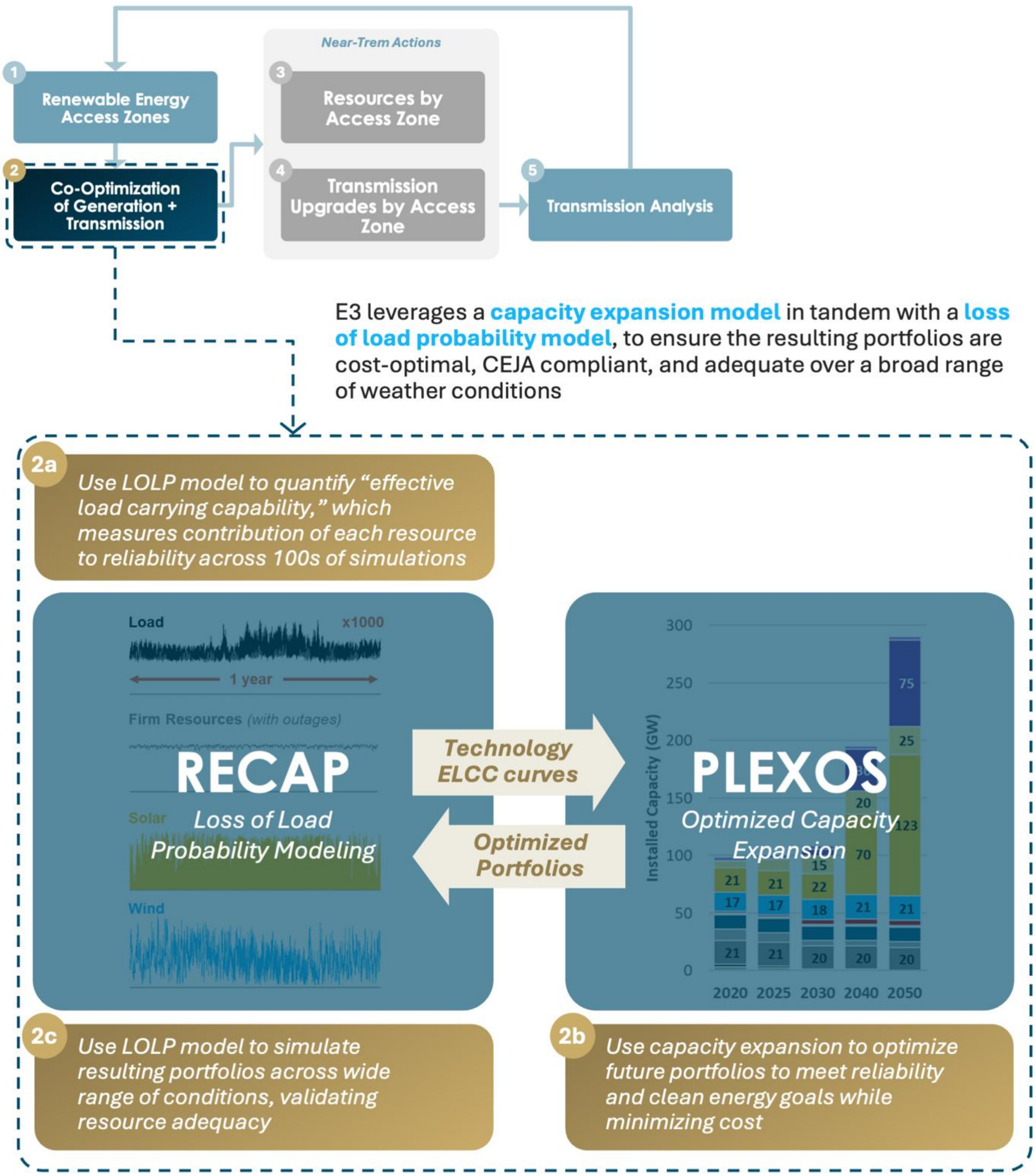
---

[77] Generation in Illinois is restructured, and the state is also part of two competitive electricity markets. The intention of this modeling and the REAP is NOT to dictate resource or transmission builds anywhere, but to rather understand long term infrastructure needs under multiple scenarios and inform state advocacy in regional planning processes.

[78] PLEXOS Long-Term (LT) is a commercially available capacity expansion modeling software licensed by Energy Exemplar; it is used by utilities and system operators across North America, and is the model currently used by MISO and PJM. For more information, see: https://www.energyexemplar.com/plexos.

[79] RECAP is E3's in-house loss-of-load probability (LOLP) model; it has been used by utilities and system operators across North America. For more information, see: https://www.ethree.com/tools/recap-renewable-energy-capacity-planning-model/.

Figure 14: Electric System Modeling Approach with Resource Adequacy Considerations



Ultimately, the IPF will help identify resource and transmission needs in the right locations, at the right times for Illinois to achieve CEJA goals cost-optimally, while maintaining local and RTO wide reliability. Identified needs can then inform state investments and advocacy in RTOs to fulfill those needs efficiently. The iterative nature of the IPF will account for constantly evolving system dynamics such as effects of electrification, data center growth, resource and transmission costs, etc.

Key Assumptions

Demand growth, system topology and candidate resources are some of the key assumptions that drive state-level builds and are presented in this section. Assumptions that impact REAP-zone-specific builds will be described in Chapter 3. Additional details related to resource costs, reliability parameters, etc. can be found Appendix A.

Electricity Demand Growth

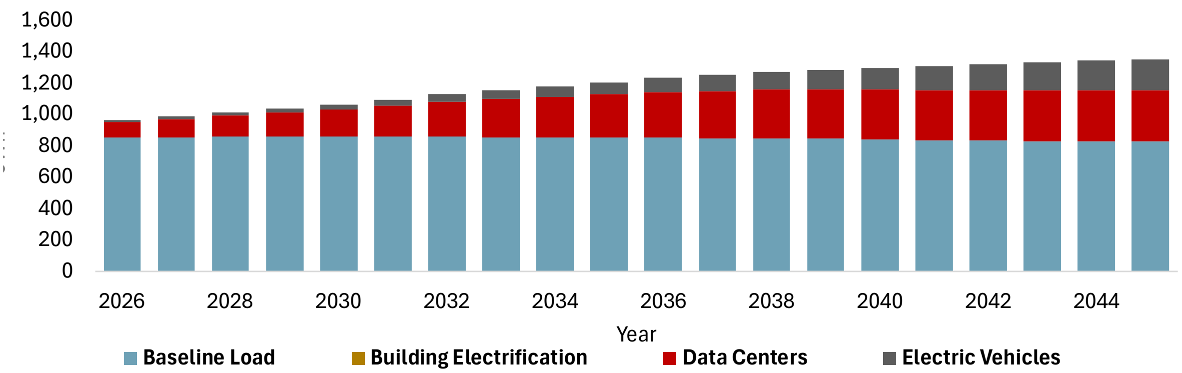
Data centers are the primary driver of load growth in current forecasts from utilities and the RTOs, as will be described in further detail below.

PJM

The load forecast for the PJM region was informed by the 2025 PJM Long-Term Load Forecast Report.[80] Data center forecasts were refined in the following ways – under construction and planned projects were reflected in the next six years. In 2032 and beyond, the year-on-year growth rate was assumed to gradually decay towards a more sustainable growth rate of 1% per year. With this approach, the data center load forecast in 2045 is 329 TWh compared to PJM's forecast of 525 TWh. This still represents substantial growth relative to today's levels. Data center load forecasting is extremely challenging. In the near-to-mid term, the risk of duplicative interconnection requests exists. Long term growth rates are also highly uncertain. PJM staff and stakeholders have proposed load forecasting enhancements as part of its Critical Issues Fast Path process.[81] PJM has not filed this with FERC at the time of writing this report. The PJM board previously indicated that they may be targeting a FERC filing in December 2025.[82] Each REAP cycle will be informed by the latest load forecasts from the RTOs.

Some EV load growth is also assumed in the longer term. In total, a 40% increase in load is forecasted between 2026 and 2045 as shown in Figure 15.

Figure 15: PJM Annual Load Forecast (TWh)



---

[80] PJM Long-Term Load Forecast Report (2025): https://www.pjm.com/-/media/DotCom/library/reports-notices/load-forecast/2025-load-report.pdf

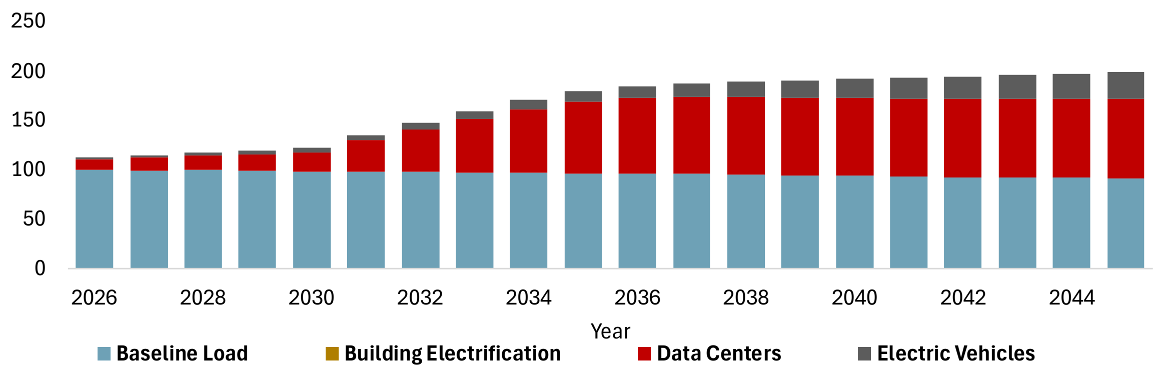
[81] PJM Large Load Additions CIFP Update (October 1, 2025): https://www.pjm.com/-/media/DotCom/committees-groups/cifp-lla/2025/20251001/20251001-item-04---cifp---lla-updates---pjm-presentation.pdf

[82] PJM message to stakeholders (August 8, 2025): https://www.pjm.com//-/media/DotCom/about-pjm/who-we-are/public-disclosures/2025/20250808-pjm-board-letter-re-implementation-of-critical-issue-fast-path-process-for-large-load-additions.pdf

ComEd Zone

ComEd utility's load forecast is consistent with that published in the State's 2026 LTRRPP.[83] Significant data center load growth is forecasted by ComEd. Since other entities such as municipal utilities and co-ops are also present within the PJM ComEd zone, the rest of the load in this zone were informed by the PJM forecast described above. The annual load forecast assumed for the ComEd zone is presented in Figure 16.

Figure 16: ComEd Zone Annual Load Forecast (TWh)



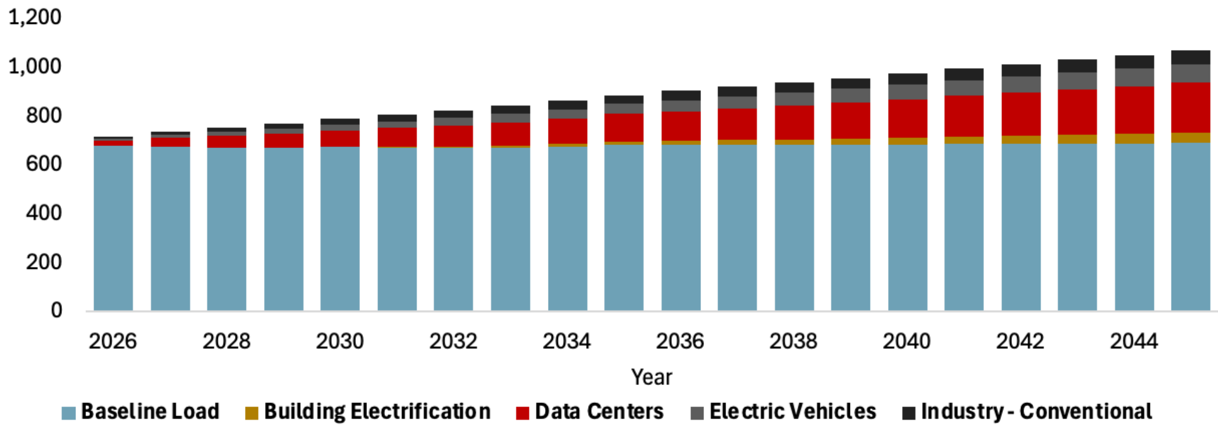
MISO

The forecast for the MISO region was adapted from the Current Trajectory Scenario in the Long-Term Load Forecast Report[84] published by MISO in December 2024. Since MISO already derated data center load forecasts, no additional derates were applied to the data center component of MISO's forecast. However, green hydrogen and IRA-boosted industrial load growth were excluded given federal policy headwinds. The MISO-wide annual load forecast is presented in Figure 17. MISO is forecasted to experience 50% load growth between 2026 and 2045. Much of this growth is expected from data centers, which grow from 3% of the total load in 2026 to 19% of the total in 2045.

---

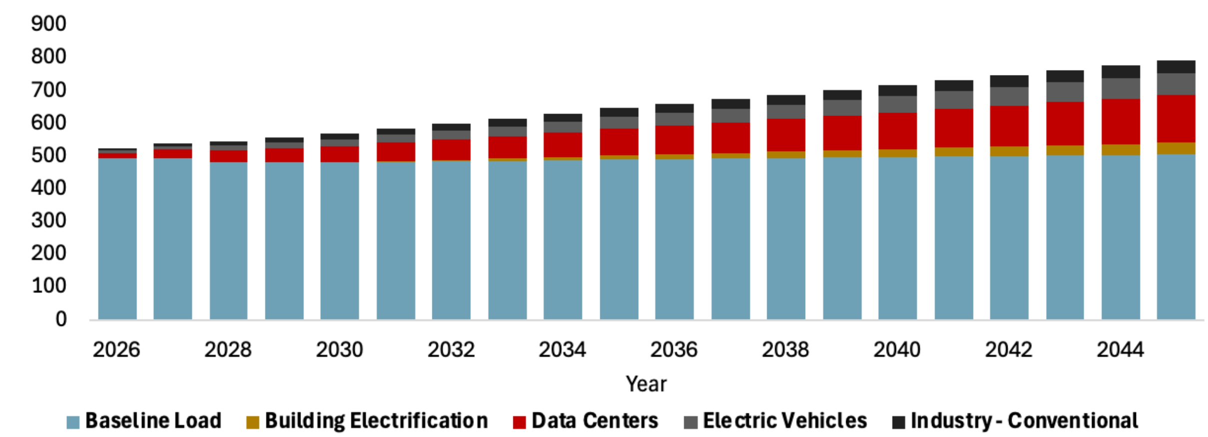
[83] *IPA Long-Term Renewable Resources Procurement Plan: https://ipa.illinois.gov/renewable-resources/long-term-plan.html.*
[84] *MISO Medium and Long-Term Load Forecast (December 18, 2024): https://www.misoenergy.org/events/2024/medium-and-long-term-load-forecast---december-18-2024*

Figure 17: MISO Annual Load Forecast (TWh)



The primary focus in this modeling exercise is on MISO LRZs 1-7 (henceforth MISO North) given transmission constraints between MISO North and South and thus relatively limited influence of the latter on Illinois. Figure 18 shows the MISO North annual load forecast. MISO North represents between 70-75% of total MISO load. Load in MISO North is projected to grow 52% between 2026 and 2045 with datacenters driving much of that growth.

Figure 18: MISO North Annual Load Forecast (TWh)

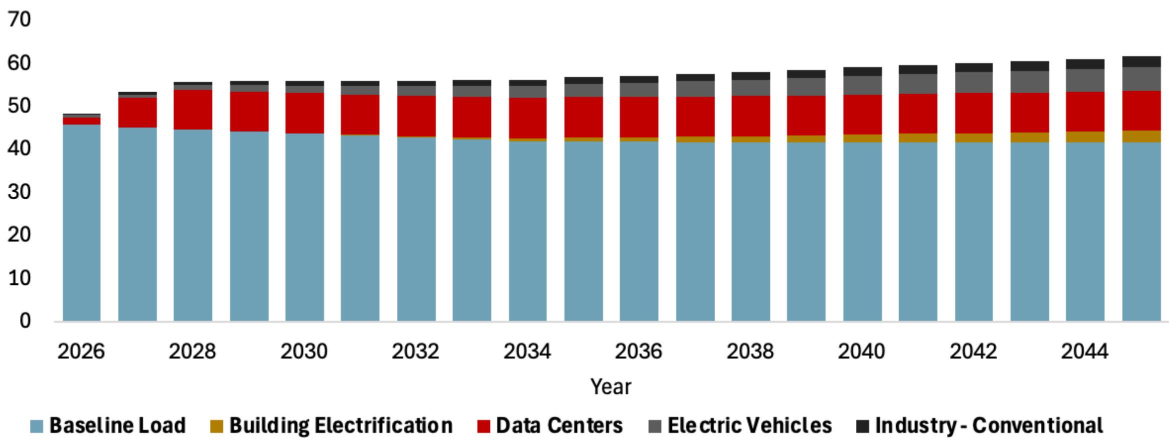


Local Resource Zone 4

Ameren Illinois is located within MISO Local Resource Zone (LRZ) 4. Ameren Illinois's assumed load forecast is consistent with the 2026 LTRRPP.[85] Ameren Illinois forecasts significant data center load growth in the near term. The rest of LRZ 4 loads are informed by MISO's long-term forecast described above. The annual load forecast for LRZ 4 is shown in Figure 19.

[85] *2026 Long Term Renewable Resource Procurement Plan: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20251020-2026-long-term-renewable-resources-procurement-plan.pdf*

Figure 19: LRZ 4 Annual Load Forecast (TWh)

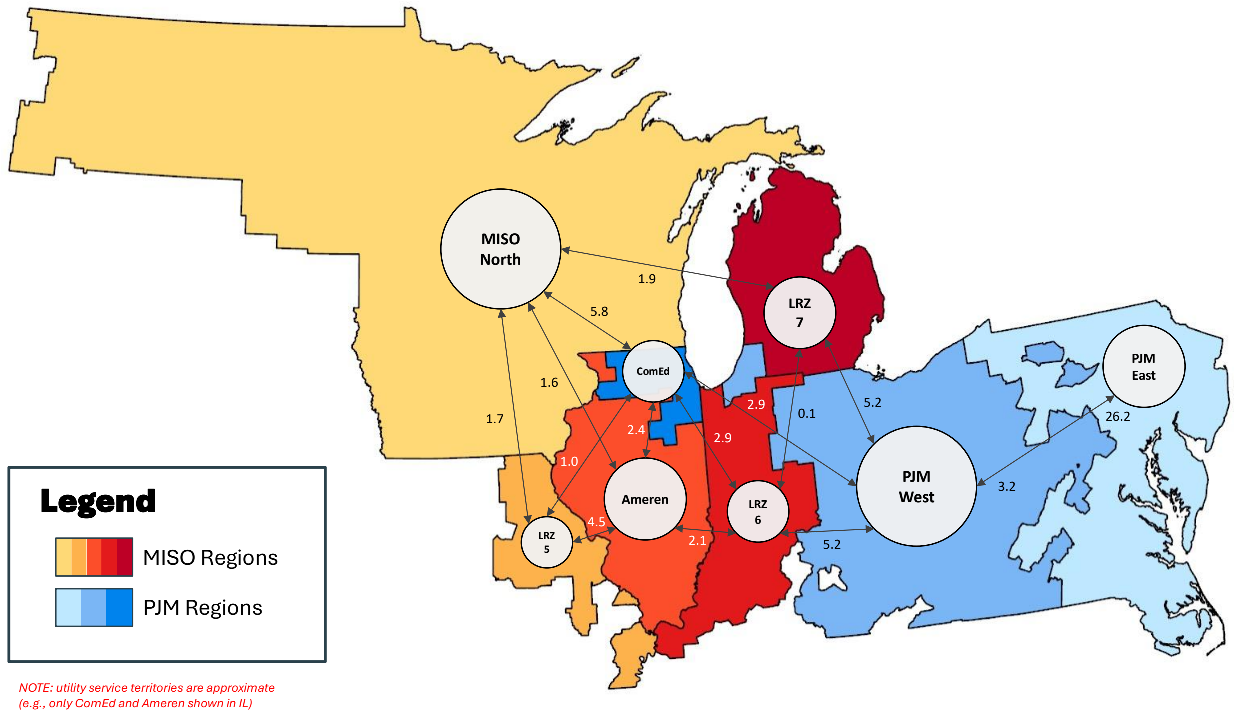


System Topology

The interconnected power system was modeled with a zonal "pipe-and-bubble" representation, as shown in Figure 20. Each bubble contains load and resources corresponding to the zone and the pipes represent max hourly transmission flow in Gigawatt (GW) allowed in each direction between two zones. Transmission line limits are informed by U.S. Energy Information Agency (EIA) hourly electric grid monitor[86], MISO 2024 LOLE Study Reports[87], MISO Transmission Expansion Plan (MTEP) 2024[88], PJM Regional Transmission Expansion Plan (RTEP) 2024[89] and MISO's Tranche 1 and 2.1 reports under its Long Range Transmission Planning process.[90] The modeled footprint includes both MISO and PJM regions to capture broader system reliability needs and interactions between Illinois zones and the markets. Within Illinois, the PJM ComEd and MISO LRZ 4 zones are represented as distinct zones, each with its own local reliability need. Figure 20 does not show MidAmerican Energy and Illinois municipal and cooperative utilities for simplicity. Their loads and resources are aggregated within the larger zones that they are a part of. This zonal representation enables the model to simulate transmission-limited power exchanges while maintaining computational tractability for long-term capacity expansion modeling. The two Illinois zones are further downscaled into REAP zones to more accurately characterize local resource potential, quality and transmission network characteristics. These will be described in further detail in Chapter 3.

[86] *EIA Grid Monitor: https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48*
[87] *MISO 2024 LOLE Study Report: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf*
[88] *MISO MTEP24: https://cdn.misoenergy.org/20241001%20PAC%20Item%2002%20MTEP24%20Report%20Preview650567.pdf*
[89] *PJM Reliability Analysis Report RTEP 2024: https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2025/20250304/20250304-2024-rtep-window-1-reliability-analysis-report.pdf*
[90] *MISO (Long Range Transmission Planning) LTRP projects: https://www.misoenergy.org/planning/long-range-transmission-planning/*

Figure 20: PJM & MISO Transmission Topology in 2030



Candidate Resources

Candidate resources represent options that were made available to the model to be added on top of the existing resource portfolio to meet Illinois' future needs. In-state candidate resources include: utility scale and distributed solar, onshore wind, gas combustion turbines (CT) and combined cycle (CC) turbines (which were required to be hydrogen-ready (H_2-ready) and capable of running 100% hydrogen by 2045 to be compliant with CEJA), 4-hr Li-Ion battery storage[91] and nuclear. Additionally, capacity purchases from the rest of the RTOs were also allowed in some scenarios. These purchases were priced at the cost of building a new gas CT in neighboring states and the total purchases were limited by the Capacity Emergency Transfer Limit (CETL) for ComEd and the Zonal Import Ability (ZIA) for LRZ 4. Details on CETL and ZIA assumed can be found in the appendix.

Non-powered dams converted to produce hydropower are also RPS eligible, and the REAP is directed to study the impact of these resources relative to alternative RPS-eligible resources. However, to date, the IPA's Indexed REC procurement events have not yielded RECs from this resource type. In its draft 2026 Long Term Renewable Resource Procurement Plan (LTRRPP), the IPA requested stakeholder feedback on how to ensure these facilities participate in the IPA's competitive procurements and if RECs from these facilities should be procured through a different approach. No feedback was received.[92] As a result, this REAP does not study this resource type. If these resources participate in future procurement processes and data on site-specific potential and costs within Illinois emerge, then they can be studied in future REAP cycles.

---

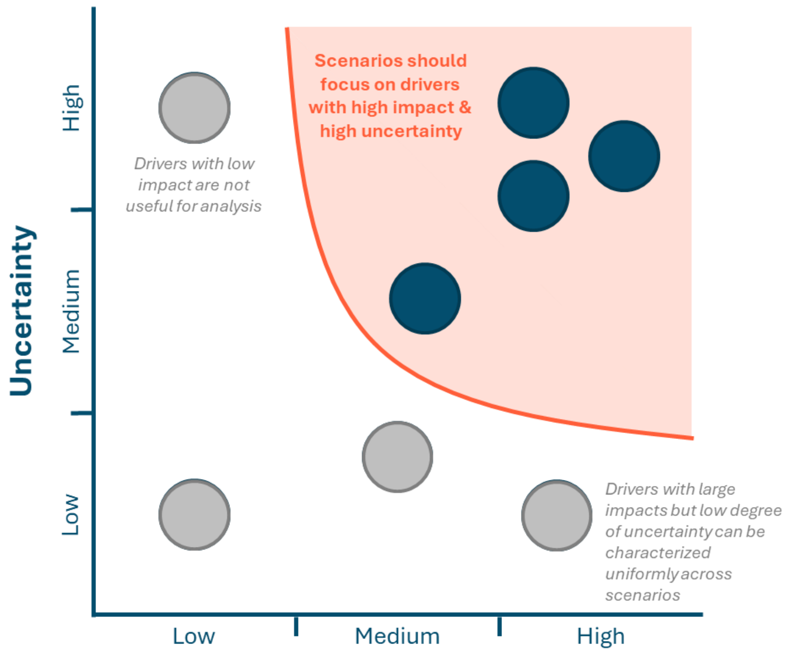
[91] Longer durations storage can be studied in future REAP cycles.
[92] For more information related to hydropower, see Section 5.5.4 in the final 2026 LTRRPP - https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20251020-2026-long-term-renewable-resources-procurement-plan.pdf.

Scenario Design

Transmission is a long lead-time asset. Proactive planning is key to ensure transmission needs and solutions to fill those needs can be identified and developed in a timely manner to maintain reliability and meet CEJA goals. However, when planning the system over a 20-year horizon or more, there is significant uncertainty related to demand, supply, and policy - all of which will impact the optimal mix of transmission and resource investments required. Studying multiple scenarios is key to ensure "least-regret" investments can be identified that fulfill the system's needs economically over a broad range of possibilities.

Scenarios should be designed to study the impact of external factors that both have a high impact and a high level of uncertainty, as illustrated in Figure 21.

Figure 21: Illustrative Classification of Factors Informing Scenario Design by Impact and Certainty



A public workshop was conducted in August 2025 on scenario design. Multiple high impact-high uncertainty factors were presented to stakeholders as shown in Table 4. Stakeholder feedback was sought after the workshop to identify the most important factors that will continue to be studied beyond the publication of this REAP update. Stakeholders agreed with the importance of these factors presented and also proposed additional factors for consideration including load flexibility, siting, permitting and property tax reforms impacting project development, interregional transmission expansion and changes to import capability.[93]

[93] *Not an exhaustive list. Factors that meaningfully overlapped with those originally proposed in the workshop have not been repeated.*

Table 4: High Impact - High Uncertainty Policy and Infrastructure Factors That Can Inform Future Analysis

Scenario Dimension	Factors	Range/Causes of Uncertainty
Policy	Electrification	Low/no electrification due to slow customer adoption and lack of policy support to high electrification consistent with economy-wide decarbonization goals
	Renewable & Storage Targets	Limited procurement driven by high resource costs and other factors to procurement consistent with long term decarbonization goals
	Carbon Policy	Retirement schedule for existing fossil, role of new in-state combustion-based resources, and imports from rest of RTOs in the long term**
Infrastructure	Data Center & Industrial Load Growth	Pace and scale of load growth are uncertain and driven by multiple macro-economic and socio-political factors
	Supply Chain, Siting, Permitting, and Development	These factors influence the pace and scale at which resources and transmission projects can be deployed and vary by resource type
	Storage, DERs and GETs	Limited potential will drive up need for transmission upgrades; higher potential can maximize utilization of existing transmission and limit incremental upgrades

**This table is meant to be illustrative and is not exhaustive in any respect*

***Modeling capability is demonstrated with respect to these factors in this report. Additional factors and scenarios based on them will continue to be studied in the future.*

Building the IPF including the models for coordinated generation and transmission optimization (shown in Figure 14) was prioritized for this REAP update. This foundation can be leveraged to study multiple scenarios in the future.

Three scenarios are highlighted in this REAP to demonstrate the coordinated generation and transmission optimization. These scenarios are described in Table 5. All scenarios reflect the CEJA legislative requirements of 50% RPS and fossil fuel phase out. The key distinguishing factor between these scenarios is the role of in-state combustion resources and imports in maintaining reliability. This factor was studied given it can significantly influence the level and type of clean resource and transmission builds in-state that may be necessary in the long term. Other factors of high importance will continue to be studied in future REAPs informed by stakeholder feedback described above.

Table 5: Scenarios Studied for This REAP Update

	H_2-Ready Combustion Allowed	No New Combustion Capacity	No Net Imports
Key Differences			
New In-State Combustion Capacity	+ New combustion turbines allowed in IL; need to be H_2-ready 2045	+ No new combustion capacity in IL	+ New combustion turbines allowed in IL; need to be H_2-ready and burn 100% H_2 by 2045
Imports	+ No restrictions on imports for energy or capacity, even if they come from out-of-state fossil	+ No restrictions on imports for energy or capacity, even if they come from out-of-state fossil	+ IL's capacity requirement for reliability must be fully met with in-state clean capacity by 2045 + IL must export at least as much clean energy as it imports to offset emissions caused by imports and be 100% clean on an annual basis by 2045
Common Assumptions			
Load Forecast	+ Consistent with assumptions presented in this chapter		
Renewables	+ 50% RPS by 2040 + Economic builds beyond target are always allowed		
Existing Fossil Generation	+ CEJA retirements in IL occur on schedule		

Findings

This section will describe key state-level findings. REAP-zone specific results will follow in Chapter 3.

Substantial growth in in-state renewable energy is needed to meet the 50% RPS by 2040. This renewable energy, combined with existing nuclear, may help meet 95%+ of the state's annual energy needs: Given current load forecasts, Illinois' total solar and wind nameplate capacity is projected to grow to up to 57 GW by 2040 to meet these targets. Combined with generation from existing nuclear units, 95%+ of the state's energy needs can be matched with clean generation in 2040-2045 on an annual basis. The remaining energy may come from imports or incremental clean generation in-state based on scenario. As described above, the load forecasts currently do not assume aggressive electrification that may be required to pursue the economy-wide emissions goals set forth in CEJA. With increased electrification, resource needs would increase further.

Battery storage and new firm capacity both have a role to play in supporting balancing needs and maintaining reliability: Given the intermittency of renewable generation, the system will need resources that can balance supply and demand over different timescales. Short-duration battery storage and flexible demand help manage hourly fluctuations by shifting energy from times of excess to times of need. However, when renewable generation remains low for multiple days, longer-duration storage, clean firm clean resources such as H_2-ready gas turbines, advanced nuclear, etc. can help maintain reliability. Three GWs of 4-hr storage is built within all scenarios modeled to support intra-day balancing. When in-state combustion is limited, additional clean firm and storage resources are selected by the model to maintain reliability. Imposing restrictions on certain resource options can drive the need to "overbuild" other resource options. This may also drive the need for additional transmission upgrades, as will be illustrated in Chapter 3.

Optimal State-wide Nameplate Capacity and Annual Energy Balance Across Modeled Scenarios

New H_2-Ready Combustion Capacity Allowed

Figure 22: Total Nameplate Capacity (Left) and Annual Energy Balance (Right) for Illinois When New H_2-Ready Combustion Capacity is Allowed

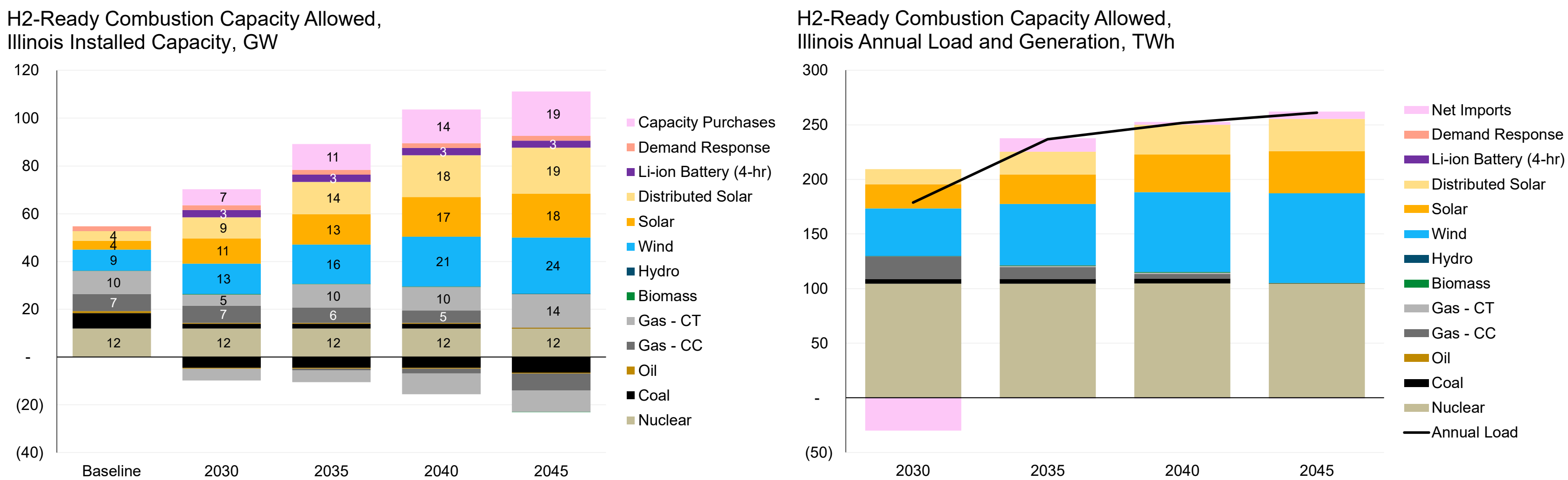


Figure 22 shows the state-wide installed capacity and energy balance evolution through 2045 when H_2-ready combustion capacity is allowed. In this scenario, Illinois sees significant renewable expansion to meet the 50% RPS alongside additions of firm resources to ensure reliability standards continue to be met with growing load and despite retirements. Installed nameplate capacity approximately doubles relative to today's levels. A 61 GW renewable portfolio meets RPS requirements. Three GWs of 4-hr battery storage are selected for intra-day balancing. To maintain resource adequacy in longer periods of need, 14 GWs of new H_2-ready gas CTs are selected, complemented by 19 GWs of capacity purchases from neighboring regions by 2045. While H_2-ready CT capacity increases over time, utilization decreases as renewable generation satisfies a growing share of energy needs. By 2045, renewable and nuclear generation supply roughly 97% of annual electricity needs statewide. Imports fill the remaining gap given their lower cost compared to in-state gas or hydrogen CT generation.

New In-State Combustion Capacity Not Allowed

Figure 23: Total Nameplate Capacity (Left) and Annual Energy Balance (Right) for Illinois When New In-State Combustion Capacity is Not Allowed

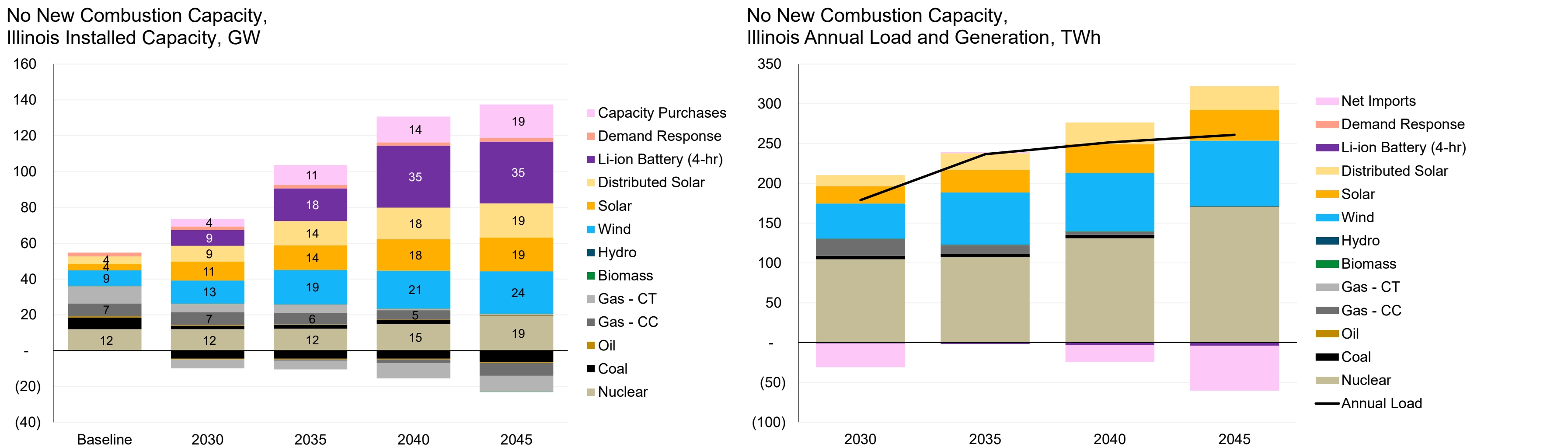


Figure 23 shows the state-wide installed capacity and energy balance evolution through 2045 when new combustion capacity is not allowed. In this scenario, expanded deployment of storage and nuclear in-state is selected for reliability. Compared to the H_2-ready combustion scenario, 32 GWs of incremental 4-hr storage, 1 GWs of incremental solar, and 7 GWs of new nuclear capacity are selected. In sum, 40 GWs of incremental resource capacity is selected, which provides the same reliability value as 14 GWs of H_2-ready CTs. The significant "overbuild" of 4-hr storage is reflective of its diminishing value of 4-hr storage towards meeting longer duration needs. With longer durations, lower storage capacity would be required to provide equivalent reliability value. Nuclear has a very high upfront capital expenditure but relatively low operational expenditure and is thus highly utilized when selected. Thus, with the significantly expanded nuclear fleet, Illinois remains a net exporter of electricity in the long term in this scenario. This reflects the tradeoffs associated with restricting the buildout of new combustion-based resources in-state.

Net Imports Not Allowed by 2045

Figure 24: Total Nameplate Capacity (Left) and Annual Energy Balance (Right) for Illinois When Net Imports Are Not Allowed by 2045

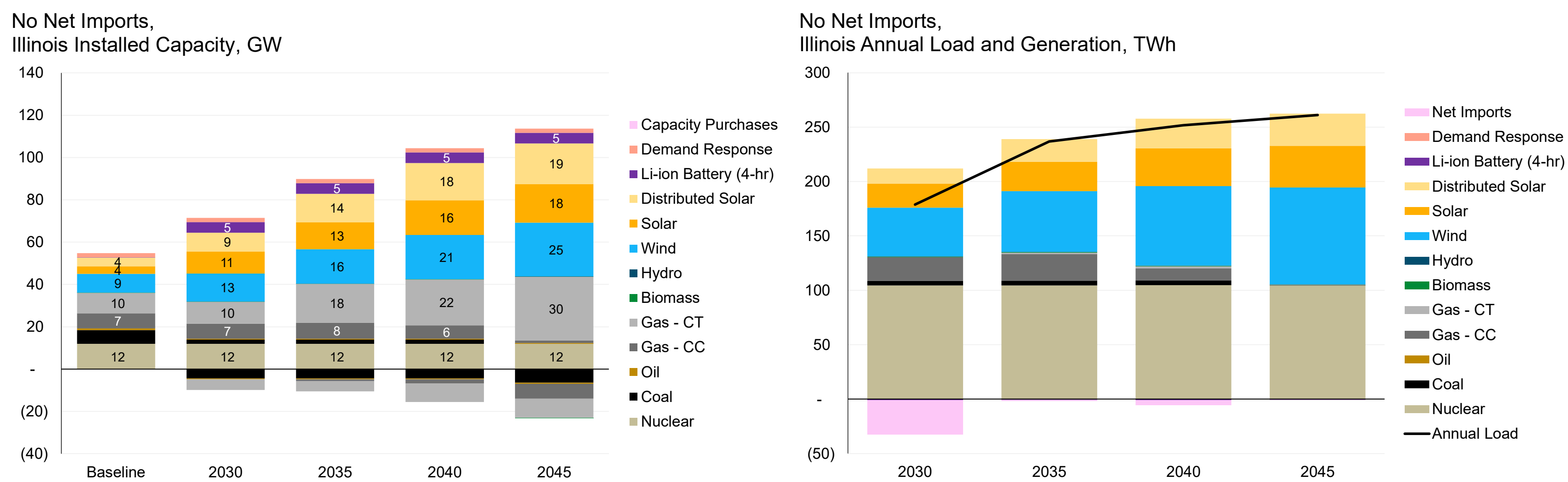


Figure 24 shows the state-wide installed capacity and energy balance evolution through 2045 when capacity purchases from the rest of the RTOs and net imports of energy on an annual basis are not allowed by 2045. In comparison to the scenario where these restrictions on out-of-state resources do not exist (see Figure 22), 19 GWs of capacity purchases are replaced with 17 GW of incremental in-state H_2 CT/CC capacity and 2 GW of incremental storage. 1 GW of wind is also added to ensure that Illinois remains self-sufficient on an annual energy basis. 100% of Illinois’ electricity requirement is matched with generation from in-state carbon-free resources on an annual basis in this scenario and emissions from net imports on an annual basis is zero. However, this requires incremental in-state resource capacity and transmission upgrades (the latter of which will be described in Chapter 3). This reflects the trade-offs of limiting reliance on out-of-state resources.

Recommendations

The major accomplishments of this REAP include designing an IPF to identify the generation and transmission needs to achieve the state's policy targets. Three scenarios were developed to demonstrate the capability to model the two-RTO electric system that Illinois is a part of. These models are the "engine" of this planning framework. Future REAP cycles can continue to build on this foundation in the following ways.

Additional Scenario Analysis

Future REAP cycles should consider additional scenarios informed by the stakeholder input gathered during the August 2025 scenario design workshop and in future workshops. The workshop identified key high-impact, high-uncertainty factors presented in Table 4, and stakeholders proposed several more, including load flexibility, siting and permitting, property tax reforms, interregional transmission expansion, and import capability changes.

Studying additional scenarios will help the State understand the tradeoffs between different CEJA compliance pathways under evolving reliability and affordability conditions, while supporting low-regret decision-making. Balanced with practical constraints on the number of uncertainties that can be feasibly studied, future REAP scenario design should be guided by stakeholder feedback, alongside emerging developments in the state, regional electricity markets, and other influencing factors.

For example, a scenario incorporating incremental load growth driven by electrification can help evaluate the investments required to meet both electric-sector and economy-wide decarbonization goals. Similarly, studying a scenario with interregional transmission expansion would align with the State's ongoing efforts to strengthen coordination between MISO and PJM, building on recent initiatives such as the RTOs' Interregional Transfer Capacity Study (ITCS) (discussed in further detail in Chapter 5). These scenarios, grounded in stakeholder priorities, will ensure that future REAP analyses remain responsive to real-world uncertainties and effectively inform the state's strategic path towards a decarbonized electricity mix.

Strengthen Regional Alignment with Data Sharing

REAP modeling assumptions should be regularly reconciled with latest planning efforts at the utility and RTOs levels. This will ensure the REAP analysis and its outputs remain credible and directly usable in regional planning processes to be discussed in detail in Chapter 5.

Further Consideration of Non-Wires Alternatives and Advanced Transmission Technologies

A limited subset of non-wires alternatives (e.g. distributed solar) was modeled directly in the analysis presented in this REAP. Exploration of how to incorporate additional NWAs and ATTs into the integrated planning framework should continue in future REAPs, as will be discussed in more detail in Chapter 4.

Demonstrate Remaining Steps in the Integrated Planning Framework

The goal in this REAP cycle was to demonstrate the ability to model REAP zones (to be discussed in further detail in Chapter 3) and demonstrate co-optimization of generation and transmission given it is the analytical engine of the IPF. The outputs of the IPF will then feed into two processes: (1) identification of near-term actions and (2) mapping of resource portfolios to the transmission system to examine transmission constraints likely to emerge in the long-term. With regard to near-term actions and investments, continued refinement of major assumptions is warranted to ensure that investments and next steps can be identified with high confidence.

Beyond that, developing the methodology to map long-term resource additions in select scenarios to substations, perform transmission analysis and support continued refinement of REAP zones to make them more actionable should take priority.

Strategic Element 3: Managing Land Use in Renewable Development

Strategic Element 3, *Managing Land Use in Renewable Development*, examines how Illinois can refine and operationalize REAP zones to support cost-effective, community-aligned renewable and transmission development. The chapter begins by describing updates since the 2024 REAP, including new statewide siting standards. The chapter then outlines the analytical enhancements undertaken this cycle starting with geocoding of REAP zones identified in the 2024 REAP and continued data development to estimate land suitability and resource potential within each zone. It then explains how these refined zones are implemented in the capacity expansion model in the IPF, including representations of local transmission headroom, headroom utilization by resource type, and upgrades within each REAP zone. The chapter concludes by assessing preliminary findings on renewable potential, transmission headroom created by fossil retirements, and the mix of generation and transmission builds selected across scenarios, followed by recommendations for future refinement, expanded land-use analysis, and deeper engagement with relevant agencies and communities. Collectively, these sections establish how land-use considerations, infrastructure siting opportunities and constraints can continue to be studied in the REAP.

Highlights from the 2024 REAP

The 2024 REAP identified candidate renewable energy zones, or "REAP zones," which CEJA defined as regions where "suitable land areas are sufficient for developing generating capacity from renewable energy resources."[94] The main criteria used to delineate these zones were the amount of headroom expected to be created by retiring fossil fuel generators in the near term as well as the ability to build new transmission assets where renewable potential exists in the long term. Resource potential, proximity to retiring generators, developer interest, current land uses and crop productivity, protection of endangered species and critical natural habitats, and equity and environmental justice considerations were also considered as part of the process.

Evolving REAP Zones in 2025 Draft REAP

The first iteration of REAP zones served as a foundation upon which to develop a more refined understanding of where renewable resource development might occur within Illinois. In the 2024 REAP, the zone boundaries lacked specificity, which complicated efforts to incorporate granular resource potential and cost data during modeling. As part of this cycle, the ICC is developing a framework to identify "least-regret" investments in the REAP zones that maintain reliability and meet CEJA goals at least cost, which demands a more detailed definition.

Building on the REAP zones approved in 2024, this 2025 Draft REAP has prioritized the following tasks:

1. Geocoding of the REAP zones informed by the transmission system so each zone has specific boundaries. This enables estimation of the resource potential within each zone and facilitates further screening in the future to make the zones more "actionable."

[94] *Illinois Climate and Equitable Jobs Act, Pub. Act No. 102-0662, S.B. 2408, 102nd General Assembly (Ill. 2021).*

2. Building a modeling framework that co-optimizes generation and transmission builds within each REAP zone across scenarios and identifies needs that can feed into regional planning processes.
3. Continued collection of datasets to estimate the suitability of land for renewable and/or transmission development; this includes coordination with the Illinois Department of Natural Resources (IDNR) to identify datasets that could inform resource siting in or near areas of natural, cultural, and historical importance.

Over time, the costs and resource potential of renewables in each REAP zone will be further refined based on available information regarding region-specific development and other land use considerations within Illinois.

Land-Use Related Policy Development Since the 2024 REAP

Shortly before the publication of the previous REAP, the Illinois legislature passed Public Act 102-1123, which prohibits counties from imposing blanket bans on commercial solar and wind energy facilities as well as establishing state-wide siting and zoning standards.[95] A review by ICC Staff found that prior to the passage of this Act, siting processes and zoning ordinances varied dramatically across the state, sometimes within the same county. Now, counties are barred from adopting zoning practices more restrictive than those laid out in the Illinois Counties Code, 55 ILCS 5/5-12020. This includes minimum setbacks for commercial solar and wind facilities, height restrictions, sound limitations, zoning regulations, permit application fees, and more. [96]

Although the Act does not deal directly with transmission infrastructure, there is a provision that prevents counties from establishing siting standards for transmission lines, substations, access roads, and other equipment associated with the generation or storage of electricity that preclude development of a commercial solar or wind facility.[97] Siting of standalone transmission projects is handled via ICC's Certificate of Public Convenience and Necessity (CPCN) process, which sets forth certain requirements for the utility to engage with local authorities and establishes a construction fee per mile of high-voltage line that utilities must pay in lieu of individual permitting fees imposed by counties. Counties and municipalities do retain some control over land use and zoning ordinances, but their ability to oppose the siting of a new transmission line altogether is limited.

Analytical Updates Related to REAP Zones

During this cycle, the REAP zones identified in 2024 were geocoded with slight adjustments to more accurately reflect network topology. The state was also able to secure technical assistance from the U.S. Department of Energy's (DOE) Pacific Northwest National Laboratory (PNNL) to begin collecting more granular data on the suitability of regions within each REAP zone for renewable development. Lastly, the capability to directly model REAP zones in PLEXOS was developed, facilitating the co-optimization of generation and transmission investments. Details follow in the rest of this section.

---

[95] *Illinois General Assembly, Public Act 102-1123: https://www.ilga.gov/documents/legislation/publicacts/102/PDF/102-1123.pdf*
[96] *Illinois Counties Code, 55 ILCS 5/5-12020: https://www.ilga.gov/Documents/legislation/ilcs/documents/005500050K5-12020.htm*
[97] *Ibid.*

Geocoding and Continued Data Development

To facilitate future refinement of REAP zones, the initial rudimentary REAP zones in the previous REAP (see

Figure 12) were converted to a shapefile using ArcGIS. In doing so, several minor adjustments to the borders of each zone were made based on network topology (i.e., the location of high-voltage lines and substations), the goal being to avoid arbitrarily dividing portions of the grid that are highly interconnected (see Figure 25). This process will simplify future efforts to further refine REAP zones and to map resources selected during capacity expansion to a specific substation, a key step in the IPF (see Step 5 in Figure 13).

REAP zones 1-7 are maintained for consistency with the previous REAP, with boundaries now refined. Additionally, the rest of the state is also included in the analysis, shown as named zones in Figure 26 -Greater Chicago, ComEd South, Greater Peoria and Southern IL. These named zones were added to cover the entire state for the following reasons –

1. There is at least some renewable potential in every part of the state
2. Even if siting restrictions limit renewable development in some of these zones, such as Greater Chicago, fossil retirements in these zones will create transmission headroom that can be utilized to integrate other types of resources
3. The IPF has been developed to model the power system across the entire state and identify resource and transmission needs to maintain reliability and meet policy targets. Given the interconnected nature of the power system, it is not appropriate to exclude parts of the state.

Thus, moving forward, the entirety of the state will be studied in the REAP, although REAP zone boundaries and renewable potential within them may continue to be refined.

Figure 25: Previous Cycle REAP Zones

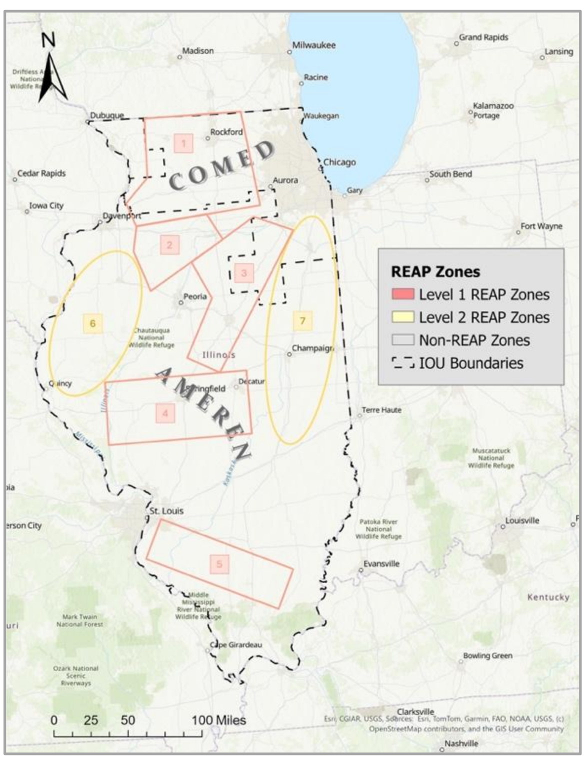
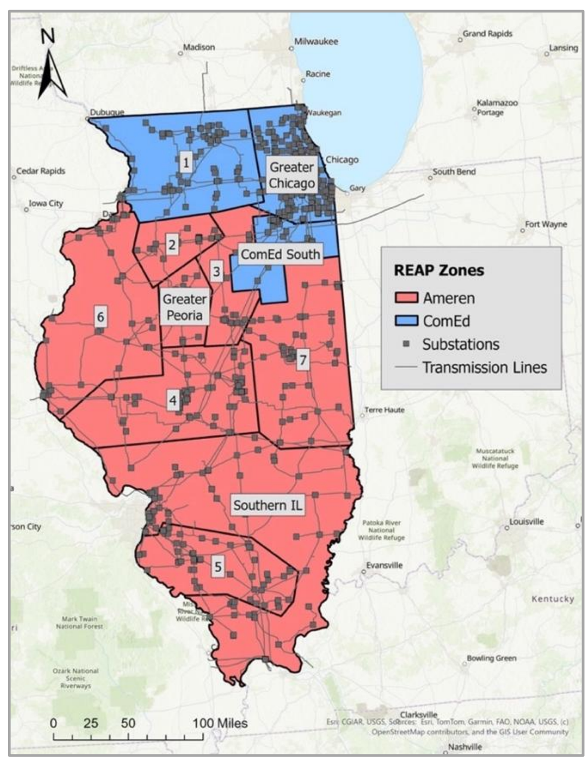


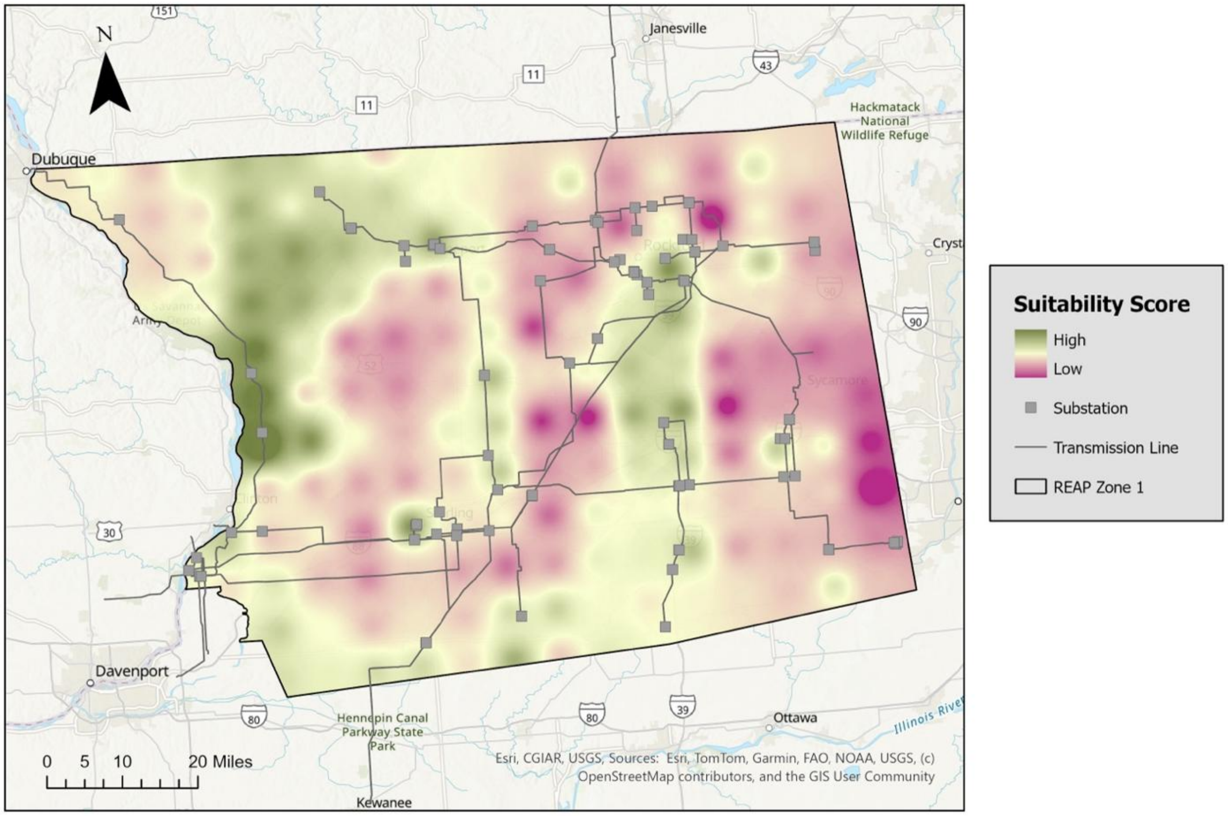
Figure 26: Latest Geocoded REAP Zones



Separating Illinois into ComEd and Ameren (LRZ 4) is a visual simplification. In addition to parts of the state falling within MISO LRZs 1 and 3, several municipal utilities and co-ops are spread throughout. While not shown in the figure above, the loads and resource potentials associated with these regions are accounted for in the electric sector modeling.

In response to Section III.C.3 of the 2024 REAP report, ICC enlisted the help of PNNL to collect data and develop preliminary weighted "suitability" scores to be used in future REAP zone refinements or the allocation of selected resources to substations within a REAP zone. The original REAP zones were loosely informed by a similar methodology used by SEDAC in its 2021 Solar Suitability Study, which included criteria for solar and wind potential, crop productivity, and proximity to equity zones. PNNL's approach captures a much wider range of factors related to grid infrastructure, land use, environmental impact, and socioeconomics. The individual data layers are then combined using appropriate weights to form a single score that reflects the suitability of each cell in a 10 km x 10 km grid for renewable development. Figure 27 is an illustrative example of the type of insights such an analysis might be able to provide, once the criteria and weights have been finalized.

Figure 27: Illustrative Suitability Analysis of REAP Zone 1



In the above map, the region to the north of Fulton is identified as potentially suitable for renewable integration due to a combination of factors, including relatively high wind resource quality, low population density, and proximity to transmission infrastructure. Note that this map is for illustrative purposes only and the results should not be considered final at this stage.

As part of this REAP update, ICC also reached out to IDNR to identify data sources that could contribute to PNNL's efforts. Members of the Impact Assessment Unit pointed out several potential sources for future exploration, including the Illinois Natural Heritage Database, the Historical and Architectural Resources Geographic Information System (HARGIS), and the Prairie State Conservation Coalition's I-View database of protected lands. Data from the Illinois Natural Heritage Database can be incorporated into a suitability analysis illustrated above. The HARGIS data is currently considered incomplete but can be included once updated. PNNL has to date relied on the U.S. Geologic Survey's Protected Areas Database of the United States, or PAD-US, but further exploration of I-View may be warranted in future cycles.

ICC Staff and its consultants will continue to refine the methodology and data used to produce the suitability scores, with a two-pronged goal. The first is to make the REAP zones more actionable by clearly identifying regions suited to renewable development based on widely agreed-up factors. The second is to leverage more granular geospatial data to inform allocation of resources selected within a REAP zone during capacity expansion to specific substations. The location of these resources will be incorporated into estimates of transmission headroom in future cycles, further refining how the system is represented in PLEXOS (see Step 5 in Figure 13).

Implementation of REAP Zones in PLEXOS

Generator Representation

Once the REAP zones had been geocoded, high-resolution supply curve data for solar and wind were layered on from the U.S. DOE's National Renewable Energy Laboratory (NREL). These layers include detailed estimates of renewable energy potential at 4-km x 4-km resolution for solar and 2-km x 2-km resolution for wind, based on resource quality (i.e., solar irradiance or wind speed), technology design, siting constraints, and transmission costs. The potential of each resource within a grid cell is split into tiers based on capacity factor[98] and interconnection cost, as illustrated in Table 6. Because the REAP zones cover a relatively small geographic area, a single capacity factor for each resource type is assumed in each zone. This assumption may be refined in future cycles.

Table 6: Renewable Potential and Capacity Factor by REAP Zone

Region			Solar		Wind	
REAP Zone	Utility	RTO	Potential MWac	Capacity Factor %	Potential MWac	Capacity Factor %
Greater Chicago	ComEd	PJM	1,445	23.9%	0	N/A
ComEd South	ComEd	PJM	2,346	24.2%	1,482	37.1%
1	ComEd	PJM	6,148	24.2%	4,710	37.5%
2	Ameren	MISO	2,122	24.5%	2,742	37.5%
3	Ameren	MISO	1,981	24.5%	1,899	38.3%
4	Ameren	MISO	7,470	25.1%	4,425	38.1%
5	Ameren	MISO	8,102	25.3%	201	36.5%

[98] *Capacity factor equals total annual generation possible from a resource divided by its nameplate capacity times hours in a year.*

6	Ameren	MISO	13,218	24.8%	813	39.5%
7	Ameren	MISO	5,864	24.6%	6,240	37.5%
Greater Peoria	Ameren	MISO	2,090	24.7%	2,142	37.5%
Southern IL	Ameren	MISO	19,671	25.2%	1,395	37.4%

Figure 28: Solar Potential

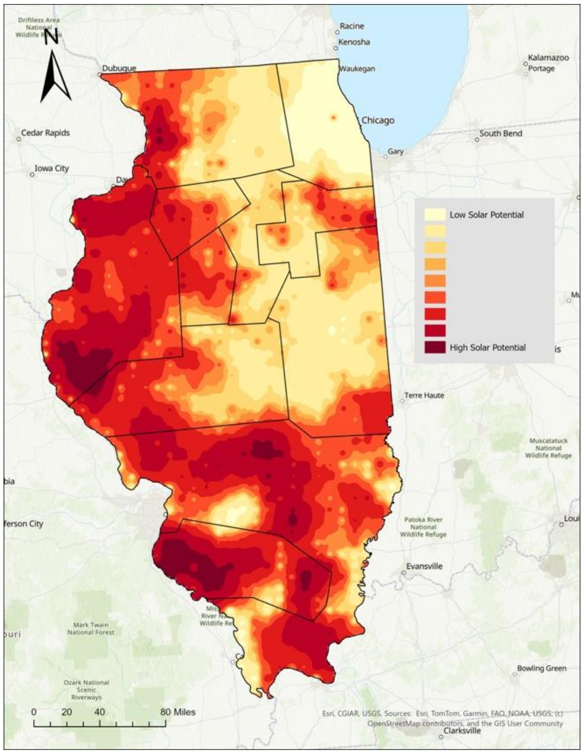
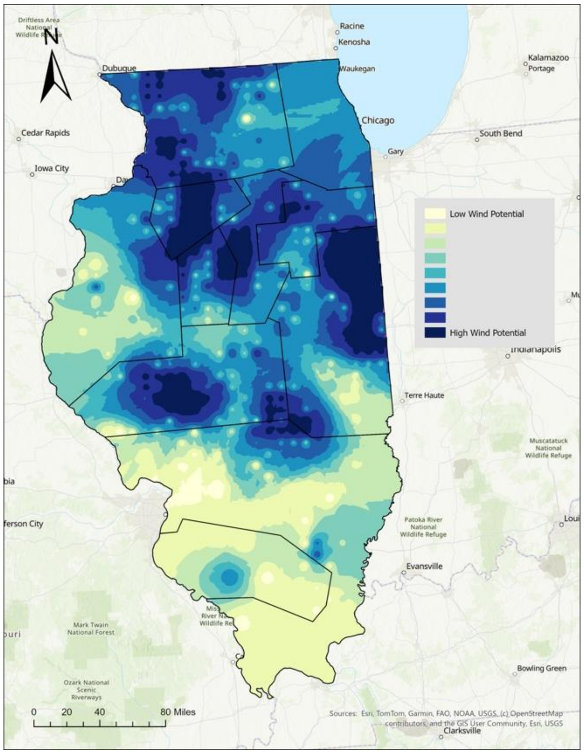


Figure 29: Wind Potential



Heat maps above show smoothed version of the NREL Supply Curves for developable solar and wind capacity. Interpolation was performed on the original dataset for purposes of illustration.

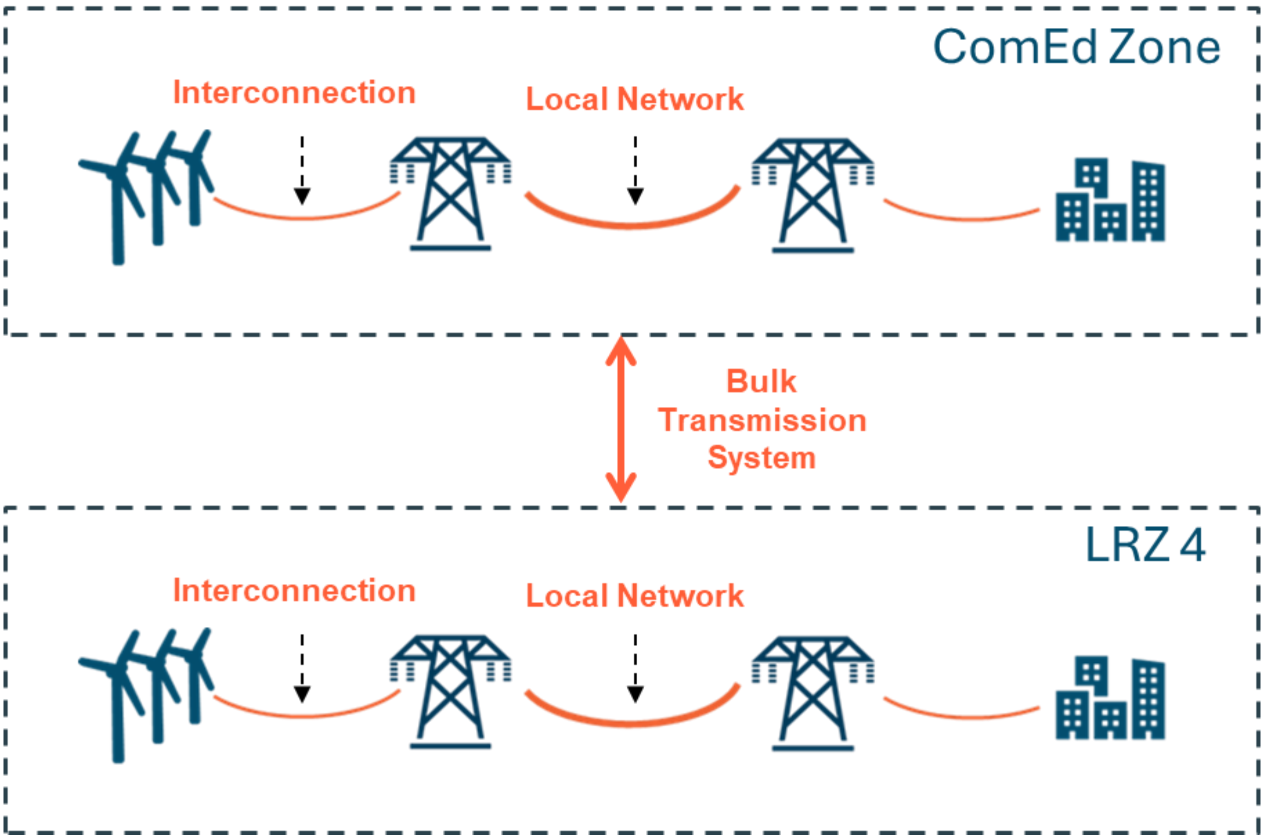
NREL publishes the results of its analysis for three different sets of siting assumptions/scenarios. The “Limited Access” scenario was selected, which applies a combination of restrictive setbacks, stringent environmental constraints, and national defense considerations. An additional haircut to the NREL potential was then applied to account for factors such as preservation of prime cropland and other land use considerations. As a result, the preliminary figures used in PLEXOS represent 20% of the solar potential and 50% of the wind potential estimated by NREL under the Limited Access scenario, a reduction that is designed to reflect the impact of socioeconomic, cultural, or competing land use considerations on land available for renewable development.[99] These assumptions can be further refined in future editions of the REAP based on the results of more granular geospatial analysis. Variation in solar or wind potential between regions is primarily a function of 1) resource quality (e.g., solar irradiance or average wind speed) and 2) siting constraints (e.g., setbacks, protected lands, slope exclusions, etc.).[100] The resulting solar and wind potential are reported in Table 6 and visualized in Figure 28 and Figure 29.

Transmission Representation

The REAP modeling considers three distinct types of transmission components as illustrated Figure 30:

+ **Bulk transmission system**: inter-zonal transfer capacity
+ **Local network**: transmission headroom within a zone that ensures electricity can be delivered from where it is generated or discharged to load centers
+ **Interconnection**: the "spur line" cost to connect generators to the closest substation

Figure 30: Illustration of Transmission Components



Power flow through the bulk transmission system is explicitly modeled, while simplifications are made to reasonably account for the cost of local network upgrades and interconnection in PLEXOS, as described below.

[99] "Draft 2025 Inputs and Assumptions for the 2024-2026 IRP Cycle," CPUC Energy Division (February 2025): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2024-2026-irp-cycle-events-and-materials/2025_draft_inputs_and_assumptions_public_slides.pdf.

[100] Lopez et al., "Solar Photovoltaics and Land-Based Wind Technical Potential and Supply Curves for the Contiguous United States: 2023 Edition," National Renewable Energy Laboratory (January 2024): https://docs.nrel.gov/docs/fy24osti/87843.pdf.

Bulk Transmission System

The bulk transmission system refers to the inter-zonal transfer capacity modeled in PLEXOS. The bubbles in Figure 31 represent the zones and the arrows connecting them make up the bulk transmission system. The numbers next to these arrows represent the existing line limits modeled. Hourly power flow is optimized and constrained by these limits. Inter-zonal transmission projects approved by the MISO and PJM boards through the LRTP and RTEP processes respectively have also been modeled (See Appendix A for details). Economic expansion of lines beyond these planned projects is currently not allowed in the model. In the future, additional scenario analysis could be conducted to study the impact of inter- zonal transmission expansion.

Figure 31: PJM & MISO Transmission Topology in 2030

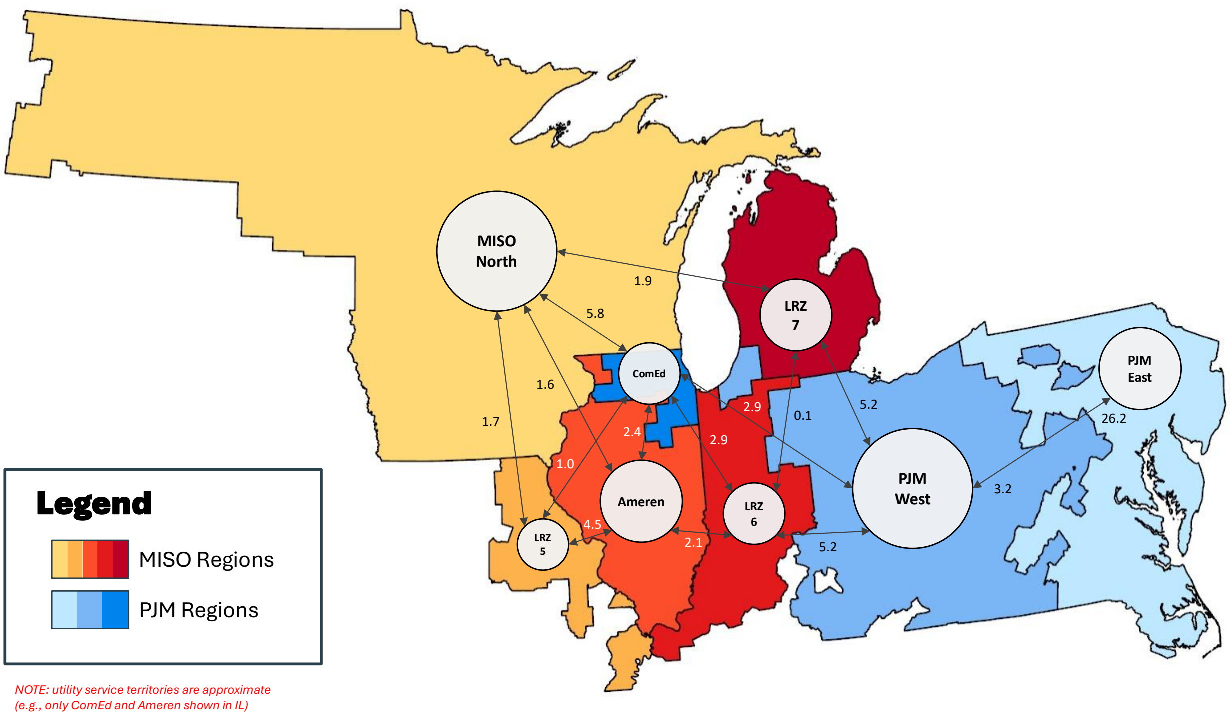
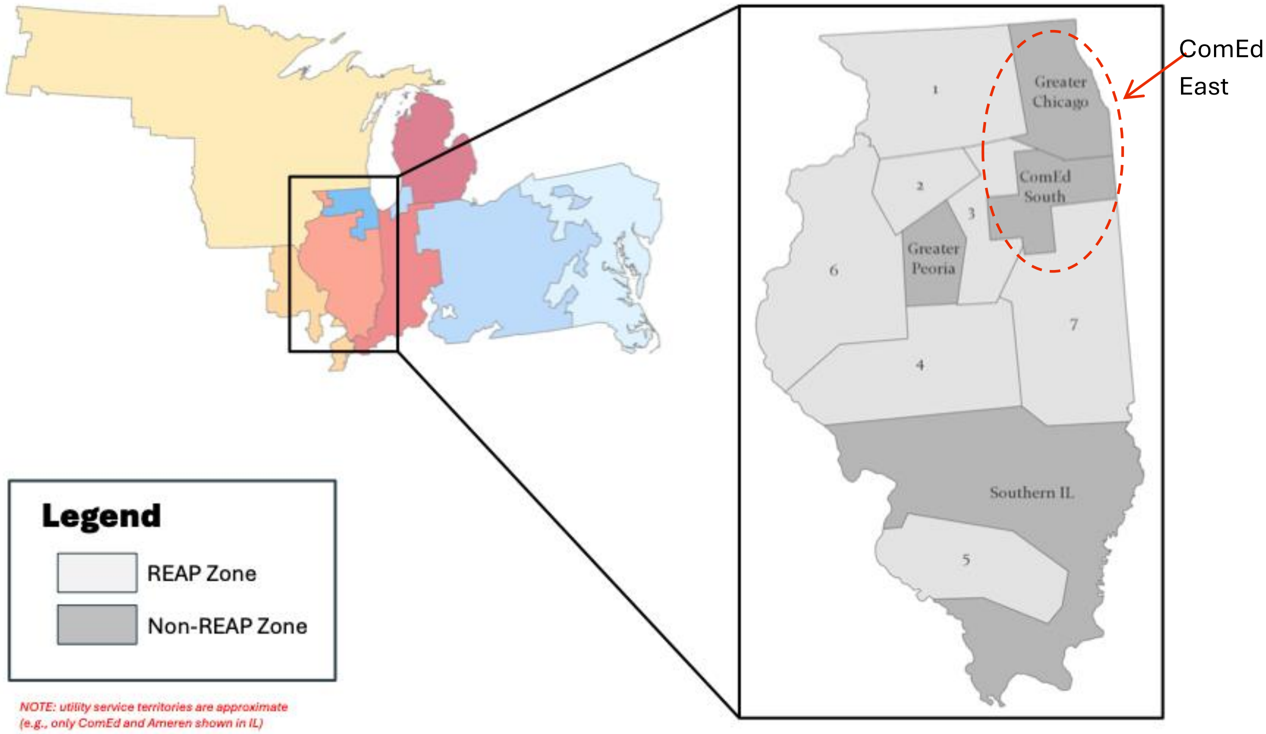


Figure 32: REAP Zone Map



Local Network Headroom and Upgrade Costs

Hourly power flow over the local network within each zone is not explicitly modeled in PLEXOS. Instead, the model keeps track of how much available "headroom" exists in each zone, i.e. how much additional power could feasibly be handled during the system's critical hours, which is assumed to occur between the hours of 4:00 – 8:00 PM from June through September. Given data limitations, it was assumed that no transmission headroom currently exists. This assumption can be easily updated once headroom data covering points over the entire system becomes available. Only one headroom constraint is currently modeled per REAP zone, but a more complex representation is possible, such as multiple constraints within each zone or constraints that span multiple zones.

The model also tracks the evolution of headroom over time as 1) fossil fuel unit retirements occur and 2) economic upgrades are selected to accommodate new resource builds required to meet load growth. These upgrades can be thought of as any network improvement that is required to deliver power to load, whether that involves increasing the capacity of an existing line or upgrading a substation. These types of cost are incurred when the model determines it is economic to alleviate a headroom constraint to build new resources within a given REAP zone. Additional headroom is created at no cost when fossil fuel units retire, per the schedule shown in Table 7.

Table 7: Fossil Retirement-Driven Transmission Headroom Creation by REAP Zone, Cumulative MW

REAP Zone	Region	2030	2035	2040	2045
Greater Chicago	**ComEd**	1,106	3,511	5,150	7,610

ComEd South	**ComEd**	0	0	0	1,445
REAP_Zone_1	**ComEd**	0	564	1,280	2,493
REAP_Zone_2	**Ameren**	0	0	0	0
REAP_Zone_3	**Ameren**	0	0	0	0
REAP_Zone_4	**Ameren**	1,701	1,701	1,882	1,993
REAP_Zone_5	**Ameren**	2,815	2,815	3,175	3,175
REAP_Zone_6	**Ameren**	0	0	84	84
REAP_Zone_7	**Ameren**	0	0	1,328	1,328
Greater Peoria	**Ameren**	1,538	1,538	1,538	1,538
Southern IL	**Ameren**	735	1,302	2,471	3,416

After the initial headroom from retiring fossil fuel units has been exhausted, if any existed at all, the cost of incurring additional headroom is assumed to be a step function. The first gigawatt of upgrades is estimated to cost $5,000/MW-mile[101], or $250,000/MW for an assumed 50 miles of high-voltage transmission lines. Each subsequent gigawatt of upgrades is assumed to cost 15% more than the previous tranche.[102] For the fifth gigawatt of upgrades selected by the model and beyond, costs are assumed to remain the same.

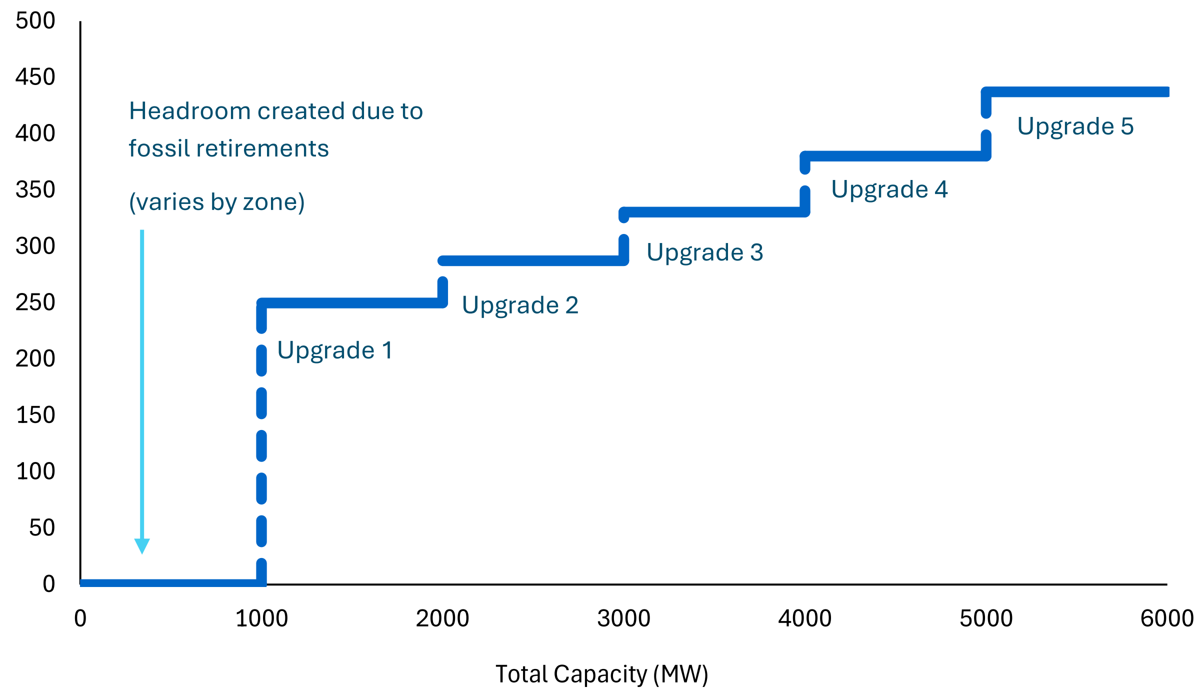
Table 8: Headroom Cost Schedule

Tranche	Unit Cost	Total Cost (50 Miles)
GW	**$/MW-mile**	**$/MW**
0-1	$5,000	$250,000
1-2	$5,750	$287,500
2-3	$6,613	$330,625
3-4	$7,604	$380,219
4+	$8,746	$437,285

[101] *Informed by latest approved transmission projects in PJM. Subject to refinement in future cycles. "Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board," PJM Staff (December 2023): https://www.pjm.com/-/media/DotCom/committees-groups/committees/teac/2023/20231205/20231205-pjm-teac-board-whitepaper-december-2023.ashx*

[102] *The 15% compounding assumption is based on a similar assumption used in New York's Coordinated Grid Planning Process. This assumption is also subject to refinement in future cycles. "2023-2042 System & Resource Outlook, Appendix H: Capacity Expansion Model Results," NYISO (July 2024): https://www.nyiso.com/documents/20142/46037616/Appendix-H-Capacity-Expansion-Model-Results.pdf.*

Figure 33: Local Network Upgrade Cost Illustration, $/kW



The power flow from different resource types varies across the day. Renewables are unlikely to be consistently producing at 100% of their nameplate capacity when the transmission system is most stressed. The critical deliverability window is assumed to be between the hours of 4:00 – 8:00 PM from June through September.[103] The contribution of solar and wind towards the transmission headroom constraint of each REAP zone is thus defined based on their average capacity factor in these hours. For example, if a resource consistently generates energy at 20% of its nameplate capacity in these hours, then five GW of this resource on a nameplate basis can be built before one GW of transmission headroom is exhausted and the next tranche of headroom upgrade cost is triggered. Additional details can be found in the appendix.

Interconnection Costs

Interconnection costs incorporate all expenses associated with building a new spur line or making upgrades to the substation closest to the generator. They are primarily a function of the distance between the site under development and its nearest point of interconnection to the existing grid. The values used for this study represent a capacity-weighted average of all candidate project areas in each REAP zone from NREL's supply curve data.[104] Interconnection costs are included in the total fixed cost of a resource and are incurred whenever that resource is built by PLEXOS. Cost details can be found in the appendix.

---

[103] *Additional deliverability windows will be added in future REAP cycles.*
[104] *Anthony Lopez et al., "Solar Photovoltaics and Land-Based Wind Technical Potential and Supply Curves for the Contiguous United States: 2023 Edition," National Renewable Energy Laboratory (January 2024): https://docs.nrel.gov/docs/fy24osti/87843.pdf.*

Findings

The modeling framework developed during this cycle will serve as a foundation upon which a more sophisticated representation of the state's electric system can be built once the necessary data becomes available. As such, the results discussed in this section should be viewed as preliminary and subject to revision in future cycles.

Even after applying land use filters, the state has approximately 70 GW of utility-scale solar and 26 GW of wind potential, which would be more than sufficient to meet the state's 50% RPS by 2040: This solar and wind potential sums to 239 TWh which is significantly higher than the 50% RPS target in 2040 of 109 TWh.[105] Additionally, distributed solar (potential not estimated here) can also play a meaningful role. Thus, Illinois is not constrained in renewable potential required to meet its RPS target.

23 GW of transmission headroom will be created due to fossil retirements to meet CEJA requirements which can help integrate new resources: These retirements are concentrated near population centers, such as the Chicago and St. Louis metropolitan areas. However, every REAP zone besides 2, 3 and 6 could experience at least some level of retirement by 2045, thus available headroom. New resources can utilize this headroom before transmission upgrades are needed or built.

This headroom may be utilized to integrate a mix of renewable resources, storage and firm resources to maintain reliability while meeting CEJA goals: As described in Chapter 2, in addition to renewables to meet the RPS, the model selects a mix of storage and firm resources such as nuclear or H_2-ready combustion turbines to provide balancing on different timescales and maintain reliability. Based on the timing of resource additions and fossil retirements, the headroom created by the latter may be utilized to integrate a mix of new resources.

New resource needs to meet the RPS and maintain adequacy will likely exceed transmission headroom created due to retirements; transmission upgrades will likely be necessary: Approximately 35 GW of effective capacity from new in-state resources and/or firm imports will be required to maintain reliability in Illinois given assumed load growth and fossil retirements. Additionally, 25+ GW of new utility-scale solar and wind is selected by the model to meet the 50% RPS. This is higher than the 23 GW of transmission headroom created due to fossil retirements suggesting some transmission upgrades will be necessary. An "all options on the table" approach including different resource types, NWAs and ATTs will help limit upgrades and lead to the most economical solution.

Generation and transmission buildouts selected in the three scenarios presented in Table 5 follow in the rest of this section.

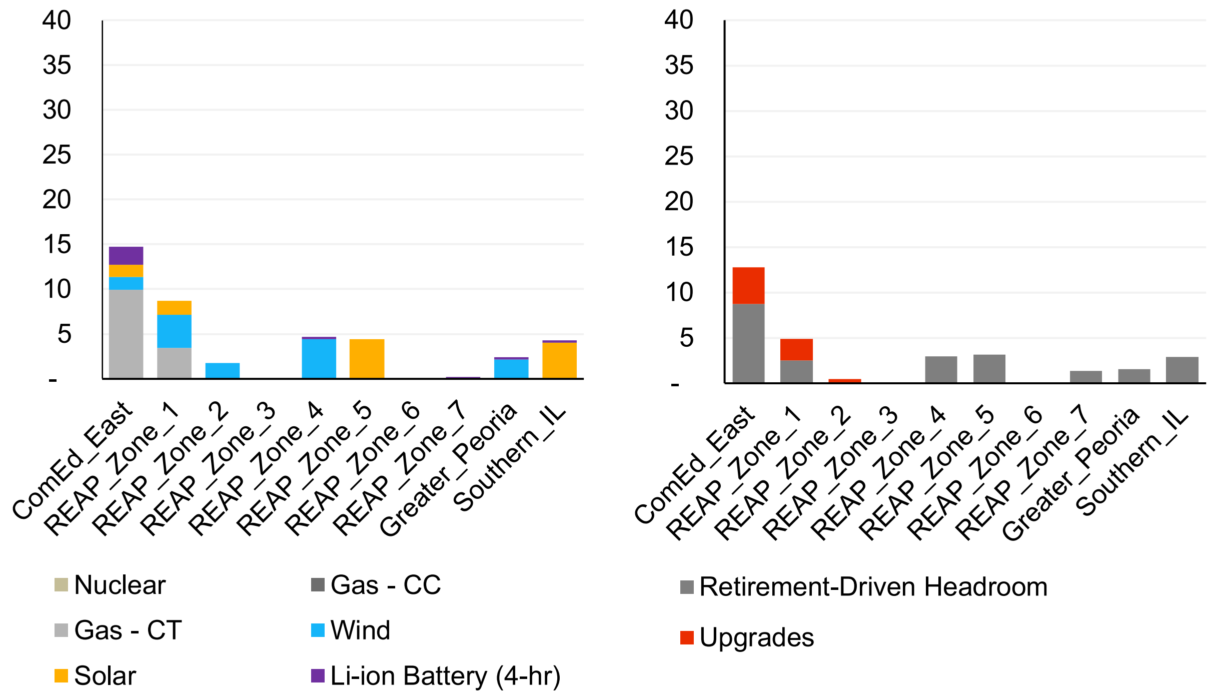
---

[105] *Illinois 2025 Long-Term Renewable Resources Procurement Plan - https://ipa.illinois.gov/renewable-resources/long-term-plan.html.*

Optimal Generation and Transmission Buildout by REAP Zone Across Modeled Scenarios

New H_2-Ready Combustion Capacity Allowed

Figure 34: Installed Capacity of Resources Selected (Left) Using Transmission Headroom and Upgrades (Right) by REAP Zone by 2045 When New H_2-Ready Combustion Capacity is Allowed (GW)



In these charts, the Greater Chicago and ComEd South regions have been aggregated into a single "ComEd East" region for simplicity. These regions were modeled separately in PLEXOS. ComEd East and REAP Zone 1 are comprised within the ComEd Zone in PJM. The remaining zones are comprised within LRZ 4 in MISO and are referred to as such in the detailed description below.

Figure 34 shows REAP zone specific builds and transmission headroom in the scenario where new in-state H_2-ready combustion capacity is allowed. Load growth increases the need in ComEd zone by 9 GW by 2045. Additionally, approximately 11 GW of fossil retirements also take place in this zone. The model selects 8 GW of capacity purchases[106] from the rest of PJM leveraging the inter-zonal transmission capability. 14 GW of H_2-ready capacity, 2 GW of storage and 8 GW of utility-scale renewables are selected within ComEd zone. The model first leverages the 11 GW of transmission headroom created due to retirements in this zone. Once that headroom is exhausted, 6.4 GW of transmission upgrades are selected by the model to ensure these resources can be delivered to load in the ComEd zone.

LRZ 4 also experiences significant fossil retirement and 3 GW of load-growth driven increase in need by 2045. 10 GW of capacity purchases from the rest of MISO are selected by the model to maintain reliability in LRZ 4. While no firm capacity is selected in LRZ 4, the significant renewable potential in LRZ 4 is accessed to help the

[106] *Since this resource exists outside the state and does not impact in-state land use or transmission upgrades, it is not shown in the figure.*

state meet its RPS. 17 GW of utility-scale renewables and 1 GW of storage are selected in LRZ 4. These resources are placed in zones where retirements occur to leveraging the transmission headroom created. No incremental transmission upgrades are required in LRZ 4 given assumptions made and resulting model selections. Assumptions will continue to be refined in future cycles.

New In-State Combustion Capacity Not Allowed

Figure 35: Installed Capacity of Resources Selected (Left) Using Transmission Headroom and Upgrades (Right) by REAP Zone by 2045 When New In-State Combustion Capacity is Not Allowed (GW)

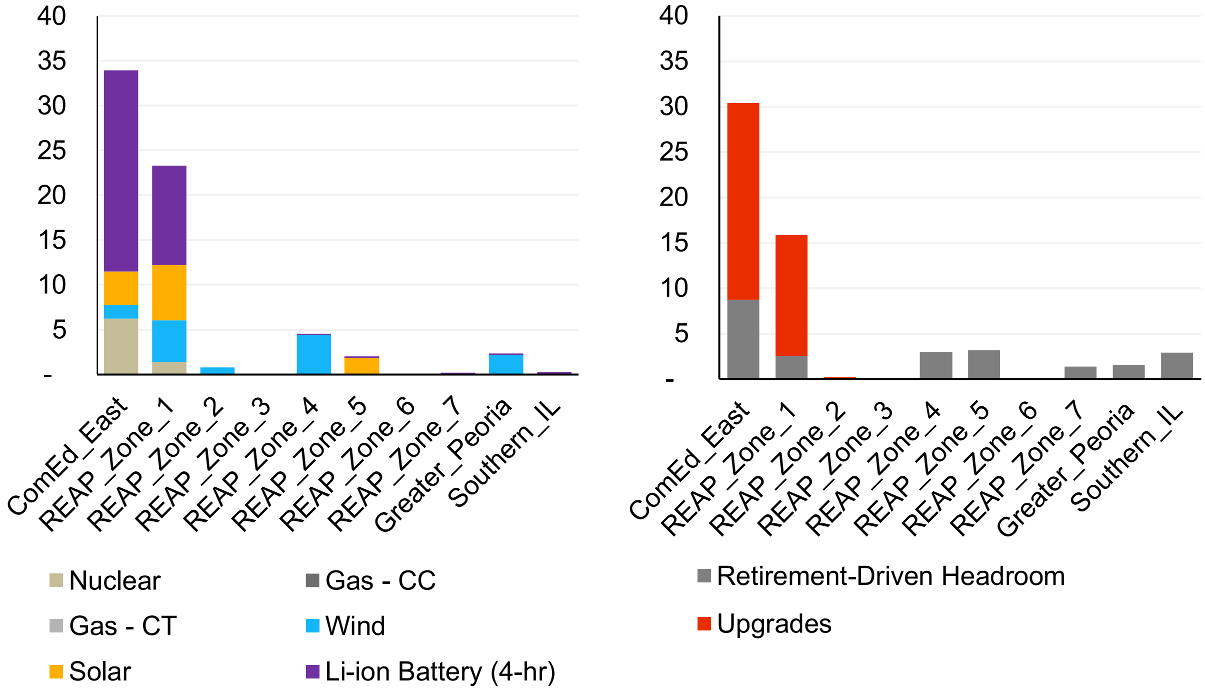


Figure 35 shows REAP zone specific builds and transmission headroom when new in-state combustion capacity is not allowed. As shown in Figure 23, significantly more storage and nuclear are selected in the absence of new combustion resources. These are placed in the ComEd zone where the combustion resources were also placed (See Figure 34). While state-level renewable builds remain relatively unchanged between the two scenarios, 8 GW of renewable builds shift from LRZ 4 to ComEd given the balancing services provided by storage. This higher overall resource build in the ComEd zone also drives up the requirement for transmission upgrades under current assumptions. The ability of storage, other NWAs and ATTs to delay/avoid such upgrades will be studied in more detail in future cycles. Less resource capacity is selected in LRZ 4, still within zones with headroom created by fossil retirements and avoiding upgrades.

Net Imports Not Allowed by 2045

Figure 36: Installed Capacity of Resources Selected (Left) Using Transmission Headroom and Upgrades (Right) by REAP Zone by 2045 When Net Imports Are Not Allowed (GW)

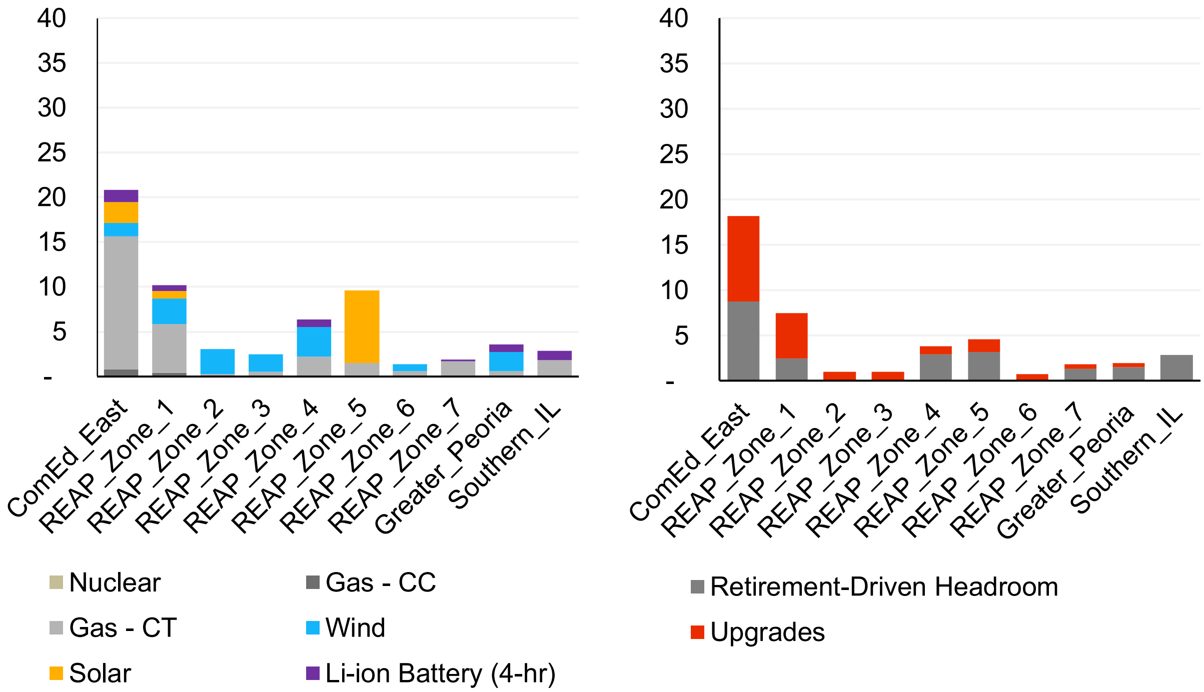


Figure 36 shows REAP zone specific builds and transmission headroom when net imports are not allowed. In this scenario, the total effective capacity need for reliability must be met with in-state resources. Imported energy over the year must also be offset with equivalent exports of clean energy. Comparing Figure 22 to Figure 24, all 19 GW of capacity purchases are replaced with 17 GW of incremental in-state firm capacity and 2 GW of incremental storage in this scenario. 1 GW of incremental wind is also added to ensure that Illinois remains self-sufficient on an annual energy basis. This higher need for in-state resources also drives the need for more transmission upgrades. Resource builds are lower in REAP zones 2,3 and 6 relative to neighboring zones. This is because no fossil retirement-driven transmission headroom exists in these zones. Any resource built in these zones will immediately incur a transmission upgrade cost. The model thus elects to build resources in neighboring zones where the resource costs are comparable, but deliverability is cheaper.

Recommendations

The major accomplishments of this REAP within Strategic Element 3 include geocoding of REAP zones, building a modeling framework to co-optimize generation and transmission builds within each REAP zone, co-ordination with IDNR, continued collection of datasets and analysis to estimate the suitability of land for renewable and transmission development. Future REAP cycles can continue to build on this foundation in the following ways.

Continued Analysis to Estimate Suitability of Land for Infrastructure Development

Continued refinement of REAP zones is necessary to ensure they are actionable and can effectively feed into regional planning processes to identify solutions. Continued collaboration with IDNR and carrying forward the suitability analysis conducted for this REAP can help refine REAP zone boundaries. Additionally, this suitability analysis can partly inform mapping of long-term resource additions to specific substations and inform downstream analyses illustrated in Figure 13.

Existing fossil plants are generally concentrated near major population centers like Chicago and St. Louis. When they retire, ample transmission headroom will be created that new resources can exploit. The existing transmission system is also denser near population centers, so spur lines required to interconnect new resources will be comparatively shorter. Given the high load growth projected in the ComEd zone, significant resource builds are selected in these zones in the scenarios studied. However, there may be siting restrictions (that may vary by resource type) and/or cost premiums for infrastructure development near population centers given scarcity of land, safety and other factors. These factors should be considered in further detail and reflected in the costs and potential capacity of candidate resource and transmission investments available to the model.

Continued Analysis to Identify Infrastructure Needs and Associated Land Use Impacts

Assumptions related to the transmission system should continue to be refined to ensure future transmission needs are identified with more precision. The interconnection costs in zones near population centers should be refined to reflect siting restrictions described above. The objective in this REAP update was to demonstrate the ability to model the local transmission network within each REAP zone. Given data limitations, simplifying assumptions were made, such as assuming existing transmission headroom in each REAP zone is zero; modeling a single deliverability constraint within each REAP zone; and modeling the same network upgrade costs across all REAP zones. Continued collaboration with the RTOs, utilities and other relevant stakeholders can help refine these assumptions and the resulting model selections. With a more refined view of where resource and transmission development may be needed, land use impacts can be studied in more detail.

Additional scenarios should be explored, as described in Chapter 2. The same scenario design considerations highlighted there will have implications for infrastructure and land use impacts.

Continued Community Outreach

The community outreach efforts this REAP cycle are described in Chapter 1. As the results from the REAP become increasingly actionable, it will be important to continue outreach to communities that may host energy infrastructure to ensure that questions and concerns can be addressed proactively.

Strategic Element 4: Effective Transmission Planning and Utilization

Strategic Element 4, *Effective Transmission Planning and Utilization*, explores how to meet the transmission needs identified in Strategic Element 3 through both conventional and innovative approaches. This chapter begins by exploring updates on regional interconnection reform, then summarizes transmission needs within the REAP zones as identified in Chapter 3, and, lastly, explores in depth how Advanced Transmission Technologies (ATTs) and Non-Wires Alternatives (NWAs) can contribute to meeting those needs. Collectively, these sections define the analytical and policy framework Illinois can use to ensure that transmission investments support CEJA's renewable and clean-energy goals cost-effectively.

Highlights from the 2024 REAP

Focus on Interconnection Reform and Transmission Planning Coordination

The 2024 REAP identified transmission and interconnection reform as central to enabling Illinois' clean energy transition. In the prior REAP, Strategic Element 4 emphasized that current RTO interconnection processes were major barriers to renewable development, particularly in PJM where severe queue backlogs and serial restudies delayed projects and increased costs. The 2024 REAP also found that while MISO's interconnection throughput was higher, both RTOs needed to improve coordination, reduce study timelines, and proactively plan transmission infrastructure to support the scale of renewable deployment required under CEJA. The REAP called for Illinois to advocate within MISO and PJM for reforms to streamline interconnection studies, better align transmission expansion with policy-driven generation needs, and ensure the fair treatment of projects in the backlog.

The REAP also underscored the importance of improving coordination between RTO transmission planning and the state's policy targets. It recommended that ICC continue to provide input into MISO's Long Range Transmission Planning (LRTP) and Futures studies, and advocate for PJM to adopt comparable scenario-based planning that integrates public policy drivers such as fossil phaseouts and renewable targets. The REAP framed proactive, policy-aligned planning as essential to reducing reliance on incremental network upgrades triggered through interconnection studies.

Leveraging REAP Zones to Align Planning and Interconnection Reform

Strategic Element 4 of the 2024 REAP also highlighted the potential for REAP zones to serve as a bridge between Illinois' state policy goals and regional transmission and interconnection planning processes. The report proposed using REAP zones to inform RTO studies and to identify locations where proactive transmission investments could support renewable integration cost-effectively. Rather than prescribing specific projects, the REAP emphasized the value of incorporating state-defined planning priorities, such as fossil retirements, into ongoing RTO planning cycles.

The 2024 REAP also recognized that improving coordination across planning and interconnection processes would be a gradual effort, requiring engagement with both MISO and PJM as they implement their own transmission and interconnection reforms. It recommended that the ICC continue to participate in stakeholder forums and regional planning initiatives to ensure Illinois' policy needs are reflected in future transmission portfolios and interconnection queue reforms. In doing so, the REAP framed REAP zones as a foundational concept that can evolve alongside federal and regional reforms, providing a structure through which Illinois can align its clean energy priorities with RTO planning and project selection over time.

Interconnection Queue Updates

As discussed in the Introduction, interconnection reform remains one of the most consequential changes affecting renewable deployment since the 2024 REAP. Both MISO and PJM have implemented new interconnection procedures in response to FERC Order No. 2023, which replaced the previous "first-come, first-served" approach with a "first-ready, first-served" cluster study process. These reforms are designed to streamline the interconnection process through standardized timelines, increased project readiness requirements, and improved coordination of affected system studies. Together, they aim to address the bottlenecks identified in the 2024 REAP, specifically queue backlog, cascading restudies, and uncertain upgrade costs, and to create a more predictable and transparent pathway for new renewable and storage resources in Illinois.

While both RTOs have made meaningful progress, the impacts of these reforms are still unfolding. PJM continues to process its backlog under pre-Order 2023 rules before new requests can enter the revised process, and implementation delays may continue to constrain interconnection opportunities in the ComEd zone in the near term. MISO, having already utilized a clustered study framework, is further along in aligning with the new standards but still faces challenges in meeting uniform study timelines and integrating readiness requirements consistently across study groups. Both RTOs are also working to enhance coordination on affected system studies, which is an issue of particular relevance for Illinois projects located near the MISO-PJM seam, where interregional dependencies often drive additional costs and delays. Continued monitoring of these reforms is critical to ensure they yield measurable improvements in throughput and transparency.

In addition to implementing reforms, both RTO's have piloted using technology to accelerate interconnection studies. PJM announced in April 2025 a collaboration with Google and Tapestry to use artificial intelligence to streamline interconnection studies.[107] At the same time, MISO announced benchmarking study results comparing Pearl Street Technologies' SUGAR to MISO's existing tools. The study indicated that "SUGAR can be used confidently in MISO's DPP Phase 1 studies."[108] These are encouraging steps forward in the RTOs expanding their use of technology to meet the needs of the interconnection queue.

This REAP's IPF builds on these reforms by linking proactive transmission planning with the state's interconnection needs. The previous chapter estimated transmission headroom that may be created due to fossil retirements in each REAP Zone and also provided preliminary estimates of incremental upgrades that may be needed to enable the delivery of resources to satisfy demand and meet policy targets. By assessing headroom within a proactive planning construct, rather than waiting for projects to trigger upgrades through the queue, this REAP seeks to co-optimize transmission development and generation needs. This approach aims to more efficiently use existing infrastructure, reduce delivery costs, and help ensure that renewable projects can advance in areas with both resource potential and deliverability. Given that at this time only a

[107] *PJM Inside Lines (2025): https://insidelines.pjm.com/pjm-google-tapestry-join-forces-to-apply-ai-to-enhance-regional-planning-generation-interconnection/.*
[108] *MISO's Benchmarking of Pearl Street SUGAR (April 15, 2025): https://cdn.misoenergy.org/MISO%20Benchmarking%20of%20Pearl%20Street%20SUGAR697461.pdf.*

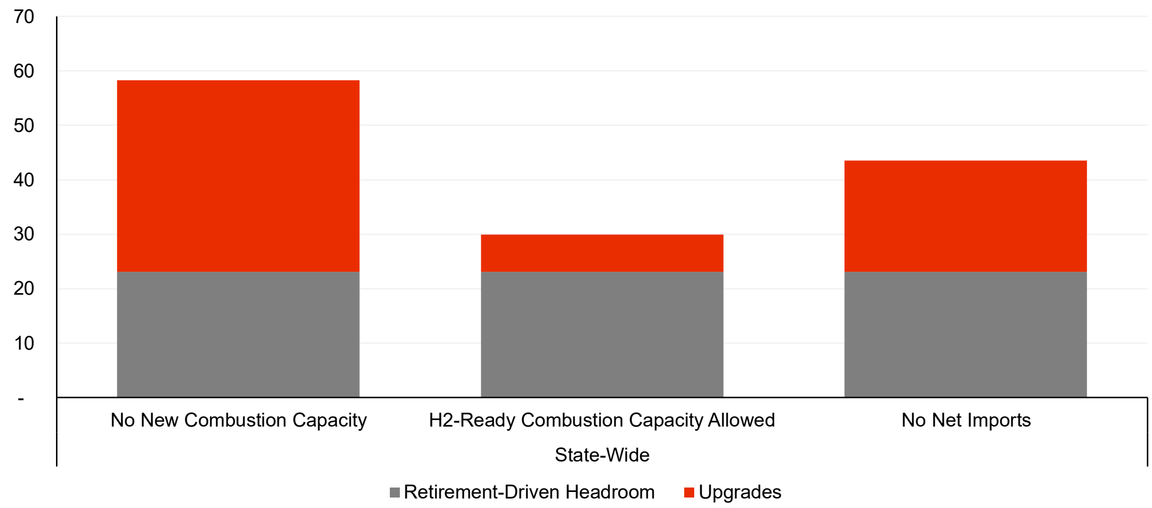
minority of projects make it from the interconnection queue to commercial operation, proactively creating and targeting transmission headroom can help increase the success of projects reaching commercial operation in the interconnection queue. Strategic Element 5 then extends this discussion by examining recent changes in Surplus Interconnection Service processes at both RTOs, which can enable quicker interconnection in areas with headroom, enabling projects to directly benefit from proactive transmission planning.

REAP Zones and Transmission Needs

Integrated Planning Approach to Identifying Transmission Needs for REAP Zones

As described in Chapter 3, an IPF was developed this cycle to co-optimize generation and transmission builds. Over the next twenty years, retirements of existing fossil capacity in the state (up to 23 GW) may provide access to transmission headroom that can be utilized to integrate new resources. However, the resource portfolio is also projected to grow significantly to meet load growth and state policy goals. The IPF identifies that across the scenarios assessed in this REAP cycle, 7-35 GW of transmission upgrades may be needed in Illinois, as seen in Figure 37. The range in headroom needs reflects the variety of pathways to achieve the state's policy targets. ATTs and NWAs may also help reduce the need for conventional transmission upgrades, as explored in the rest of this chapter. Future analysis will examine potential changes in the transmission system in more detail as both loads and generation resources evolve.

Figure 37: Statewide Transmission Headroom and Upgrades by Scenario by 2045 (GW)



Current Landscape of Advanced Transmission Technologies and Non-Wires Alternatives

In addition to traditional grid investments, such as transmission lines or large-scale generation resources, there are other investments that may improve utilization of existing generation, transmission and distribution assets. ATTs and NWAs, for example, have the potential to address some transmission and distribution (T&D) system needs, potentially reducing or deferring the need for more time- and capital-intensive upgrades. These investments include both hardware and software solutions, such as advanced conductors, Dynamic Line

Ratings (DLRs), Advanced Power Flow Controls (APFCs), Topology Optimization (TO) and Virtual Power Plants (VPPs).

The value of ATTs and NWAs is location-specific and depends on a variety of factors, including but not limited to local grid conditions, future system needs, integration with existing hardware or software, and the cost of implementation relative to conventional approaches. Their applicability may also evolve over time, as technologies mature and system conditions change. Incorporating these approaches into a broader, integrated planning framework will allow policymakers and planners to consider them alongside traditional alternatives when determining the most cost-effective and reliable path forward for Illinois ratepayers. Implementing certain ATTs, particularly hardware-based solutions like DLRs or APFCs, may require complementary investments in information technology systems, operational protocols, and workforce training. This additional cost and complexity should be factored into planning and procurement decisions.

This REAP provides the Commission with a framework for considering where and when ATTs and NWAs can provide value in enabling the deliverability of renewable energy. Rather than prescribing specific solutions, this REAP aims to develop a broader understanding of how ATTs and NWAs can help meet identified transmission needs and complement other solutions. ATTs and NWAs are not the only tools capable of enhancing system performance and facilitating renewable integration. So, this REAP focuses on clarifying the circumstances in which they should be considered and ensuring that both novel and conventional solutions are evaluated on a level playing field.

Defining and Characterizing Advanced Transmission Technologies

For the purposes of this report, the term ATTs refers to Advanced Conductors, Dynamic Line Ratings (DLRs), Advanced Power Flow Controls (APFCs), Topology Optimization (TO), and Storage as a Transmission-Only Asset (SATOA). Potential benefits of these technologies include improved visibility into grid asset operations, reduced congestion, operational flexibility, and outage mitigation.

+ **Advanced conductors,** including high-performance and composite-core designs, are transmission line technologies that can carry more power than conventional conductors of a similar diameter. These conductors can often operate at higher temperatures with reduced thermal sag, increasing transfer capability along existing rights-of-way. Use cases include uprating reconductored lines to provide additional headroom for new generator interconnections, deferring the need for new construction in areas with siting challenges, and improving system efficiency by reducing line losses.
+ **Dynamic Line Ratings rely** on real-time sensors to adjust line and transformer ratings in response to granular data on environmental conditions (e.g., ambient temperature, wind speed, etc.). The primary use case for DLRs is leveraging real-time visibility into system conditions to increase or decrease ratings such that the line is operating at the optimal level given environmental conditions. In cases where line ratings can be increased, DLRs are capable of relieving transmission congestion, in particular during winter months when the combination of radiative and wind cooling allow for greater power flow across specific lines.
+ **Advanced Power Flow Controllers (APFCs)** are power electronics with the ability to change the reactance of a transmission or distribution line by injecting voltage, allowing system operators to alter the direction of power flow or line capacity. Unlike traditional power flow controls with electromechanical components like phase-shifting transformers, APFCs allow for more rapid adjustments in a continuous fashion. Because the objective is to redirect power from congested areas of the grid to other circuits, they are most effective in highly meshed networks.

- **Topology Optimization** refers to the use of software models to process real-time grid data and efficiently route power around congested areas of the system by opening or closing circuit breakers in a substation. The ability to rapidly identify and deploy new network configurations can avoid the need to re-dispatch generation, reducing system costs. Note that there is a steep learning curve that system operators must climb to effectively deploy topology optimization which may increase the cost and lead time required to implement these solutions.
- **Storage as a Transmission Only Asset:** Although storage has the potential to create value by (1) providing transmission services or (2) performing energy arbitrage, this report focuses solely on assets under direct control of the grid operator that are compensated through regulated transmission rates. Although opportunities exist to "value stack" the various use cases of storage, most regulatory structures do not yet support this approach. Examples of how storage might be used exclusively for transmission services include absorbing excessive power after a line goes down to avoid thermal overload elsewhere in the system, providing voltage support, injecting reactive power, or mitigating the impact of an outage on customers.

Certain situations lend themselves to compatibility with many types of ATTs, such as the need to rapidly alleviate a targeted constraint, circumvent a siting challenge, or avoid a costly overbuild. In other words, if conventional approaches to building transmission are too expensive or take too long, ATTs may be able to offer a tailored solution that can be deployed quickly, delaying or avoiding altogether the need for a costly new transmission line. However, the suitability of the technologies discussed in this report varies on a case-by-case basis, with certain conditions enabling better performance and others limiting their value, as shown in Table 9.

Table 9: Enabling Conditions for ATTs to Support Renewables Integration

ATT	Enabling Conditions for Supporting Renewables Integration	Factors that Limit Renewable Integration Value	Key Insights for REAP
DLR	+ Environmental factors resulting in cooler lines (e.g., shade, cross winds, ice accumulation, etc.) + Communications architecture to collect and interpret sensor data + Advanced data management to store and display sensor data	+ Timing of system peak may impact value (i.e., limited applications in summer peaking system)	+ Promising outside peak-summer hours + Target windier corridors in Central and Western Illinois where correlation exists between wind generation, congestion, and cooler weather conditions + Foundational IT is a prerequisite
Advanced Conductors	+ Siting limitations (e.g., densely populated or environmentally sensitive)	+ Targeted line is binding constraint and neighboring lines have no additional headroom (esp. in non-meshed networks) + Cost of materials, plus protection systems and	+ Suited to situations where line constraints are clearly binding but siting is challenging + Especially relevant in areas with high renewable generation and load growth

		potential upgrades to substations	
APFCs	+ Network configurations with many redundant lines, such as highly meshed system, where power can be redirected to alternate routes	+ Networks with radial lines (e.g., rural areas) limit ability to redirect power to alternate routes	+ Useful at relieving recurring interface constraints + Operations integration is key to successful deployment + Complementary to conventional upgrades + Test controllability on meshed networks
Topology Optimization	+ Requires the same underlying grid configuration as APFCs + Software to identify new network configurations in real time	+ Same as APFCs	+ Highest value when leveraging existing switchable network + Benefits hinge on high-quality network models, contingency screening, and established operating playbooks, not large capital expenditures + Coordination between utility and RTO is necessary
SATOA	+ Areas where local loads may be unsustainable in the event of a planned or forced transmission outage + Demand for reliability services like voltage support	+ Must be planned as a transmission solution under grid operator control to ensure reliability	+ Provides faster, right-sized alternative (or complement) to wires

Defining and Characterizing Non-Wires Alternatives and Other Broad Solutions

This report explores four broad categories of NWAs: distributed energy resources, energy efficiency, demand response, and virtual power plants. These approaches seek to defer or avoid investment in primarily distribution infrastructure by locating assets like battery storage, distributed generation, or flexible loads at strategic nodes throughout the grid. NWAs can be broadly distributed across a utility service territory and have the potential to provide systemwide energy or capacity benefits. However, their ability to alleviate congestion or improve transmission system reliability is inherently locational. Because transmission needs emerge at specific substations or along specific corridors, understanding where and how NWAs can provide grid-relief value is essential to identifying opportunities.

+ **Distributed Energy Resources (DERs):** DERs encompass a diverse set of small-scale, grid-connected technologies that generate, store or manage electricity close to where it is used. Battery storage and distributed solar are a few of the most prevalent technologies that fall under the wide umbrella of DERs. With a targeted approach to deployment, these solutions may be able to delay or avoid substation upgrades or increase system reliability. However, without an appropriate program design to either encourage or schedule dispatch of these resources during periods of need, system operators may not be able to rely on DERs as an alternative to conventional line or substation upgrades.
+ **Demand Response (DR):** DR is the intentional shifting or reducing of electricity usage by consumers in response to grid conditions, price signals, or utility/RTO programs to support system reliability. There are many different types of DR (sometimes referred to as demand flexibility), ranging from residential programs for managed EV charging and smart thermostats to commercial or industrial offerings that compensate participants who shed load during emergency events. Each of these approaches, if implemented thoughtfully, has the potential to eliminate a portion of on-peak load or shift it to off-peak hours, delaying the need for costly line or substation upgrades. Alternatively, they may simply serve as a bridge to a more durable solution that requires substantial lead time to construct. Incremental investment in tailored, local solutions may also generate savings for ratepayers by avoiding large upfront investments in assets like new transmission lines that remain underutilized for years to come.
+ **Virtual Power Plant (VPP):** A VPP aggregates diverse DERs, such as battery storage, solar PV, demand response, and managed electric vehicle charging, into a single, flexible portfolio that can act like a traditional power plant. When coordinated through advanced communications and control platforms, VPPs can provide load shifting, frequency response, and other grid services that support reliability and reduce congestion. In areas where transmission or distribution upgrades are costly or delayed, VPPs can offer a scalable non-wires alternative by leveraging existing customer-sited assets. Their effectiveness depends on enabling participation frameworks, standardized communications, and market mechanisms that allow aggregated DERs to respond to system needs in real time. Additionally, like individual DERs, the ability of a VPP to meet transmission system needs depends on whether they can provide targeted contributions in a specific location of the transmission network.
+ **Energy Efficiency (EE):** The term energy efficiency refers to any initiative to reduce overall electricity consumption through investments in things like more efficient appliances, building systems, or industrial processes. By lowering demand, efficiency programs can defer the need for new generation and distribution upgrades while reducing customer bills and emissions. Targeted deployment of energy efficiency in constrained areas can be particularly effective in mitigating peak loads or deferring local capacity projects. However, realizing these locational benefits requires data-driven program design and coordination between utilities, regulators, and local implementers to align savings potential with grid needs.

In practice, the process of identifying where to locate these investments, proving they can perform reliably when needed, and forecasting their value years ahead of time remains a significant barrier to implementation. As a result, there are many examples of utilities successfully deploying broad-based, passive energy efficiency measures but relatively few cases in which NWAs have been deployed to target a specific deferral need. To ensure Illinois ratepayers receive net benefits from investments in NWAs, ICC must carefully weigh the savings passed on to ratepayers (e.g. investment costs avoided by the utility) against the costs to ratepayers of the program (e.g. compensation offered to program participants). For an in-depth analysis of how to value these types of resources, see *The Value of, and Compensation for, Distributed Energy Resources in Illinois*.[109]

Table 10: Enabling Conditions for NWAs to Support Renewables Integration

NWA	Enabling Conditions for Supporting Renewables Integration	Factors that Limit Renewables Integration Value	Key Insights for REAP
DER	+ Highly localized need in a part of the grid that does not require broader upgrades + Distributed resources already concentrated near congested node + Software that allows for granular dispatch of resources and real-time monitoring capabilities to ensure performance and accurate compensation	+ Marginal value of resource declines as penetration increases + Estimating value of deferred investments is non-trivial, requiring detailed knowledge of system topology and load, as well as "baseline" contribution of each resource to system peak	+ Can delay or reduce generation and transmission investments if dispatch is aligned with load in critical times + Areas with high existing concentration of behind-the-meter resources that are underutilized may benefit from investments to align their dispatch with system needs110
DR	+ Similar considerations as DERs + Large, flexible loads with adequate shift potential (e.g., EV charging) + Ability to automate participation or at least reduce burden on participant (e.g., smart thermostat)	+ Similar considerations as DERs + Unless dispatch is managed by utility, reliable performance likely requires large numbers of participants in case uptake is low (e.g., EV charging)	+ May offer opportunities to reduce system peak in stressed parts of the grid at low cost to utility, but incentivizing participation in voluntary programs is likely to be challenge; uptake of utility-managed programs may be low
VPP	+ Concentration of controllable DERs near congested nodes + Aggregator platform with telemetry and dispatch visibility + Clear participation rules and locational compensation	+ Performance uncertainty from device diversity and attrition + Complex verification and settlement processes + Barriers to aggregation across utility or RTO boundaries	+ Suited for zones with high DER penetration + Can defer smaller upgrades if coordination is reliable + Most effective when aligned with RTO aggregation rules

[109] *Energy and Environmental Economics, "The Value of, and Compensation for, Distributed Energy Resources in Illinois," January 2025: https://www.ethree.com/wp-content/uploads/2025/01/ICC-VDER-Report-FINAL-2025-1-17.pdf.*
[110] *These investments may, for example, include software capabilities described under enabling conditions or storage to charge excess rooftop solar in the middle of the day and discharge it either to the customer or the grid during the net peak later in the day.*

EE	+ Similar considerations as DERs + Stable funding and programs targeting high-load areas	+ Limited dispatchability and uncertain persistence of savings + Long lead times and adoption barriers + Difficult to scale for bulk transmission impacts	+ Reduces load and can defer local capacity investments + Increases in system value when paired with DR or VPP

Framework for Evaluation

The Commission's Order approving the 2024 REAP mandated consideration of ATTs and NWAs as potential approaches for meeting identified transmission needs. While detailed engineering studies are not part of the REAP, this report outlines a framework that can be used to conduct benefit-cost analysis for ATTs and NWAs under different use cases and system conditions once the necessary data is available.

Table 11: Framework for Considering Advanced Transmission Technologies and Non-Wires Alternatives

Step 1: Identify System Constraints and Conventional Upgrade Costs
a. Identify the *types* of system needs that emerge from REAP portfolios (e.g., headroom constraints and congestion on major interfaces). **b.** Develop a conceptual conventional solution that would address each need **c.** Quantify the conceptual cost of conventional upgrades **OUTPUT:** Establishes total cost used in avoided-cost calculation.
Step 2: Identify Timing and Duration of Need
a. Identify conditions in which the constraint is binding. **b.** Determine distribution of hours of need. **Output:** Define total hours of need
Step 3: Calculate Hourly Avoided Costs
a. Hourly avoided costs = (Total Cost of Upgrade) / (Total hours of need) **b.** Produce an hourly avoided cost for any solution to meet the identified need **OUTPUT:** Avoided cost curve for comparing ATT and non-wire alternatives
Step 4: Screen ATT Candidates Against System Needs
Screen based on: + Technical fit and need-by date + Compatibility with RTO modeling and operations + Ability to reduce hours of binding constraint **OUTPUT:** List of viable ATTs to meet need
Step 5: ATT Benefit-Cost Assessment Using Avoided Costs
a. Quantify ATT solution cost

b. Estimate ATT effectiveness in reducing hours of need
c. Calculate ATT Avoided-Cost Benefits = Avoided Cost ($/hour) x Magnitude and Hours of Need Relieved
   + Where ATT only partially mitigates the constraint, benefits should be proportionally scaled.
d. Add Additional Monetizable ATT Benefits (if applicable)
   + If an ATT produces incremental benefits outside of binding hours such as congestion relief, curtailment reduction, deferral of additional conventional upgrades
e. Compare ATT Benefits to ATT Costs
   + Identify whether an ATT may provide equal or greater
   + cost-effectiveness than conventional project
f. Determine ability for ATT to fully or partially defer conventional project
g. Select the most cost-effective solution or portfolio of solutions

FINAL OUTPUT: Identifies the most cost-effective and reliable alternative using an avoided-cost framework

In future cycles, this framework can be used to (1) identify future transmission system needs and use cases that may present high-value opportunities for deployment of ATTs and NWAs, and (2) over time, incorporate high-level cost and potential estimates to characterize the impacts of ATTs and NWAs within the IPF. This framework is intended to provide a consistent, transparent method for evaluating ATTs and NWAs as part of the overall suite of options available to meet Illinois' transmission needs while also allowing for incremental refinement as more data and experience become available.

Policy and Regulatory Context

The first step in evaluating the role of ATTs and NWAs in Illinois is understanding which actions ICC themselves can take and which require collaboration with other regulatory or planning authorities. Jurisdiction over transmission and distribution (T&D) planning in Illinois is split between federal and state regulatory bodies: FERC and ICC. FERC has oversight of transmission over 100kV, and ICC has oversight over distribution and siting and permitting of transmission. Two separate regional grid planning entities – MISO and PJM – carry out bulk grid planning and market operations in Illinois under FERC jurisdiction.

Federal

FERC oversees interstate transmission lines, wholesale markets, and regional grid planning efforts, which are carried out by RTOs – in the case of Illinois, MISO and PJM. Several FERC orders pertain to ATTs:

+ **FERC Order 1000,** issued in 2011, introduced a number of major reforms to transmission planning and cost allocation. The order required consideration of "non-transmission alternatives" during regional planning efforts, but critics at the time noted that FERC failed to address key barriers to their adoption, including a clear methodology for calculating their value and allocation of costs among beneficiaries. As a result, the order largely failed to spur adoption of these novel solutions.[111]
+ Passed in 2021, **FERC Order 881** was designed to facilitate more efficient use of the transmission system by requiring RTOs to evaluate near-term transmission service based on ambient-adjusted line

[111] *Elizabeth Watson and Ken Colburn, "Looking Beyond Transmission: FERC Order 1000 and the Case for Alternative Solutions," April 2013: https://www.raponline.org/knowledge-center/looking-beyond-transmission-ferc-order-1000-and-the-case-for-alternative-solutions/.*

ratings (i.e., DLRs). Although FERC did not mandate the use of DLRs, the order effectively required RTOs to develop systems and procedures that would allow transmission providers to adopt them if and when they choose.

- In addition to streamlining generator interconnection processes, **FERC Order 2023** requires transmission providers to evaluate certain ATTs during the cluster study process to determine whether they offer similar benefits as the proposed resources but in less time or at a lower cost. Specifically, the order mandates consideration of:
  - **static synchronous compensators:** power electronics devices that provide fast, dynamic voltage support and reactive power control
  - **static VAR compensators:** shunt-connected systems using reactors and capacitors to regulate reactive power and stabilize voltage
  - advanced power flow control devices: defined above
  - transmission switching (topology optimization): defined above
  - **synchronous condensers:** rotating machines that generate or absorb reactive power to maintain voltage stability and system inertia
  - **voltage source converters:** DC-AC conversion devices that enable controllable power transfer and integration of HVDC links or renewable generation
  - advanced conductors: defined above
  - **tower lifting:** a mechanical method of raising existing transmission structures to increase ground clearance and safely accommodate higher line ratings
- As part of a slew of reforms aimed at encouraging more proactive transmission planning, **FERC Orders 1920/1920-A/1920-B**, passed in 2024, require transmission providers to consider the use of ATTs when assessing future system needs. The order requires consideration of the following technologies in regional transmission planning and cost allocation processes, which must be conducted at a minimum every five years:
  - dynamic line ratings,
  - advanced power flow control devices,
  - advanced conductors, and/or
  - transmission switching

Together, these orders have set the stage for transmission providers in Illinois to consider ATTs during generator interconnection and long-term transmission planning processes. Both RTOs have already taken steps to comply with Order 2023, while the first compliance filing deadlines for Orders 1920 in 2025 and into 2026.[112] Notably, FERC's previous orders aimed at reforming planning processes largely avoid discussion of NWAs, which the FERC Commission historically viewed as distribution technologies outside of its jurisdiction. In all of its orders, FERC is careful to distinguish between transmission assets, which are compensated through regulated rates, and generation or storage assets, which typically participate in energy markets.

- The only major order pertaining to DERs, **FERC Order 2222**, was adopted in 2020. The order sought to remove barriers to the participation of DERs in energy, capacity, and ancillary services markets. FERC

[112] *FERC Order No. 1920 Compliance Filing Schedule (2025): https://www.ferc.gov/news-events/news/order-no-1920-compliance-filings-schedule.*

required RTOs to establish rules concerning the aggregation of DERs and directed them to coordinate with aggregators, distribution utilities, and local regulatory authorities on their dispatch. Although implementation has been inconsistent thus far, the order lays the groundwork for widespread adoption of VPPs.

RTO Processes and Planning Practices

Aside from the territories of municipal utilities and rural electric cooperatives, the rest of Illinois lies within MISO and PJM's planning jurisdiction. In response to the orders described above, both RTOs are taking steps to update their interconnection and planning processes to include ATTs, although implementation is ongoing. Stakeholders have also weighed in via workshops and compliance filings to push the RTOs for more transparency about how these novel technologies are factored into decision making.

PJM

In response to FERC's orders on ATTs, PJM developed a series of technical reference guides designed to support their future consideration in planning processes. The RTO also stated its support for the "transparent, cost-effective, efficient and reliable deployment" of ATTs, including advanced conductors, DLRs, APFCs, and TO. While ATTs can be proposed in PJM's competitive RTEP solicitations, most solutions that have been selected to date remain conventional transmission lines and upgrades. Furthermore, PJM has, thus far, declined to incorporate DLRs into their generator interconnection process, claiming the technology is not an adequate alternative to traditional network upgrades. [113] Nor has PJM established a standardized cost recovery mechanism tailored to ATTs, creating uncertainty around how developers or transmission owners would be compensated for deploying these solutions.

PJM and its member utilities have explored DLRs in a handful of successful pilot projects, but few examples exist of other ATTs. In 2016, PJM undertook a DLR pilot project in collaboration with AEP and technology company LineVision that reduced annual congestion payments by $4M at an upfront cost of $500k, representing a payback period of just two months. [114] PJM member Duquesne Light installed LineVision systems on two lines in a 2021 pilot, increasing capacity by 25% and prompting an expanded partnership between the two companies.[115] In Pennsylvania, PPL installed DLRs on three historically congested 230 kV lines, estimating that the project could save customers $23M annually in congestion costs.[116]

PJM recently revised its treatment of energy efficiency such that EE is no longer eligible to participate as a supply-side capacity resource in the RPM.[117] This change limits the extent to which EE can be considered a supply-side solution within PJM's planning and market processes, even though it may continue to provide local demand-side benefits within Illinois. At the same time, Illinois with other states through OPSI have highlighted the opportunity for greater transparency about how PJM models demand response and price-response demand in its capacity market. Evaluating DR and demand-side resources as part of its long-term transmission planning and market design may reveal opportunities where the locational value of NWAs can be evaluated alongside traditional transmission solutions.

[113] PJM Grid Optimization Solutions: https://www.pjm.com/about-pjm/advanced-technologies/grid-optimization-solutions.
[114] PJM's Advanced Technology Initiative (2023): https://www.pjm.com/-/media/DotCom/about-pjm/exploring-tomorrows-grid/advanced-tech.pdf.
[115] LineVision (2022): https://www.linevisioninc.com/news/duquesne-light-company-further-enhances-transmission-capacity-reliability-with-grid-enhancing-technology.
[116] PJM Inside Lines (2022): https://insidelines.pjm.com/dynamic-line-rating-activated-by-ppl-electric-utilities/.
[117] Comments of the Independent Market Monitor for PJM before FERC (2024): https://www.monitoringanalytics.com/filings/2024/IMM_Comments_re_PJM_EE_Filing_Docket_No_ER24-2995_20240927.pdf?utm.

MISO

Similar to PJM, although MISO has taken steps to fulfill the requirements of recent FERC orders, inclusion of ATTs into formal planning frameworks remains limited. The 2024 MTEP explicitly addressed the potential for ATTs to address transmission needs identified in Tranche 2.1 of the Long-Range Transmission Plan (LRTP), but the RTO ultimately found that the "necessary line mileages and power transfer requirements suggested that a 765 kV backbone would be the optimal choice at this stage," whereas ATTs were better suited to solving local issues.

Historically, the MISO Transmission Expansion Plan (MTEP) process has relied on large-scale transmission portfolios, with ATTs only considered as supplemental tools. In recent years, however, MISO has implemented solutions using promising technologies, such as topology optimization. Under MISO's "economic reconfiguration" process, market participants or third-party vendors may propose specific network reconfigurations, such as temporary line openings, bus splits, or alternative switching schemes, designed to reduce congestion on binding flowgates. MISO evaluates these proposals for feasibility and reliability impacts and then coordinates with the affected transmission owners, who must consent before any reconfiguration is implemented.

A notable example was documented by the Energy Systems Integration Group in 2024. During a planned outage affecting the Split Colby 161-kV facilities, congestion costs were projected to exceed $30 million over six weeks. Following a proposed topology reconfiguration, MISO implemented an alternative switching arrangement that rerouted flows away from the constrained facility. After-the-fact analysis showed that congestion costs fell to approximately $6 million for that period, an estimated $24 million in customer savings, representing more than an 80% reduction in congestion during the outage window.[118] This case is illustrative of how topology optimization can mitigate short-duration, recurring constraints at relatively low cost compared to capital-intensive upgrades.

Beyond Topology Optimization, MISO has also taken steps to incorporate Storage as a Transmission-Only Asset (SATOA) into the MTEP process, though adoption has been slow.[119] Few SATOA projects have advanced beyond the conceptual stage, owing to modeling complexities and the relative nascency of storage-based transmission solutions in the region. MISO has also updated accreditation and processes for load modifying resources (like DR and EE) to improve measurement and verification to increase confidence that resources will be available in emergencies.[120]

State

As the state's public utility regulator, ICC is primarily responsible for regulating the distribution system. Therefore, efforts to implement ATTs on high-voltage lines within the state will require ICC to operate within the framework established by FERC and carried out by the RTOs. Implementation of NWAs that interconnect at lower voltages, such as distributed generation or storage, falls more squarely within ICC's authority,

---

[118] *Utility Perspectives on Making Grid-Enhancing Technologies Work (ESIG 2025): https://www.esig.energy/wp-content/uploads/2025/07/ESIG-Grid-Enhancing-Technologies-report-2025.pdf.*
[119] *MISO Storage as Transmission-Only Asset (2022): https://www.misoenergy.org/engage/MISO-Dashboard/storage-as-transmission-only-asset/.*
[120] *MISO LMR Enhancements (August 20, 2025): https://cdn.misoenergy.org/20250820%20RASC%20Item%2008b%20LMR%20Enhancements%20Near%20Term%20Filings%20(RASC-2019-9)713763.pdf.*

although these solutions are not as well suited to addressing targeted transmission needs that are the subject of this report.

CEJA requires Illinois utilities to develop Long-Term Distribution System Investment Plans that consider whether "non-traditional, grid-related technologies" facilitate the deferral or replacement of planned investments in the transmission and distribution system. The law explicitly mentions DERs, NWAs, flexible or controllable load, and beneficial electrification. For its part, ICC is tasked with establishing rules for the sourcing of non-traditional solutions like NWAs and commissioning the Report on the Value of, and Compensation for, DERs, which was published in January 2025.[121]

Summary of RTO and State Planning Processes for ATTs and NWAs

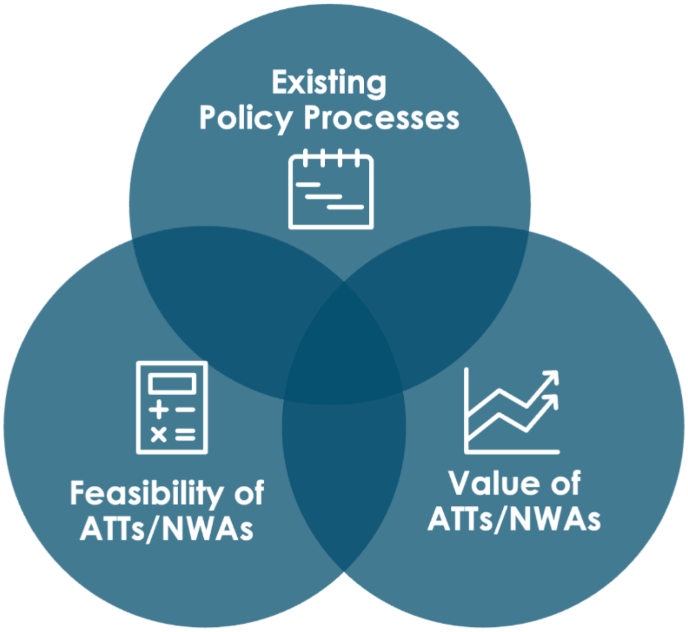
While the Commission does not have jurisdiction over regional transmission planning, federal policy has established clear expectations for transmission providers to consider ATTs within their planning and interconnection processes. Within this framework, the ICC plays an active coordinating role by engaging with transmission owners and regional operators to ensure these evaluations reflect Illinois' policy priorities and system needs. The ICC also has more direct authority over NWAs at the distribution level, where state regulation can guide how such solutions are implemented and valued. However, these approaches generally have more limited ability to address bulk transmission needs, which remain the primary focus of this REAP.

Findings

ATTs and NWAs should be evaluated based on both their ability to (1) meet transmission system needs and (2) provide value to ratepayers. The current state of RTO planning processes places more emphasis on identifying system needs and evaluating proposed solutions than allowing market participants to propose use cases of technologies like ATTs or NWAs that create value for stakeholders. In the following Figure 38, the current approach is best characterized as identifying the overlap between existing policy processes, the feasibility of ATTs or NWAs, ideally where these technologies also create value. However, there remain opportunities for deployment where feasibility and value overlap outside of existing policy processes.

[121] Climate and Equitable Jobs Act, Public Act 102-0662 (2021): https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/ceja/documents/102-0662.pdf.

Figure 38: Framework for Expanding ATT Consideration



Under the right circumstances, ATTs and NWAs may be able to alleviate costs and address issues faster than other options, enabling renewable integration, congestion relief, and load growth and electrification and increasing resiliency to extreme weather events. Table 12, below, summarizes the relative value and readiness of ATTs and NWAs for Illinois. These examples are not exhaustive but illustrate where each technology can most effectively address REAP-identified needs. Their ultimate applicability depends on network topology, regulatory treatment, and the evolving seasonal load profile across the state.

Table 12: Summary of ATT and NWA Findings for REAP Needs

Technology	Relevant Value Stream(s)	Readiness	Comments
Dynamic Line Ratings (DLR)	Congestion relief, increased utilization, winter reliability	High	Effective during cold, windy conditions when transmission limits are binding; depends on data and communications infrastructure.
Advanced Power Flow Controllers (APFCs)	Congestion relief, operational flexibility	Medium	Best for meshed networks; limited benefit in rural or radial zones common in some REAP zones.
Topology Optimization	Congestion relief, system flexibility	Medium	MISO has begun deploying case-specific reconfigurations with demonstrated savings; value grows with increased system visibility.
Advanced Conductors	Capacity expansion, siting avoidance, load-growth support	High	Strong fit where permitting new lines is difficult; reconductoring existing structures can unlock headroom for renewables.

Storage as Transmission-Only Asset (SATOA)	Reliability, congestion management, bridge for long-lead time projects	Low–Medium	Concept proven but few deployments; value depends on regulatory clarity and ability to stack transmission and market services.
Distributed Energy Resources (DERs)	Local congestion relief, T&D deferral, reliability support	High	Can provide specific locational benefits to mitigate a system constraint; requires high penetration and tight operational coordination with RTO.
Demand Response (DR)	Peak load reduction, load shifting, emergency reliability support	Medium - High	Suited to mitigating localized or system peak conditions; effectiveness depends on enrollment, automation, and participant performance; stronger potential to bridge near-term needs rather than permanently avoiding large transmission projects.
Virtual Power Plants (VPPs)	Aggregated grid services (peak reduction, load shifting, ancillary services), localized congestion relief	Medium	Strong fit in zones with high DER penetration and enabling aggregation rules; can defer smaller upgrades and complement transmission where telemetry, dispatch visibility, and locational compensation are in place; complexity of coordination and settlement across utility/RTO boundaries remains a barrier.
Energy Efficiency (EE)	Long-term load reduction, local capacity deferral	High	Can reduce peak demand and defer some local upgrades. Savings are not dispatchable and can be hard to target specific constraints.

Although RTOs have already started to incorporate ATTs and NWAs into long-term planning and regional markets, several areas for improvement remain. Both MISO and PJM now allow for proposal of ATTs in their respective transmission planning processes, but there does not appear to be a standardized methodology for evaluating the reliability contribution of these technologies, nor has either RTO shared comprehensive guidance on cost recovery. Furthermore, in situations where no specific "need" has been identified as part of a formal RTO proceeding, market participants have few opportunities to propose ATTs or NWAs where their implementation may still create value. The notable exception to this rule is MISO's Economic Reconfiguration process, which allows market participants to propose a congestion solution for evaluation by transmission owners on the basis of both reliability and economic impact. The learnings from this program, which has already generated meaningful savings for ratepayers, should be applied to other alternative solutions as well.

Recommendations

ATTs

As a first step, the ICC can encourage Illinois utilities to further explore use cases for ATTs in the context of REAP needs. For example, the ICC could direct Ameren and ComEd to identify reconductoring opportunities that would facilitate the integration of new renewables in a cost-effective manner. One potential compliance mechanism would be to require annual or biannual reports on any opportunities the utilities have identified for ATTs on their systems. In the event such an opportunity arises, the ICC could also support the utilities with their proposals to the RTOs.

In future REAP cycles, the ICC should explore ways to quantify the cost of ATTs and look for ways to model their potential benefits as part of the IPF. ATTs should be compared against their conventional alternatives to ensure the proposed solution yields savings for ratepayers while adequately addressing the identified system need and also consider implementation timeline. In addition to rigorously quantifying ratepayer savings, which must include the value of deferred investments in expensive new infrastructure, ICC should also account for the cost of any complementary investments in information technology systems, operational protocols, and workforce training.

The ICC should continue to engage with the RTOs as they incorporate ATTs into their planning processes for compliance with various FERC Orders. Staff can advocate for uniform methodologies to quantify ATTs' reliability value and for predictable cost-recovery pathways that give developers confidence to pursue deployment of these technologies. Finally, the ICC can encourage the RTOs to look at ways to build on learnings from MISO's Economic Reconfiguration initiative, which provides a structured pathway for stakeholders to identify low-cost, value-adding ATT opportunities that can deliver meaningful near-term system benefits. The process allows market participants to submit ideas for both existing and anticipated constraints, subject to clear data requirements and screening criteria, followed by standardized reliability and market evaluations. This type of process provides opportunities for deployment of ATTs and NWAs, even in a process in which conventional solutions are not being explored.

NWAs

In future REAP cycles, the ICC should continue using the IPF to explore where DERs, flexible load, and other NWAs may provide locational value. The REAP's role is to identify relatively broad zones for renewable development and needed transmission upgrades, including where local non-wires solutions could mitigate constraints. This information can guide, but not replace, more detailed resource planning in other processes. The ICC should continue advocating for MISO and PJM to explicitly account for the locational value of DERs in transmission planning, especially as RTOs implement Order 1920 and integrate non-transmission alternatives into their long-term planning processes. REAP findings on where constraints arise and where flexible resources could complement transmission can support ICC advocacy for RTO methodologies that better reflect how DERs reduce congestion, avoid curtailment, or moderate local upgrade needs. In parallel, this information might help the IPA tailor procurement programs (including forthcoming storage procurements) to encourage DER and storage deployment in high-value locations, enabling the state to use all available tools to address transmission system needs identified by the REAP.

Beyond the immediate scope of the REAP, the ICC should continue its work on DER valuation and compensation, building on the State's 2025 Value of DER study. Clearer price signals and program design can help translate REAP-identified needs into a cost-effective deployment of a portfolio of solutions that support reliability, reduce congestion, and complement long –lead-time transmission development.

Strategic Element 5: Leveraging Regional Processes and Markets

Strategic Element 5, *Leveraging Regional Processes and Markets*, examines how Illinois can advance its clean energy and reliability objectives by engaging with and influencing the regional transmission planning and market structures of MISO and PJM. This chapter defines the policy and regulatory pathways available for the ICC to ensure that REAP-identified transmission needs are recognized, studied, and ultimately advanced through regional processes. This chapter begins by summarizing lessons from the 2024 REAP and describing how RTO market rules and transmission planning frameworks interact with Illinois' policy targets. The chapter then explores the range of regulatory pathways, from established reliability planning to emerging pathways under FERC Orders 1920, 1920-A, and 1920-B, through which Illinois can pursue projects that align with state policy. Finally, Strategic Element 5 assesses how proactive transmission planning can support faster interconnection of clean resources and how policy tools such as greenhouse gas (GHG) border pricing could mitigate emissions leakage as fossil generation retires. Collectively, these sections discuss how Illinois can use its participation in regional markets and planning forums to translate the needs identified in the REAP into actionable transmission development and long-term policy alignment.

Highlights from the 2024 REAP

Aligning Market Design with Illinois Policy Goals

Strategic Element 5 of the 2024 REAP focused on aligning regional market structures with Illinois' policy-driven goal to transition to a 100% clean energy mix. The report observed that existing MISO and PJM market designs require improvement to fully support long-term reliability under a changing system, including a decarbonizing grid. In the 2024 REAP, ICC emphasized that Illinois' reliance on these regional markets necessitates active engagement to ensure that capacity, energy, and ancillary service market constructs evolve in a way that enables Illinois policy goals to be achieved cost-effectively.

The 2024 REAP identified several areas where reforms were underway or warranted continued engagement. In the MISO region, the report highlighted the results of MISO's 2022-2023 Planning Resource Auction, where Zone 4 experienced a capacity shortfall, indicating a reliability concern. The report recommended near-term measures such as demand response, energy efficiency, and forward capacity procurement to help maintain reliability. In PJM, the REAP underscored the need to modernize the capacity market so that procurement volumes and resource accreditation better align with reliability needs and Illinois' clean-energy policies. Across both RTOs, the report encouraged Illinois to advocate for market products that recognize the reliability and policy value of clean resources, including storage and demand-side solutions.

Advancing Regional Coordination and Clean Attribute Markets

The 2024 REAP also discussed the importance of improving coordination between Illinois' clean energy policies and emerging regional market mechanisms for tracking and trading clean energy attributes. It highlighted the ICC's active participation in the Organization of PJM States, Inc. (OPSI) and PJM's Clean

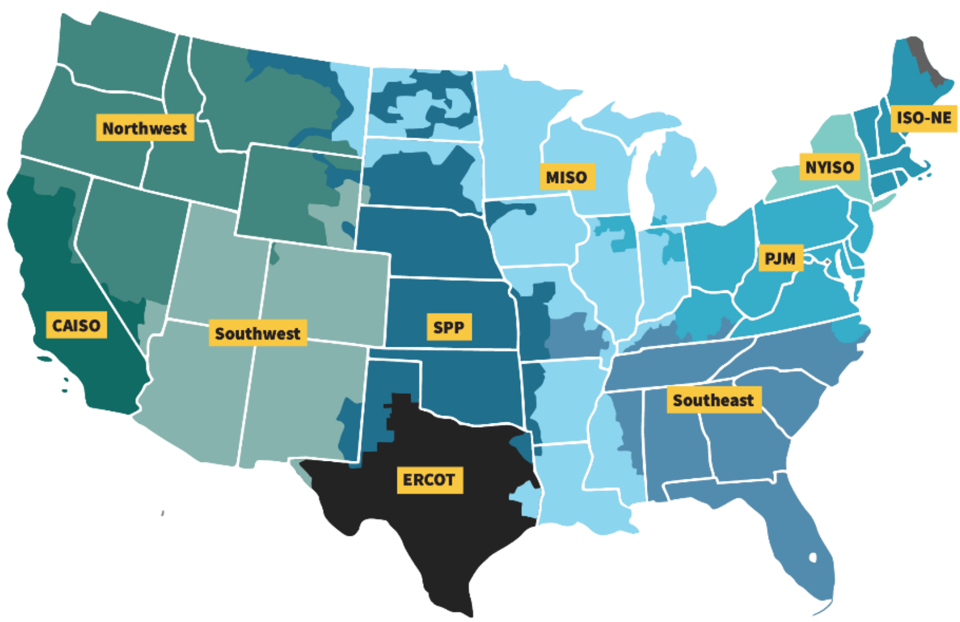
Attribute Procurement Senior Task Force,[122] which are exploring frameworks for region-wide markets for renewable and clean energy credits. The REAP suggested that such mechanisms could eventually complement the IPA's RPS by providing new pathways for Illinois consumers and utilities to procure verified clean attributes and to participate in cross-border clean energy trade.

The 2024 REAP also recommended that Illinois continue to collaborate with neighboring states and regional entities to manage greenhouse gas emissions and prevent emissions "leakage" as fossil generation retires. This included advocating for enhanced greenhouse gas accounting within RTO operations and supporting the development of market-based tools to track emissions embedded in imports and exports. These efforts were framed as part of a longer-term strategy to align regional market incentives, reliability frameworks, and emissions accounting with Illinois' clean energy transition.

Regional Transmission Organizations Roles in Planning

Similar to the previous REAP, this report highlights the role of RTOs in achieving REAP aims. As such, it is important to situate the REAP within the context of the RTOs' role in transmission planning and markets. RTOs, such as MISO and PJM, are the framework for wholesale electricity markets and system planning across most of the Eastern Interconnection. They are responsible for ensuring that the transmission network operates reliably and efficiently, while maintaining open access to generation and load across multiple states. Both RTOs develop plans to ensure the economic and reliable operations of their transmission systems, operate centralized markets for energy, capacity, and ancillary services, and they administer interconnection processes that determine how new resources connect to the grid. Figure 39, below, shows the US map of RTOs and Independent System Operators, and shows how Illinois is divided between MISO and PJM.

Figure 39: Map of US Regional Transmission Organizations and Independent System Operators



Source: FERC

[122] *Since the 2024 REAP, PJM no longer facilitates the PJM Clean Attribute Procurement Senior Task Force. Discussions have shifted into OPSI.*

MISO and PJM develop regional transmission expansion plans that help ensure system reliability and try to capture economic efficiency across their multi-state footprints. These plans assess system needs, evaluate solutions, and identify projects to relieve congestion or meet state and federal reliability standards. As discussed in further detail in this chapter, transmission planning within both RTOs may incorporate public policy drivers, but the extent and form of that integration differ between RTOs, and the degree to which such considerations translate into specific transmission projects varies accordingly. For Illinois, these RTO planning frameworks shape how power is delivered reliably to consumers, impact costs of electricity bills. and serve as key tools for identifying the new lines or upgrades needed to support achievement of the state's policy targets. Realizing that potential will depend on continued engagement and advocacy within the RTO processes.

Mapping Illinois' Policy Targets to RTO Market Roles

CEJA sets a 50% RPS by 2040 and a full phase-out of emissions from large fossil generation by 2045. Achieving these targets will require coordination and advocacy at MISO and PJM, not only to plan the transmission infrastructure needed for renewable expansion but also to ensure that regional market rules and emissions accounting mechanisms align with Illinois' policy trajectory. As emphasized in the 2024 REAP, transmission is critical for meeting Illinois' clean-energy goals, and transmission investments should anticipate, not react to, future renewable build-out and retirements. Additionally, as fossil generation in Illinois retires, it is possible that Illinois will increase its reliance on imported electricity, resulting in emission "leakage". In the 2024 REAP Order, the Commission acknowledged the risk of GHG leakage and directed Staff to explore the topic in future REAP cycles. This is discussed later in this Chapter.

Transmission planning in Illinois operates across two overlapping but distinct jurisdictions: state jurisdiction (ICC) and RTO jurisdiction (MISO and PJM). The ICC has authority over transmission siting within the state, particularly to ensure that transmission projects serve Illinois consumers reliably, affordably, and are in alignment with state policy goals. However, for projects generally operating at 100 kV and above, planning and cost allocation generally fall under the authority of the RTOs, which plan, evaluate, and approve transmission projects that affect regional reliability or market operations. Because Illinois participates in both RTOs, most large-scale transmission development that could enable CEJA's clean-energy targets must pass through those regional RTO processes. While the RTOs have control over much of transmission planning in Illinois, the ICC influences these regional processes through participation in RTO stakeholder committees, filings at FERC, and engagement in the regional state committees, OPSI and OMS.

This REAP emphasizes RTO transmission planning when considering viable pathways to develop solutions for REAP zone needs, recognizing that state policy priorities cannot be achieved without active participation and advocacy within those regional forums. This chapter first examines how Illinois can align transmission and interconnection processes to support renewable generation and then turns to an additional challenge of managing emissions leakage as in-state fossil generation retires, including a discussion of potential solutions such as GHG border pricing.

Regulatory Pathways for Transmission Needs

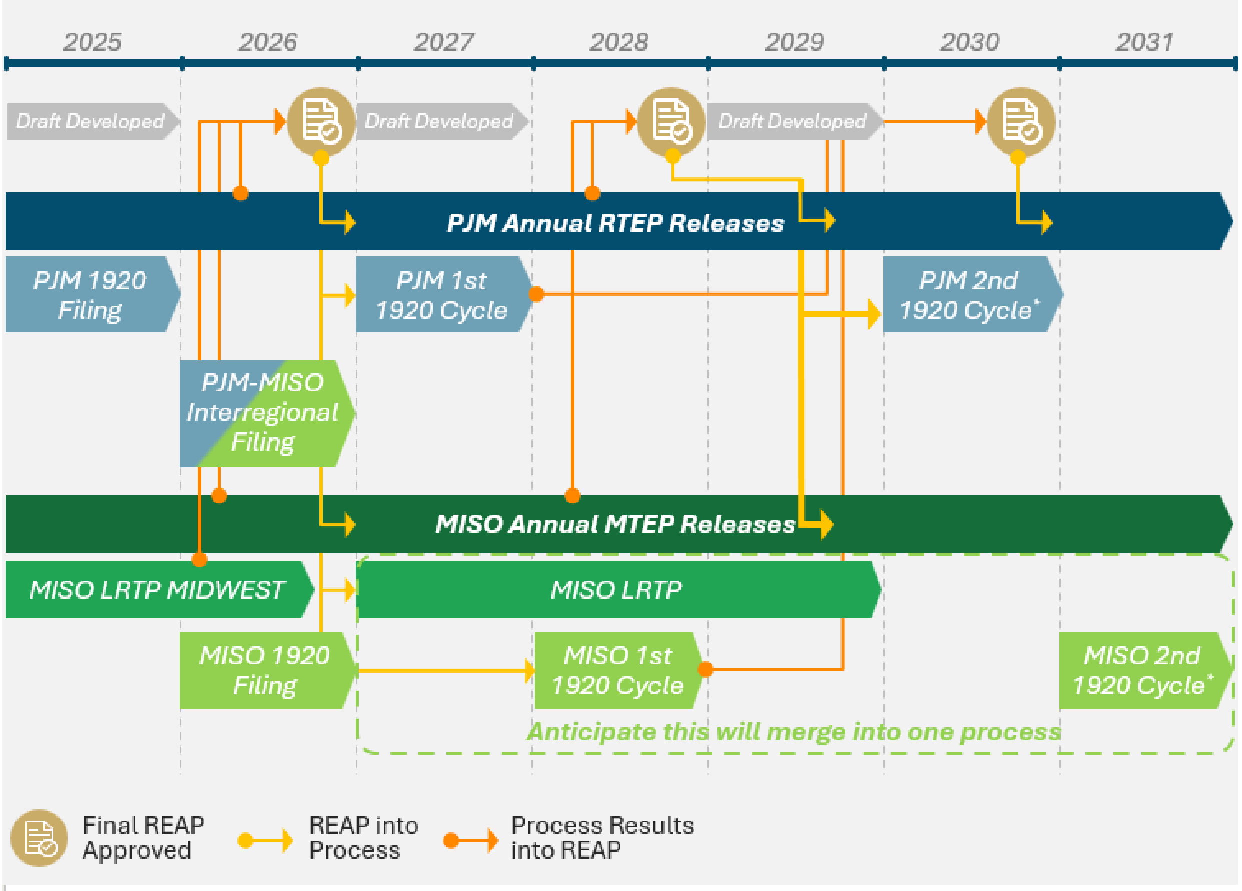
As Illinois advances its clean energy goals, transmission development will depend on effectively navigating the planning frameworks of both MISO and PJM. Given Illinois' participation in two RTOs with distinct planning processes, cost allocation frameworks, and policy integration mechanisms, understanding the available pathways for transmission development is foundational. The REAP does not directly authorize or select transmission projects; instead, it identifies transmission system needs expected to arise in Illinois as the state progresses towards its policy targets and discusses opportunities for the ICC to influence and align regional transmission planning to address these needs. The ICC's engagement in these RTO processes will be critical to ensure that REAP-identified transmission needs are recognized within the planning mechanisms that determine how benefits are determined, which projects advance, and how costs are shared.

This section provides an overview of the major planning processes and investment categories available in MISO and PJM, highlighting where the REAP can most effectively intersect with each. It focuses on how the ICC can use established and emerging RTO processes to advance transmission projects that unlock and/or support renewable development in the REAP zones.

Pathways Available for Transmission Development in Each Region

This REAP report has the opportunity to influence multiple MISO and PJM planning efforts, including both the annual transmission planning cycles and the new FERC Order 1920 planning cycles. These planning cycles, in return, will influence the development of subsequent REAP reports. Figure 40 illustrates the major planning processes and associated events in MISO and PJM with respect to the REAP timelines.

Figure 40: Timeline of how REAP Reports will Feed into RTO Processes



*This is the earliest they could begin the second planning cycle. Will depend on their proposed framework.

This timeline illustrates the iterative relationship between the REAP and the RTO planning cycles. Once finalized, the REAP will inform ongoing and upcoming MISO and PJM planning processes, including annual updates such as the RTEP and MTEP, as well as multi-year and scenario-based planning efforts under FERC Order 1920. Because these processes operate on staggered timelines, REAP findings will be integrated into different regional planning efforts at different times. In turn, as MISO and PJM complete their Order 1920 filings, long-term planning cycles, and identify annual reliability and economic projects, those results will feed back into subsequent REAP updates. This dynamic underscores the need for the ICC and stakeholders to maintain both annual engagement and multi-year coordination. On an annual basis, ICC and stakeholders will need to assess the overlap between REAP needs and near-term reliability and economic planning outcomes. It will also be important for ICC and stakeholders to engage in multi-year coordination to ensure that long-term transmission plans reflect Illinois' clean-energy policy objectives and the evolving REAP framework.

Overview of PJM Regulatory Pathways for Transmission Development

The PJM RTEP establishes the regulatory framework for identifying and approving transmission projects needed to maintain reliability and improve market efficiency. The RTEP process includes several project categories, each with distinct purposes and cost-allocation methods. The following describes the pathways available within PJM's planning framework to ground exploration of available pathways for REAP needs. RTEP projects can be categorized into:

+ **Baseline Reliability Projects** are projects intended to ensure compliance with utility and NERC reliability standards and may be required to ensure market efficiency criteria, public policy needs, or operational requirements. These projects are typically open to competitive solution bidding, but under some circumstances (e.g., an immediate need with insufficient time for a proposal window), PJM may directly assign to the governing transmission owner (TO). For projects that cost more than $5M, 50% of the cost is allocated via load-ratio share and 50% is allocated to the specific zones that benefit using PJM's DFAX (distribution factor) analysis.[123]
+ **State Agreement Approach** projects are a pathway for a state or multiple states to propose a transmission project for inclusion in the RTEP that advances the state's public policy goals if the state/s agree/s to assume the cost of the project's build-out.
+ **Market Efficiency Projects** are transmission upgrades selected to reduce congestion when their projected economic benefits outweigh costs. PJM identifies these projects through competitive proposal windows using a benefit-cost threshold of 1.25:1, based on modeled energy and capacity savings. Approved projects are included in the RTEP. Larger projects' (over $20M) costs are allocated proportionally to zonal benefits, and smaller projects typically are allocated to a local zone, unless the benefits accrue elsewhere.[124]
+ **Network Projects** permit the interconnection of a new service request, including new generators, merchant transmission, and new loads. These projects are typically allocated to the governing TO under the conditions agreed upon in the Interconnection Service Agreement.
+ **Supplemental Projects** are planned, developed, and funded by transmission owners to meet local reliability and asset condition needs and costs are allocated amongst the transmission owner's customers; therefore, they are exempt from the PJM competitive bidding process and are not subject to PJM board review.

---

[123] *PJM Manual 14B: PJM Region Transmission Planning Process (September 25, 2024): https://www.pjm.com/-/media/DotCom/documents/manuals/m14b.pdf.*
[124] *Ibid.*

Figure 41: PJM Cumulative Investment in Transmission via Planning Pathways

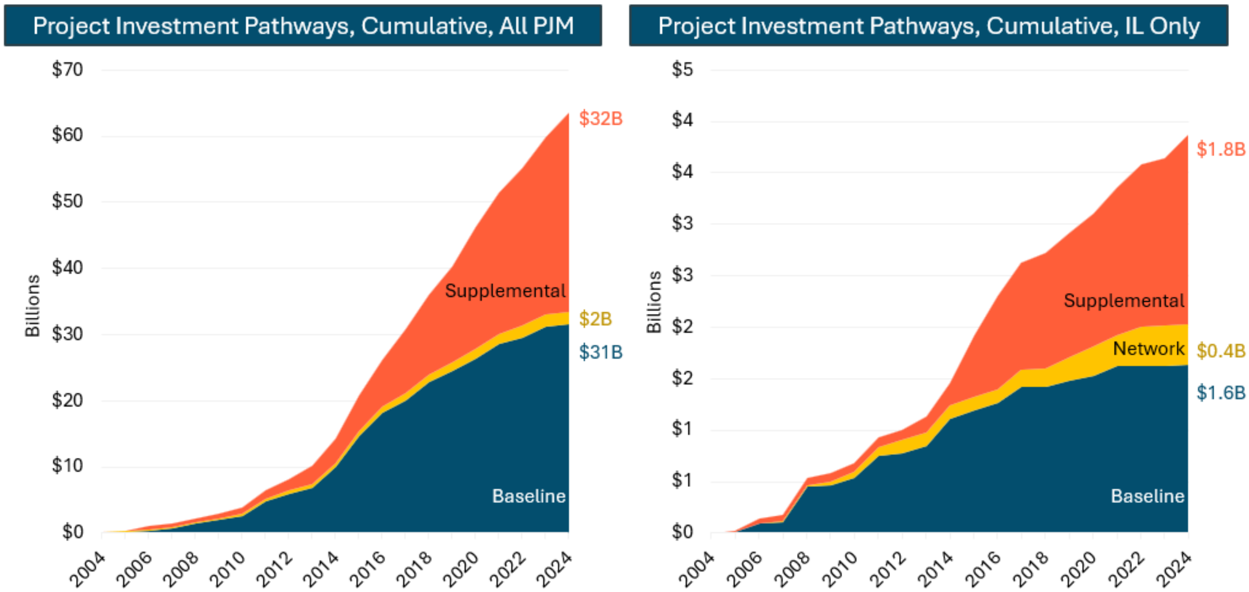


Figure 41, above, illustrates the cumulative cost of transmission investments approved through PJM's various planning pathways from 2004 through 2024. Over this period, the total investment was approximately $65 billion worth of projects. Baseline projects have historically been the largest category of transmission investment in both PJM as a whole and PJM territory in Illinois specifically, where baseline projects totaled $1.6 billion. Supplemental projects have recently grown to be the largest slice of both PJM wide and Illinois specific projects, comprising $1.8 billion of Illinois transmission investment. Baseline project costs are socialized across those benefiting regions, relieving any one state or TO from shouldering the full project cost. In contrast, the local transmission territory bears the full cost of Supplemental projects.

Overview of MISO Regulatory Pathways for Transmission Development

The MTEP outlines the procedures used to evaluate and approve transmission projects that address regional reliability, economic efficiency, and policy-driven needs. The MTEP process encompasses multiple project categories, including those that support long-term planning through the Long-Range Transmission Planning (LRTP) initiative. This section summarizes the regulatory pathways available within MISO's planning framework that may provide opportunities for transmission development consistent with REAP objectives. Common project types identified through MISO's planning processes include:

- **Baseline Reliability Projects** are transmission upgrades required to maintain compliance with NERC reliability standards and MISO planning criteria, including those identified to address system reliability violations or local transmission issues. These projects are generally assigned to the local transmission owner through MISO's Transmission Expansion Plan (MTEP) process and are cost-allocated to the transmission pricing zone(s) that benefit from the project, as determined through MISO's reliability impact analysis.
- **Generator Interconnection Projects** are upgrades necessary to accommodate new or modified generation or transmission interconnection requests. These projects are identified through MISO's Generator Interconnection Queue studies and cost-allocated according to the generator

interconnection procedures and typically participant-funded by the interconnection customer under the Generator Interconnection Agreement (GIA).

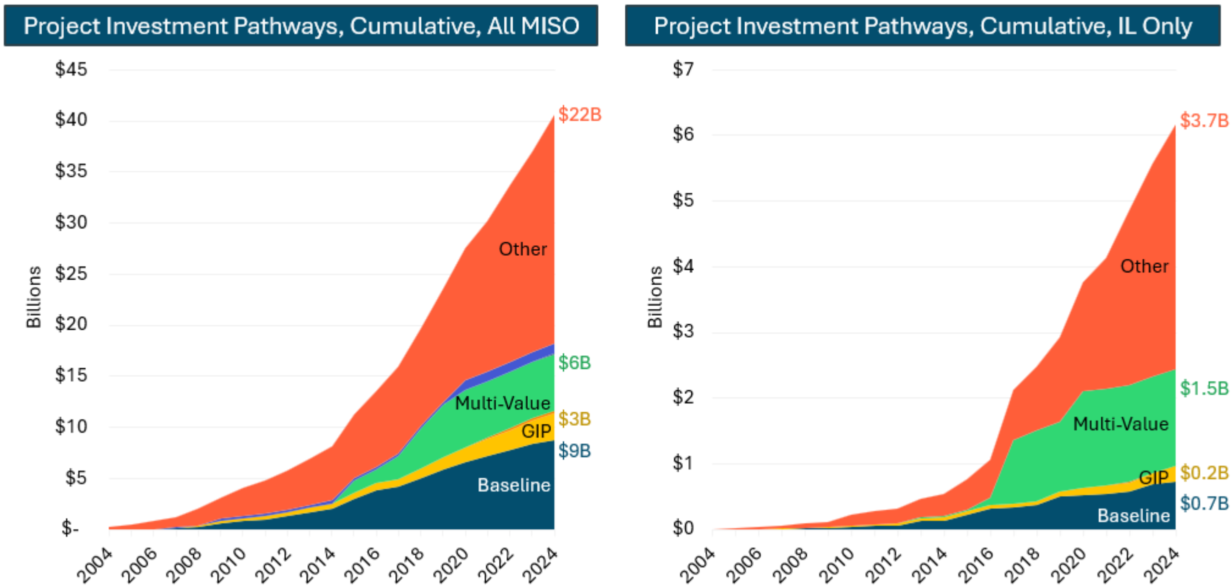
- **Market Efficiency Projects** are regional transmission upgrades designed to reduce congestion on the transmission system when their expected economic benefits exceed project costs by at least 1.25:1. MISO identifies these projects through periodic competitive planning cycles that evaluate reductions in production costs and congestion across pricing zones. The costs of approved Market Efficiency Projects are allocated to benefiting zones in proportion to measured production cost savings.
- **Multi-Value Projects (MVPs)** provide widespread regional reliability, economic, and public policy benefits. MVPs are approved by the MISO Board. The costs of MVPs are shared across all MISO load or on a sub-regional basis, dependent on project benefits.
- **Other Projects** include transmission upgrades that address localized needs, such as asset condition replacements, local reliability issues, or small-scale economic enhancements that do not meet the criteria of other project categories. These projects are typically proposed and funded by the local transmission owner and cost-allocated within the local pricing zone.

Included in the Multi-Value Projects category is the Long-Range Transmission Planning (LRTP) project set. These projects are a distinct set of projects designed to meet MISO's transmission needs 20-years into the future. These projects are approved in a series of groups released every several years[125] and are based on a series of planning "futures" comprising multiple scenarios describing possible public policy, reliability, and economic drivers and needs. This is an innovative departure from the historical method of planning to resolve only known short-term transmission needs by supplementing the traditional by-need tactic with a broader regional scenario-based optimization approach. Futures Series 1A was released in 2023 and informed LRTP Tranche 2.1 projects.

Figure 42 illustrates the cumulative cost of transmission investments approved through MISO's various project pathways from 2004 through 2024. Over this period, total investment has exceeded $40 billion. The "Other" category, which includes local reliability and asset condition projects, accounts for the largest share of total investment, highlighting the predominance of transmission owner driven upgrades. In contrast, regionally planned projects such as Baseline Reliability, Generator Interconnection, and Multi-Value Projects (MVPs) represent a smaller, but growing, portion of total investment, particularly since 2011 with the launch of the MVP portfolio and, more recently, the LRTP initiative. Illinois-specific investments total roughly $6 billion, including $3.7 billion in "Other" projects and $1.5 billion in MVPs.

[125] *In practice, since LTRP was initiated, MISO has released groups of projects every few years. There is nothing in MISO's planning practices that require this cadence.*

Figure 42: MISO Cumulative Investment in Transmission via Planning Pathways



Emerging Pathways for Transmission Development

FERC Orders 1920, 1920-A and 1920-B establish new long-term, scenario-based transmission planning requirements that identify and evaluate future system needs. These reforms move beyond short-term, reliability-driven planning to require a more forward-looking assessment of economic, reliability, and policy drivers over multiple decades. As MISO and PJM implement these new frameworks, they will create new pathways for states like Illinois to engage in regional transmission planning processes that explicitly consider state policy objectives. The magnitude of this change will vary by region. For MISO, the shift will likely be incremental given its existing LRTP framework, while for PJM, it represents a more significant transition toward proactive, scenario-based planning.

In 2024, FERC issued Orders 1920 and 1920-A to remedy deficiencies in the existing transmission planning requirements. The orders established five overarching requirements for transmission providers:

1. Conduct **long-term scenario-based regional transmission planning,** identifying future transmission needs and evaluating solutions with a transparent seven-factor benefits methodology.
2. Create one or more **default cost allocation methods** that will apply to the long-term regional transmission facilities.
3. **Consider a suite of alternative grid enhancing technologies to** identify efficient and cost-effective solutions to meet transmission needs.
4. Conduct local transmission planning to address local needs on their transmission system in a transparent and accessible process.
5. Modify existing **interregional transmission coordination** procedures to align with the long-term planning reforms.

Per Order 1920-A, transmission planners must, at minimum, incorporate the following factors to forecast the long-term landscape:

1. Federal, state, local, and federally recognized Tribal laws affecting resource mix and demand
2. Federal, state, local, and federally recognized Tribal laws on decarbonization and electrification
3. State-approved utility integrated resource plans and load-serving entities' expected supply obligations

Order 1920-A amended that transmission providers have some flexibility in how they assess the following four factors in scenarios:

4. Trends in fuel costs and in the cost, performance, and availability of generation, electric storage resources, and building and transportation electrification technologies
5. Generator retirements
6. Generator interconnection requests and withdrawals
7. Utility and corporate commitments and federal, state, local, or federally recognized Tribal policy goals that affect long-term transmission needs

Order No. 1920-A also clarified that transmission providers must consult with relevant state entities regarding how to incorporate state policies into scenarios.

In complying with Orders 1920, 1920-A, and 1920-B , MISO and PJM will be required to incorporate Illinois' state laws and policies into their planning scenarios, including 22 ILCS 5/8-512, the statutory foundation for REAP, meaning the scenarios should include considerations consistent with the goals of the REAP. The RTOs are also required to consult with relevant state entities on incorporating state policies into these scenarios, providing the ICC a forum to advocate for inclusion of REAP zones in scenarios.

Furthermore, Order 1920-A established that if relevant state entities request additional scenarios to inform their consideration of cost allocation methods and/or state agreement processes, transmission providers must develop a reasonable number of additional scenarios. The ICC can leverage this provision of Order 1920-A to have MISO and PJM study the potential benefits of the REAP identified transmission projects and associated cost allocation methods, potentially highlighting their value for creating headroom to benefit interconnecting resources.

Order 1920 also requires that states have the opportunity to identify and select transmission needs not selected by the RTO, similar to the PJM State Agreement Approach. This may provide another avenue for supporting REAP zones. As discussed further in the recommendations section, this approach may require additional advocacy at the RTO to ensure costs are socialized regionally when appropriate.

This REAP is being developed in advance of MISO and PJM finalizing their compliance frameworks under FERC Order 1920, which means this report precedes the release of key details about how each region will implement the new long-term planning requirements. While the compliance filings will ultimately determine the procedural and analytical pathways for integrating state-driven transmission needs, the REAP provides an early foundation for identifying where Illinois' priorities could align with those future processes. PJM is required to complete its intraregional compliance filing by December 2025 and implement it by June 2027, with an interregional filing (including MISO coordination) due by December 2026. MISO deadlines for the intraregional filing is in June 2026, and the interregional filing is due by December 2026. Once those filings are accepted by FERC, the ICC will have an opportunity to shape the first Order 1920 compliant planning cycles, anticipated in 2026 for PJM and 2027 for MISO, by advocating for the inclusion of REAP-identified transmission needs and priorities.

Emerging Pathways Impact on Interconnection

Emerging regulatory frameworks such as FERC Order 1920 represent an important step toward proactive, forward-looking transmission planning. These approaches aim to anticipate future system needs and develop transmission solutions that create headroom, or available capacity, for new generation and storage, rather than waiting for individual interconnection requests to drive upgrades. For Illinois, this creates an opportunity to align REAP-identified renewable energy zones and expected load growth with regional planning studies so that transmission projects are designed to enable renewable energy integration efficiently and at lower cost. Proactively creating headroom allows transmission needs to be met in a coordinated way, often at lower cost than piecemeal upgrades triggered by individual interconnection projects.

By building headroom intentionally through long-term planning, these emerging frameworks can help bridge the gap between transmission planning and interconnection reform. When implemented effectively, they can reduce the frequency and cost of network upgrades triggered by individual projects, shorten interconnection timelines, and improve predictability for developers. The REAP's IPF complements these efforts by identifying where proactive transmission investments are most likely to yield multi-value benefits.

GHG Border Pricing

The 2024 REAP highlighted the risk of increased GHG emissions from imports as Illinois pursues decarbonization. CEJA outlines a *goal* of 100% clean energy by 2050 but a *legislative requirement* of 50% RPS and zero emissions from large electricity generation in-state by 2045. As a result, this creates a potential scenario in which imported power could provide the remainder of Illinois electricity demand if economic to do so, even though GHG emissions associated with those imports may be inconsistent with the state's goals. Therefore, to measure alignment with Illinois' goal of 100% clean energy, it is important to consider how emissions associated with imported power are tracked or priced in support of Illinois goals.

With the 2024 REAP Order emphasizing GHG-leakage challenges, and recommending consideration of RTO GHG border-pricing mechanisms, this cycle further explores how such approaches could apply to Illinois. The objective of such a policy is to put in-state and out-of-state fossil fuel producers on common economic footing, meaning emissions from electricity generation would be priced the same regardless of where those emissions are produced. Elevated prices in Illinois, as a result of GHG border pricing, may spur additional investment in carbon-free resources over time. Revenues that the state collects from the GHG border price could be reinvested to deploy carbon-free resources, similar to efforts like the Regional Greenhouse Gas Initiative (RGGI). In addition to funding new carbon-free generation, RGGI states invest auction revenues in a range of consumer- and community-oriented programs, including energy efficiency upgrades for homes and businesses, direct bill rebates to offset customer costs, electrification initiatives, and workforce development programs supporting clean energy jobs. These investments helped participating states lower overall energy demand and household energy bills while advancing equitable access to the benefits of the clean energy transition.[126]

California implemented its cap-and-trade program by treating in-state and out-of-state emissions in an equivalent manner. To achieve this, California requires detailed tracking of electricity imported, including identification of source generators and their associate emissions intensity.[127] This level of attribution enables accurate accounting of imported emissions but also underscores the administrative complexity of implementing such a policy. Particularly for a state like Illinois that operates within two RTOs, it would require coordinated data collection and reporting across multiple market systems.

At the time of the 2024 REAP, PJM already published detailed emissions data, including hourly total emissions by fuel type and five-minute marginal emissions rates for individual load nodes through its Data Miner platform.[128] In response to growing stakeholder interest, MISO subsequently launched its own emissions dashboards and has expanded them to include historical, near real-time, and marginal emissions estimates, helping to narrow the gap and in some cases provide new views (such as consumed emissions at the state and county level) that are particularly relevant for states like Illinois. Starting in 2022, MISO began hosting a publicly available emissions dashboard that aggregates both historical data from the Energy Information Administration (EIA) and projected emissions from the Environmental Protection Agency (EPA), the latter of which is based on MISO's Regional Resource Assessment (RRA). After passage of CEJA, the ICC worked with MISO to obtain these emissions estimates for its analysis. In recent years, MISO has expanded its capabilities to include real-time, footprint-wide emissions at five-minute intervals as well as marginal emissions. This tool can serve as a foundation upon which a more robust emission tracking system could be built for Illinois and other member states.[129]

---

[126] Regional Greenhouse Gas Initiative, Inc. (RGGI). 2023. The Investment of RGGI Proceeds in 2023.
[127] Cleary, Kathryne, Karen Palmer, and Dallas Burtraw, "Lessons from the Literature for State Carbon Pricing Policy Design," Resources for the Future: https://media.rff.org/documents/NYSERDA_Carbon_Pricing_Report.pdf.
[128] PJM Emissions Data Viewer: https://www.pjm.com/markets-and-operations/m/emissions.
[129] "MISO Emissions Dashboard to Track Greenhouse Gas Emissions," MISO (July 2025): https://help.misoenergy.org/knowledgebase/article/KA-01501/en-us.

Findings

The findings presented in this section synthesize the analysis conducted throughout Strategic Element 5, including review of federal and regional regulatory frameworks, assessment of available planning pathways in MISO and PJM, and evaluation of how each aligns with Illinois' REAP-identified transmission needs. Together, these findings reflect the intersection of state policy objectives, regional planning processes, and emerging federal requirements under FERC Order 1920. They frame how Illinois can effectively advance its transmission priorities within existing and forthcoming regional mechanisms, while identifying where additional coordination or advocacy will be required to ensure that REAP outcomes are translated into actionable projects.

Considerations for Timeline, Cost Allocation and Relevance to REAP Needs

Table 13 illustrates the considerations among the major regulatory pathways through which transmission projects may be advanced in MISO and PJM. Each pathway varies in its frequency, the breadth of its cost allocation, and its alignment with the REAP's objectives. Frequency of process refers to how frequently the process occurs and how often it yields projects. Cost allocation refers to whether costs are allocated among local customers or regionally. Lastly, "Fit with REAP Needs" is defined as how well that regulatory pathway is aligned to identify transmission needs that serve state policy targets.

Table 13: Regulatory Pathways for Fulfilling REAP Identified Needs

Regulatory Pathway	Frequency of Process	Cost Allocation	Relevance to REAP Needs
Reliability Planning	Every 12-18 Months	Regional	Opportunity for Right-Sizing to Align with REAP Needs
Economic Planning	Every 12-24 Months	Regional	Opportunity for Right-Sizing to Align with REAP Needs
LRTP / Order 1920 Compliance Processes	Every 3-5 Years	Regional	Direct Opportunity to Address REAP Needs
State Agreement Approach	Can Propose through RTEP	Local	Direct Opportunity to Address REAP Needs
"Other" or "Supplemental" Projects	Rolling process	Local	Opportunity for Right-Sizing to Align with REAP Needs

Reliability and Economic planning processes, which are the foundation of annual RTO planning cycles, tend to move more quickly because they build on established methodologies, which is why their development timeline is relatively shorter. Their regional cost allocation structures make them attractive for Illinois from a cost burden perspective, but the fit will depend on whether reliability or economic needs also align to REAP-identified needs. These processes are designed to meet short-term needs and are not set up to study and identify long-term needs.

In contrast to the cadence and speed of reliability and economic planning processes, long-term planning processes such as **MISO's LRTP** or the forthcoming **FERC Order 1920** compliant cycles will proceed over multi-year horizons. These efforts most closely align with the REAP's long-term, policy-driven focus, as they explicitly incorporate state laws, resource mix changes, and decarbonization targets into scenario-based planning, increasing the likelihood that the planning process will identify the same needs as the REAP. However, the extended timelines and procedural complexity of these pathways mean they may take longer to yield actionable projects.

The **State Agreement Approach** (in PJM) or comparable mechanisms in MISO derived from Order 1920 compliance, can directly advance Illinois-specific transmission priorities. These processes require the state(s) advancing the project to directly bear project costs. As a result, if using this pathway, Illinois customers may shoulder all of the costs for projects that also benefit the broader region, if neighboring states decline to participate. These arrangements also rely on complex, time-consuming negotiations between state agencies and the RTO, which may introduce additional regulatory risk.

More localized project types, such as **Supplemental or "Other" projects,** offer faster implementation; these projects are funded entirely by the local TO and its ratepayers. These pathways exist to allow transmission owners to address local needs that are not captured in regional reliability or economic planning cycles, such as asset condition replacements, load-growth pockets, or equipment nearing end-of-life. Supplemental and "Other" projects also are not subject to the same level of review by regulators and stakeholders as projects that go through Reliability and Economic planning processes. These projects may still support REAP objectives if paired with a right-sizing strategy, where incremental capacity or voltage upgrades are added to projects already planned for local reliability to increase headroom for renewable deliverability.

Collectively, these considerations underscore that no one regulatory pathway is likely to be the sole vehicle to address REAP needs. Rather, pursuing multiple pathways in parallel will provide the state with optionality and flexibility to enable a regional transmission buildout that cost-effectively meets Illinois' clean energy goals.

Interregional Coordination between MISO and PJM

While MISO and PJM are required under FERC Order 1000 to coordinate interregional planning, until recently the coordination that occurred was largely procedural, and few joint projects were advanced. Their respective planning cycles, scenario frameworks and analytical frameworks were not well-aligned. As a result, even when a potential project provided mutual benefits, it often failed to satisfy one region's benefit-cost criteria or was studied under assumptions that did not align temporally or methodologically with the other region's studies.

Recent developments, however, mark a meaningful shift toward more substantive interregional coordination. In May 2024, MISO and PJM jointly announced a new Interregional Transfer Capability Study (ITCS), committing to deeper analytical collaboration and coordinated modeling. The 2024–2025 ITCS represents a step forward. The RTOs developed a blended model that integrates plausible long-term assumptions for both regions, harmonizes policy-driven retirements and new generation additions, applies consistent load forecasts, and evaluates reliability, economic, and transfer capability needs on a common basis. Preliminary results released at the March and June 2025 IPSAC meetings identified multiple shared transfer limitations along the seam and demonstrated that addressing these constraints provides mutual reliability and economic benefits.[130]

In addition to the coordinated study approach, the RTOs have begun to outline shared next steps to translate the ITCS findings into actionable pathways. MISO opened a conceptual solution window in May 2025, receiving

---

[130] *MISO/PJM Interregional Transfer Capability Study (February 27, 2025): https://www.pjm.com/-/media/DotCom/committees-groups/stakeholder-meetings/ipsac/2025/20250307/20250307-miso-pjm-ipsac-interregional-transfer-capability-study-itcs-to-pjm---working-draft.pdf. https://cdn.misoenergy.org/20250625%20MISO-PJM%20IPSAC%20Item%2002%20ITCS%20Update704126.pdf.*

34 proposed upgrades from stakeholders, which, together with MISO- and PJM-developed concepts, are being jointly reviewed for technical merit.[131] PJM has similarly begun evaluating overlaps between ITCS-identified needs and its existing RTEP reliability, Market Efficiency, and end-of-life (M3[132]) processes, including opportunities to right-size ongoing projects to better address seam constraints.[133] Both RTOs have also stated that they will continue to explore whether additional project types, such as enhanced Targeted Market Efficiency Projects, developing something like PJM-SPP's Interregional Market Efficiency Projects, or new interregional categories consistent with Order 1920 compliance, may be needed to capture the full set of reliability, economic, and transfer benefits revealed in the study.[134]

These steps do not eliminate all challenges of interregional coordination, but together they represent a material evolution since the 2024 REAP. The development of a shared long-term model, the identification of common limiting elements, and the establishment of coordinated next steps signal that both RTOs are moving toward an interregional planning framework better aligned with the needs of states. Because this new joint transfer capability study already addresses many of the issues the Commission had hoped a JTIQ-style effort would resolve, as indicated in the 2024 REAP Order, the ICC Staff has reported that an additional JTIQ-type study is not necessary at this time.[135]

Evolving Interconnection Processes to Leverage Proactive Transmission Development

Both MISO and PJM have recently taken steps to evolve their interconnection processes in ways that may enable faster use of transmission headroom created through proactive planning. These changes are particularly relevant for REAP zones where transmission upgrades identified in this cycle, or subsequent cycles, may provide meaningful transfer capability or local headroom for new renewable and storage resources.

In PJM, the 2024–2025 reforms to Surplus Interconnection Service (SIS), which ICC supported, expanded eligibility for surplus service and removed restrictions that previously prevented developers from using unused interconnection capability at planned or operating facilities. The new rules allow surplus service from both existing and planned generating units, permit surplus service even when additional physical interconnection facilities are needed, and align PJM's manuals with Open Access Transmission Tariff (OATT) changes that FERC approved in February 2025.[136] These changes create a more flexible, expedited pathway for resources to utilize unused interconnection capability and importantly allow projects to interconnect outside the full cluster study process when system impacts are minimal. As new transmission projects come online in Illinois, these reforms may make it easier for resources to connect quickly and begin delivering energy using available headroom.

MISO is also updating its Surplus Interconnection process with proposed revisions to Attachment X and BPM-015 to improve study timelines, use updated models, better manage modifications to host units, and more

---

[131] *Ibid.*
[132] *The "M3" process refers to PJM's Asset Management / End-of-Life (EOL) planning category, under which transmission owners identify facilities requiring replacement due to age, condition, or obsolescence. M3 projects are reviewed by PJM for need and potential right-sizing opportunities but are not PJM-selected RTEP solutions; cost responsibility generally follows existing local transmission owner allocation rules.*
[133] *Ibid.*
[134] *Ibid.*
[135] *ICC Staff Compliance Report, Public Utilities Bureau (June 28, 2024): https://www.icc.illinois.gov/docket/P2022-0749/documents/352340/files/616595.pdf.*
[136] *PJM Manual 14H Revisions – Surplus Interconnection Service (March 19, 2025): https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2025/20250319/20250319-item-03---1-surplus-interconnection-services-revisions---presentation.pdf.*

clearly define eligible surplus capacity.[137] While the reforms are narrower in scope than PJM's recent changes, these updates reflect MISO's broader interest in providing more flexible, lower-cost interconnection options, particularly where transmission capacity already exists due to approved LRTP or reliability upgrades.

Taken together, these actions indicate that both RTOs are moving toward interconnection frameworks that may better leverage proactive transmission investments. If REAP-identified upgrades create additional headroom in certain zones, PJM's revised Surplus Interconnection Service and MISO's evolving surplus processes could enable projects to interconnect more quickly, reduce redundant study requirements, and make earlier use of transmission upgrades. While additional reforms may still be needed, current RTO initiatives already represent a meaningful shift toward interconnection processes that can accelerate renewable and storage development in areas where proactive transmission planning has lowered system constraints.

Recommendations

Regulatory Pathways for Transmission Development

This report recommends five potential regulatory pathway strategies for facilitating REAP identified transmission needs. These pathways are not mutually exclusive. As discussed in the Findings - multiple pathways can, and should, be pursued simultaneously. The following recommendations are intended as options for the ICC to further advocacy at the RTOs. These recommendations are guided by a set of core principles. First, all strategies should align to the principle that costs customers pay for transmission is roughly commensurate with benefits. Second, long-term transmission planning and pathways are critical to meet REAP needs. And, lastly, these broad recommendations are subject to the case-by-case fact basis of any given project.

[137] *MISO Surplus Interconnection Attachment X and BPM-015 Updates (October 8, 2025): https://cdn.misoenergy.org/20251008%20PAC%20Item%2004b%20Surplus%20Interconnection%20Attachment%20X%20and%20BPM%20015%20Updates%20(PAC-2025-3)721323.pdf.*

Figure 43: Summary of Regulatory Pathway Recommendations

Prioritize Regional Allocation Pathways	Expand Regional Allocation Pathways	Coordinate with Emerging Planning Processes	Leverage Right-Sizing for REAP Needs	Support Coordination of Regional Processes	Leverage Transmission Upgrades for Faster Interconnection
Prioritize regulatory pathways that **emphasize regional cost allocation**	Explore expanding regional cost allocation pathways to **enable state-driven projects** with cost allocation **reflecting shared regional benefits**	**Coordinate REAP planning efforts with emerging Order 1920 processes,** which offer a strong fit for REAP-identified needs	REAP analysis can help **ICC identify opportunities where right-sizing can reduce costs for Illinois customers while supporting policy goals**	**Support continued coordination** of processes between MISO and PJM to further **develop interregional needs**	Examine if surplus interconnection reforms **can be extended to proactive transmission upgrades** that create headroom for renewables

Prioritize Regional Allocation Pathways

The first recommendation is to prioritize regulatory pathways that support (where applicable) regional cost allocation when appropriate and competitively bid transmission, while also pursuing right-sizing opportunities under other pathways, as discussed further below. These pathways include the PJM Baseline, MISO Baseline, MVPs and emerging Order 1920 options. Working within these established and evolving regional mechanisms allows Illinois to pursue transmission investments that reflect the full range of reliability, economic, and policy benefits shared across states. As regional markets continue to evolve under new federal planning requirements, focusing on these pathways ensures that Illinois remains aligned with regional cost-allocation frameworks and can leverage opportunities for broader benefit sharing as well as potential customer cost savings enabled through competition. These pathways also align with the broader principle that customers pay for costs roughly commensurate with the benefits they receive. Because Illinois is integrated into both the MISO and PJM grids, many upgrades located in the state may produce cascading benefits for neighboring regions, noting that no state should pay for lines it does not benefit from. Maintaining emphasis on processes that support regional cost allocation for projects that provide regional benefits helps ensure that these shared benefits are recognized and that associated costs are equitably distributed before considering approaches where Illinois ratepayers would bear those costs alone.

Expand Regional Allocation Pathways

The next recommended strategy is to expand regional allocation pathways such that a state can advance a project while costs are allocated roughly commensurate with benefits between state specific and region wide benefits. For example, states could retain the ability to prioritize transmission projects that advance their goals, while cost allocation would take into account the regional distribution of benefits that those same projects provide. This approach should also be explored as a way of supporting and promoting opportunities to right-size projects to meet state objectives.

To advance this concept, within MISO and PJM stakeholder forums ICC could explore modifications to existing cost allocation frameworks, such as those applied to Baseline Reliability or Economic Projects, to formally accommodate state-prioritized projects. This may include supporting tariff revisions or pilot mechanisms that enable a state to nominate a project addressing a shared regional need but agree to fund the incremental component relevant to their state. The objective is to build on established processes, rather than create wholly new pathways, by clarifying how states can use existing planning frameworks to advance projects with wider benefits without shouldering their entire cost.

Coordinate with Emerging Planning Processes

Looking ahead, the ICC could also support the incorporation of this incremental-cost model into emerging "state-initiated" planning pathways being developed under FERC Order No. 1920. These forthcoming processes are intended to provide states with a more formal role in identifying and selecting transmission projects that meet state policy needs. By advocating for a structure that recognizes and separates regional and state benefits, Illinois can help ensure that new policy-driven projects under Order 1920 reflect both regional fairness and state autonomy. Together, these efforts would position Illinois to pursue REAP transmission priorities in a manner that shares costs fairly while maintaining alignment with regional planning principles.

Coordinating REAP planning efforts with emerging Order No. 1920 processes will be critical to ensure that future regional planning frameworks reflect Illinois' policy goals and protect ratepayer interests. As MISO and PJM develop tariff revisions to comply with FERC's new long-term planning requirements, the ICC should remain actively engaged to ensure that these tariffs explicitly account for state laws and policies when developing planning scenarios. Continued advocacy in these proceedings will help ensure that scenario planning under Order 1920 captures Illinois' statutory renewable energy and decarbonization requirements. Once compliant tariffs are established, future REAP analyses can serve as a key input to those planning cycles, offering data and scenarios that reflect Illinois' unique system conditions and policy drivers. Maintaining alignment between REAP scenarios and those used in the long-term regional planning processes will increase the likelihood that regional studies identify the same transmission needs and policy-driven investments prioritized through the REAP.

Leverage Right-Sizing for REAP Needs

Right-sizing transmission projects represents a practical strategy that can be applied across multiple regulatory pathways. Right-sizing involves upgrading or replacing existing transmission assets at higher capacity or voltage to accommodate future renewable energy growth and improve system reliability. Because it builds on projects already planned for replacement or reinforcement, right-sizing can deliver multiple benefits by meeting asset condition or reliability needs while also supporting policy goals such as renewable energy deliverability and system resilience.

For example, given the large share of investment that flows through "Other" or "Supplemental" transmission projects developed by incumbent transmission owners, there is significant opportunity to align these projects with broader REAP objectives. By identifying where such projects can be expanded or optimized to address future system needs, the ICC can help ensure that Illinois ratepayer-funded investments deliver the greatest overall value. This could similarly be applied to Baseline Reliability Projects, where right-sizing a project could deliver incremental benefit to renewable energy deliverability. Order 1920 also calls for RTOs to assess right-sizing opportunities to meet needs, providing another avenue for this strategy. Integrating right-sizing considerations into both regional and local planning processes can create pathways for near-term progress toward Illinois' renewable energy integration and reliability goals.

Support Coordination of Regional Processes

Improved coordination between regional planning processes remains essential for long-term progress and recent steps by MISO and PJM represent a meaningful shift towards productive collaboration. Through their ongoing Interregional Transfer Capability Study (ITCS), the RTOs have begun using a shared long-term model, harmonized assumptions, and coordinated reliability, economic, and transfer analyses.

Given this progress, the ICC should focus on supporting, strengthening, and institutionalizing the steps MISO and PJM have already undertaken. First, Illinois should encourage the RTOs to continue refining the blended modeling framework used in the ITCS, including maintaining consistent scenario assumptions and applying harmonized methods for evaluating policy-driven resource additions and retirements.

Second, the ICC should support MISO and PJM's efforts to translate ITCS findings into actionable solution pathways. This includes advancing the evaluation of stakeholder-proposed upgrades submitted through MISO's 2025 conceptual solution window. The ICC can continue to work with the RTOs on identifying regulatory pathways for projects identified in the ITCS. The RTOs have already identified a number of potential pathways including PJM's RTEP reliability and Market Efficiency processes, expanding TMEPs, investigating M3 processes to right-size ongoing projects, or new Order 1920 processes. These steps would ensure that promising seam solutions identified in the ITCS do not stall simply because no existing project category fully captures their multi-benefit value. This same issue parallels Illinois' broader need for expanded regulatory pathways for REAP-identified transmission needs. Drawing this link highlights the value of pursuing more flexible, benefits-aligned pathways that can accommodate both Illinois-driven and regionally driven transmission solutions.

Third, Illinois should continue to use and strengthen existing coordination forums, particularly the Interregional Planning Stakeholder Advisory Committee (IPSAC), OMS–OPSI joint task forces, and other state-RTO engagement channels, to provide consistent feedback on assumptions, study timelines, and proposed solutions. These forums are now central to the ITCS workflow and provide venues for Illinois to advocate for the inclusion of REAP-identified constraints, clean energy delivery needs, and long-term policy objectives in subsequent rounds of interregional analysis.

By building on the momentum established through the ITCS process and reinforcing the steps that MISO and PJM have already taken, Illinois can help ensure that interregional planning evolves into a more coordinated, transparent, and policy-aligned process, one capable of delivering the shared reliability, economic, and clean energy benefits that a well-planned MISO–PJM seam can provide.

Explore Leveraging Transmission Upgrades for Streamlined Interconnection

ICC should examine whether the principles underlying the RTOs' surplus interconnection reforms can be extended to transmission projects identified through the REAP that proactively create headroom for renewables interconnection. In PJM, for example, these reforms focus on using available headroom, applying streamlined studies, reducing unnecessary restudies, and allowing generators to utilize surplus interconnection service even when limited additional interconnection facilities are needed at the point of interconnection. These principles could apply to transmission upgrades in REAP zones. This could offer one practical avenue for ensuring that headroom created by proactive transmission investments is fully accessible to new renewable and storage resources.

Appendix A. Summary of 2024 REAP and 2025 Draft REAP Recommendations

The following table summarizes the 2024 REAP Recommendations and the 2025 Draft REAP Recommendations for each Strategic Element.

There are a few key shifts in the framing of Strategic Elements this REAP that are worth noting. For example, in Strategic Element 4: Effective Transmission Planning and Utilization, the 2024 REAP focused on the immediate need for interconnection reform. As noted earlier in this introduction, interconnection reform has evolved significantly since the last report. In this cycle, Strategic Element 4 focuses on transmission planning to create headroom in particular focused on ATTs and NWAs, while Strategic Element 5 examines the regulatory and market mechanisms necessary to translate that physical headroom into actual interconnection opportunities and deliverability. This reframing ensures that planning and policy discussions are connected from concept to implementation.

Another important evolution is the repositioning of transmission regulatory pathways. In the 2024 REAP, those pathways were discussed within Strategic Element 4, alongside technical transmission planning topics. In this cycle, that discussion moves to Strategic Element 5, where it is framed in the broader context of how Illinois engages with regional and interregional processes. This shift highlights the REAP's growing focus on the state's role in shaping and leveraging regional planning and market structures. As a result, Strategic Element 5 now extends beyond market design and trade to include policy alignment, regulatory advocacy, and engagement in Order 1920 processes that determine how Illinois' policy priorities are represented at the RTO level.

Strategic Element	Summary of 2024 REAP Recommendations	Summary of 2025 Draft REAP Recommendations
1. Tracking Progress Toward Illinois' Policy Goals	+ Illinois must dramatically accelerate renewable deployment to meet CEJA + ICC Staff will issue annual reports tracking progress on CEJA goals to inform future REAP cycles. + Establish a REAP Working Group and hold public workshops.	+ Tracking Illinois' progress towards state policy targets amid an evolving landscape enables early identification of risks, such as data-center driven demand growth, that could challenge CEJA compliance. + Next REAP should continue building stakeholder engagement through stakeholder workshops and the technical working group. + Next REAP cycle should further build out a community engagement strategy, building on this REAP cycle. This includes hosting additional webinars that are focused on engaging communities most impacted by REAP zone development and building strategic partnerships with organizations and entities that can help expand that reach.
2. Transitioning to a Decarbonized Electricity Mix	+ ICC Staff will study economy-wide decarbonization strategies to refine resource needs, mix, and enforcement mechanisms. + Prioritize near-term fixes (demand response, grid-enhancing tech) while pushing for proactive transmission planning (esp. in PJM) and leveraging retiring plant sites for new clean resources.	+ Additional scenario analysis to evaluate impacts of electrification for economywide decarbonization, inter-regional transmission expansion, etc. + Continue to update assumptions to maintain alignment with latest planning efforts at the utility and RTO level + Additional exploration of ATTs and NWAs using the Integrated Planning Framework + Demonstrating the remaining steps in the Framework with identification of near-term actions and mapping long term resource additions to substations to refine subsequent transmission analysis

3. Managing Land Use in Renewable Deployment	+ Adopt REAP zones: Level 1 and Level 2 + Conduct a Comprehensive Transmission Headroom Analysis with PJM/MISO to identify available interconnection capacity and low-cost upgrade options (including GETs). + Consider a model county ordinance for responsible siting in counties lacking up-to-date rules.	+ Continued analysis to estimate suitability of land for infrastructure development is key to refine REAP zones and informing siting of resources + Continued refinement of assumptions and scenario exploration with the IPF is key to refining potential infrastructure needs across different zones, and understanding the associated land use impacts + Continued outreach to communities that may host energy infrastructure as results from the REAP become increasingly actionable
4. Effective Transmission Planning & Utilization	+ ICC to advocate for interconnection queue reform at FERC and with the RTOs. + ICC will host quarterly meetings with RTOs; utilities must report annually on PJM/MISO transmission solutions. + ICC Staff to advocate for: (1) PJM/MISO reforms (scenario-based planning, policy drivers in RTEP), (2) joint PJM–MISO interconnection study, (3) greater use of GETs, and (4) prioritization of NWAs.	+ Future REAP cycles should investigate ways to evaluate ATTs as part of the Integrated Planning Framework + Future REAP cycles should explore where DERs, flexible load and other NWAs may provide locational value + ICC could direct Ameren and ComEd to identify ATT opportunities on their systems that could aid in meeting REAP zone needs.

5. Leveraging Regional Processes and Markets	+ MISO Zone 4 resource adequacy gap is urgent; Illinois may need new capacity procurement mechanisms + Expand GHG emissions data to track leakage and support Scope 2 accounting + Pursue clean attribute markets for RECs/ZECs/CMCs and potential "clean capacity" products. + Support RTO reforms to align markets with state policies and plan for fossil retirements under CEJA emissions limits. Legislative authorization may be needed for Illinois to participate in regional attribute/GHG markets.	+ Prioritize regulatory pathways for transmission development that enable regional allocation of costs. + Advocate for expansion of annual planning pathways where states only cover the incremental costs of advancing state goals + Coordinate REAP planning efforts with emerging Order 1920 processes for effective long-term transmission planning + ICC to examine opportunities to where right-sizing or incremental upgrades can help reduce costs for Illinois customers while supporting REAP policy goals + Support and strengthen MISO–PJM Interregional Transfer Capability Study efforts to align assumptions, advance identified solutions, and improve interregional coordination + Explore enabling accelerated interconnection of resources in areas where proactive transmission upgrades create headroom

Appendix B. Strategic Element 2

Peak Load Forecasts

In line with annual load, the peak load is also forecasted to grow significantly as shown in Figure 43, Figure 44, Figure 45, and Figure 46. Data center loads are assumed to be fairly steady with slightly higher cooling loads in the summer. Given this dynamic, each region stays summer peaking through the end of the study period. With higher levels of electrification, especially of space heating, the winter peak may become more dominant. Scenarios with higher levels of electrification will be considered in the future.

Figure 43: PJM Peak Load Forecast (GW)

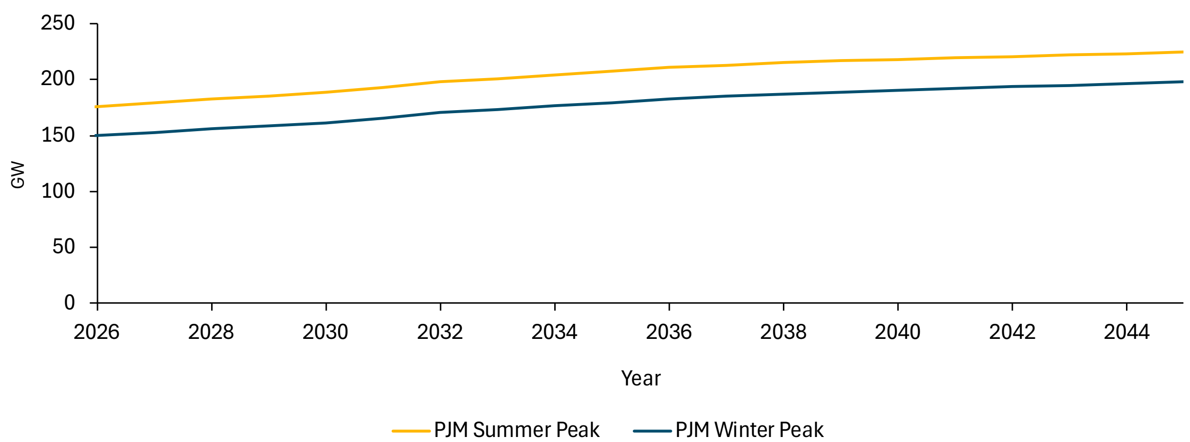


Figure 44: ComEd Zone Peak Load Forecast (GW)

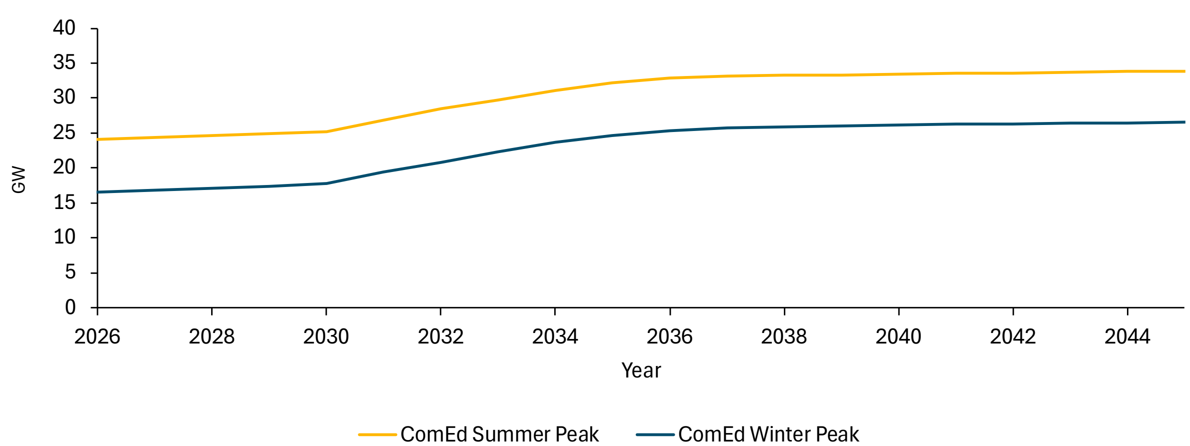


Figure 45: Peak Load Forecasts in MISO and MISO North

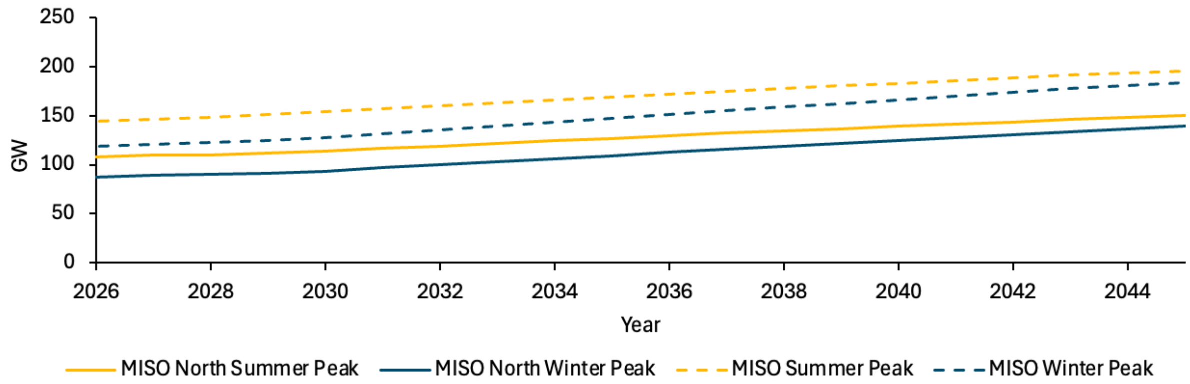
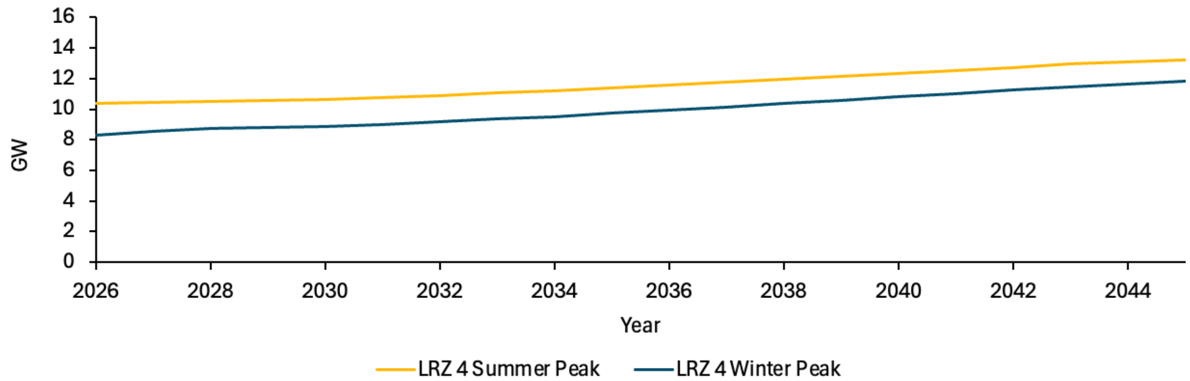


Figure 46: LRZ 4 Peak Load Forecast (GW)



Effective Load Carrying Capabilities

ELCC is defined as the perfect capacity equivalent to a resource. E.g. if the ELCC of a 100 MW solar resource is 50%, it implies that the resource provides the same effective capacity contribution in critical hours as a 50 MW perfect resource available 24/7 without outages. Measuring the capacity value of each resource using ELCCs allows the model to compare different resource types on a level playing field and build a cost optimal portfolio of resources such that the portfolio ELCC is at least equal to the reliability requirement.

Calculating the ELCC for a resource is a three-step process. First, a representation of a "base" portfolio of resources and loads is developed and "tuned" via the addition of perfect capacity to meet a desired reliability target (e.g., LOLE of 0.1 days per year). Next, the resource of interest is added to the portfolio, resulting in an improvement in reliability. Finally, through an iterative process, perfect capacity is removed until the original level of reliability is restored. In this process, the amount of perfect capacity removed is equal to the resource's ELCC.

Figure 47: ELCC Calculation Methodology

Load and resource portfolios evolve over time. As a result, the system needs and the ELCC that the next tranche of a given resource type can provide also changes with the resource penetration. To capture these dynamics, ELCC "curves" were developed. A curve shows the ELCC of a given resource type at different levels of nameplate penetration.

ELCC curves were produced for 3 resource classes: wind, solar, and 4-hour storage. ELCC curves were built sequentially to ensure that interactions between different resource types are also captured. These curves were developed for each of the 4 regions studied: MISO North, PJM, LRZ 4, and ComEd to capture the load-resource interactions unique to each region.

ELCC curves produced for the four regions are shown in Figure 47 to Figure 51. A four-hour battery, solar, and wind all provide diminishing returns as penetration increases. Gross load generally peaks in the middle of a summer day driven by cooling loads. The first tranche of solar gets a high ELCC, because solar production in these hours is relatively high. However, as more solar is added to the system, the net peak load gradually shifts outside the hours solar contributes the most to leading to diminishing ELCCs with increasing penetration. Wind ELCCs start lower than solar ELCCs because wind production is relatively anti correlated with load under current assumptions.[138] Wind production is typically stronger overnight and stronger in the winter than in the summer. Wind ELCCs also degrade with increasing penetration of wind, because like solar as more wind is added, the net peak gradually shifts to hours where wind production is not strong.

Four-hour battery storage is subject to similar dynamics. ELCCs start high since high load/ high risk events are relatively shorter in duration at first. But once these shorter duration events are resolved, the remaining net peak is now longer in duration leading to diminishing returns with the next tranche of 4-hour battery storage.

The trend is consistent across all four regions. The exact values vary based on the load-resource interactions within each region. Since MISO and PJM are significantly larger systems than ComEd and LRZ 4 respectively, the ELCC degradation is slower (e.g., 20th GW of four-hour battery storage gets 60% ELCC in PJM but 21% ELCC in ComEd). Using ELCC curves specific to each of the four regions in PLEXOS ensures that the resource portfolios selected maintain both "local" reliability within Illinois zones and RTO-wide reliability.

---

[138] With high electrification, this may change. For example, space heating loads are highest in the winter outside daylight hours when wind is stronger.

Figure 48: PJM ELCC Curves

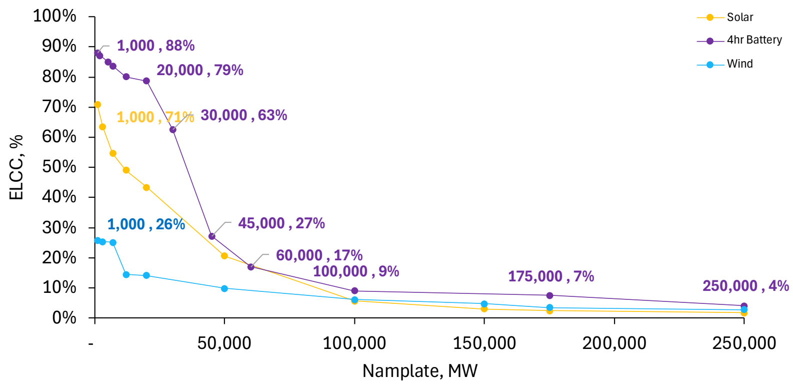


Figure 49: MISO North ELCC curves

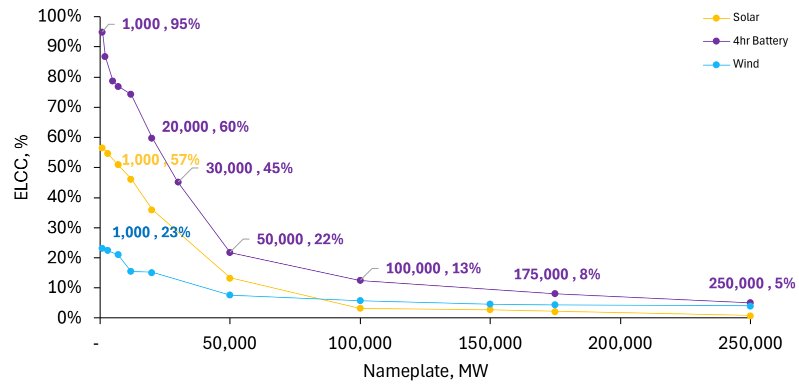


Figure 50: ComEd ELCC Curves

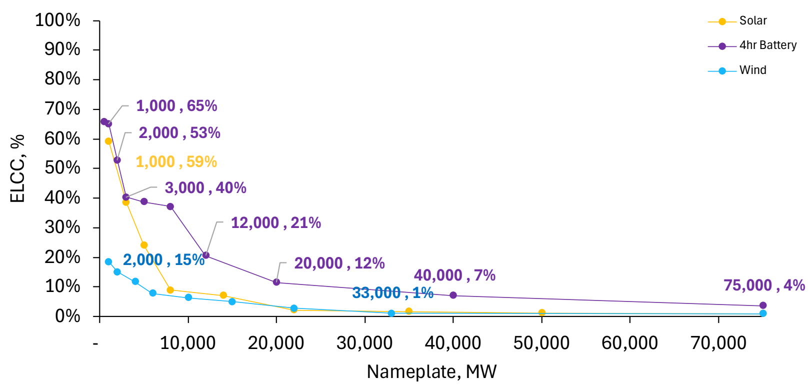
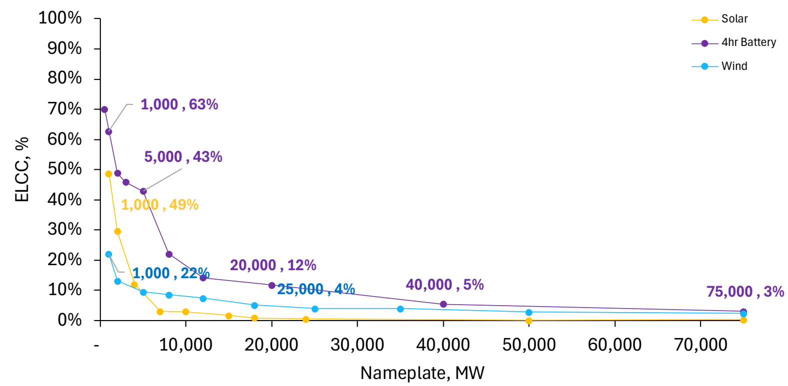


Figure 51: LRZ 4 ELCC Curves



Planning Reserve Margin

The Planning Reserve Margin (PRM) is measured as the quantity of effective capacity needed above the median peak load expectation. This accounts for the possibility of load exceeding the median peak expectation and ensures that a 1-day-in-10-years reliability target can be achieved. The PRM requirement in each of the four regions were calculated, informed by their respective load shapes. Because all resources were accredited using a perfect capacity framework (i.e ELCCs), only load variability is accounted for in the PRM. Resource outages and performance limitations are reflected in the ELCCs estimated for each resource type. Ultimately, PLEXOS builds sufficient resources to ensure that the total sum of ELCCs from all resources is greater than or equal to the median peak load grossed up for the PRM.

Table 14: Planning Reserve Margin by Region (% of Median Peak Load)

Region	PRM
PJM	7.5%
MISO	5.5%
ComEd	8.3%
LRZ 4	5.8%

Resource Costs

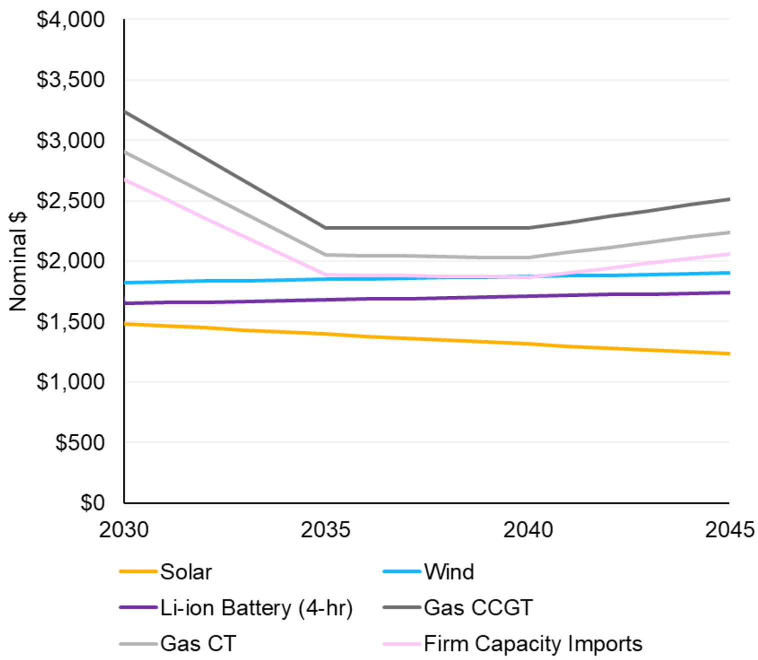
Figure 52 presents Illinois-specific upfront capital expenditure (CapEx) forecasts for key generation and storage resources modeled. These projections are primarily based on the National Renewable Energy Laboratory's Annual Technology Baseline[139], adjusted to reflect current market conditions. The trends illustrate both technological progress and inflationary effects over time. Declining nominal costs (e.g., for solar) indicate that real cost reductions are expected to outpace inflation, while rising or flat trajectories (e.g., for gas technologies) suggest that inflation will dominate any efficiency gains. Key modeling assumptions include the sunset of tariff impacts by 2030, expiration of solar and wind tax credits before 2030 (in line with the OBBBA), ineligibility of storage for investment tax credits under current FEOC restrictions, and short-term gas turbine scarcity premiums that normalize by 2035.

PLEXOS is also allowed to select firm imports if economic, which are modeled at the cost of constructing new gas combustion turbines (CT) in neighboring states. This approach reflects Illinois' strong transmission connections to the rest of the RTOs and the possibility of partially relying on imports. It is priced at the cost of building new gas to reflect the RTO-wide capacity tightness expected and the potential need for new generation in the rest of the RTO for IL to confidently rely on imports and maintain reliability. In-state gas CTs are slightly more expensive than firm imports given higher labor costs and taxes relative to neighboring states and a hydrogen readiness cost imposed on them so they can comply with CEJA by 2045.

New nuclear is also a candidate resource, with estimated CapEx ranging between $10,000 and $13,000 per kW over the modeling horizon, consistent with NREL Annual Technology Baseline benchmarks.

[139] *NREL 2024 Electricity Annual Technology Baseline (ATB) Data: https://atb.nrel.gov/electricity/2024/data.*

Figure 52: Resource CapEx, Nominal $/kWac



Firm Imports Limits

Table 15 represents the total transmission line capacity linking Illinois zones to the rest of the respective RTOs in 2030. In any given hour on a representative day in PLEXOS, imports are constrained by this amount. Projects recently approved by MISO via the LRTP and MTEP processes and PJM through the RTEP process are reflected in the model. The resulting line capacity in 2045 is shown in Figure 53.

While these figures represent the import capability on a representative day, the import capability during the most challenging hours is generally lower. The Capacity Emergency Transfer Limit (CETL) and Zonal Import Ability (ZIA) constraints from MISO and PJM respectively inform the firm import capability towards meeting the PRM requirement (Table 15). CETL for ComEd is assumed to be 5.7 GWs in the first model year based on PJM's 2026/27 Base Residual Auction Planning Period Parameters report published May 9, 2025[140]. ZIA for LRZ 4 is assumed to be 7.7 GW in the first model year. MISO ZIAs are based on MISO's 2025-26 PY Seasonal CIL/CEL Final Results report published Oct 24, 2024[141]. CETL and ZIA values increase over time in proportion to the transmission line expansion over time.

Table 15: ZIA and CETL Assumed for LRZ 4 and ComEd Zone Respectively (MW)

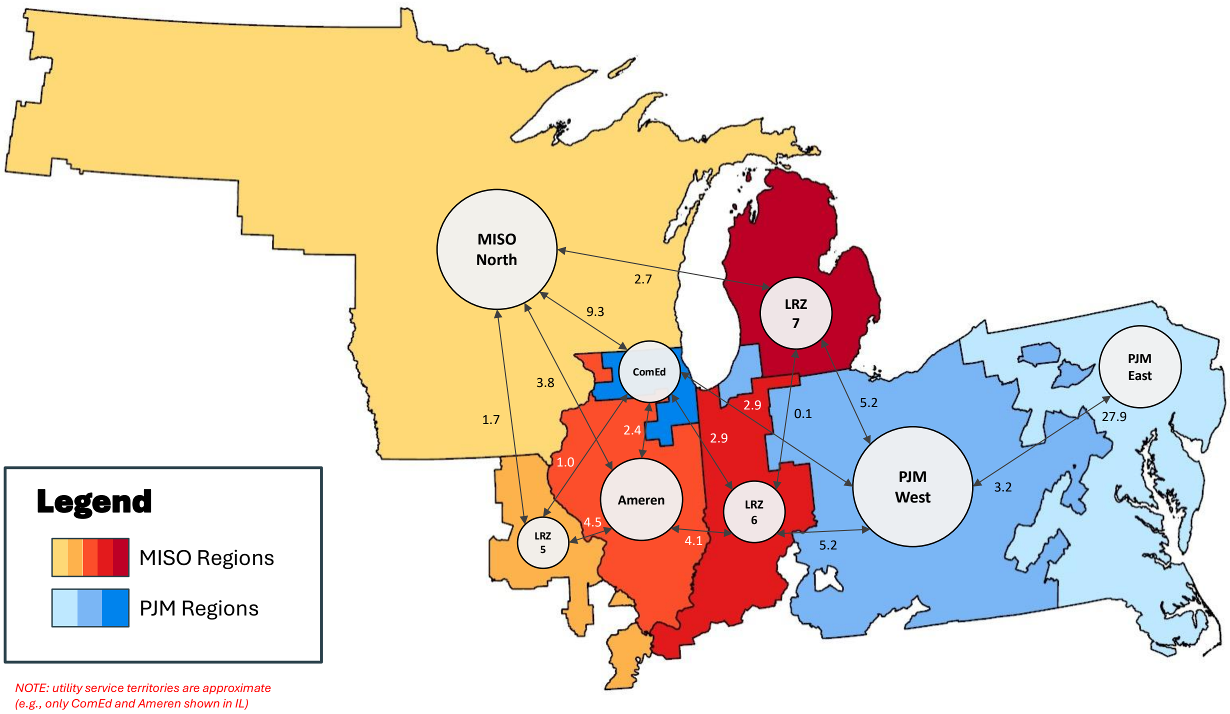
	2030	2035	2040+
LRZ4 ZIA	7,757	11,505	11,723
ComEd CETL	5,700	7,283	7,283

[140] PJM 2026/2027 RPM Base Residual Auction Planning Parameters (May 9, 2025): https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2026-2027/2026-2027-planning-period-parameters-for-base-residual-auction-pdf.pdf.

[141] MISO 2025-2026 PY Seasonal CIL/CEL Final Results, LOLE Working Group (October 24, 2024): https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2004%20PY%202025-2026%20Final%20CIL_CEL%20Results654989.pdf.

Transmission Upgrades

Figure 53: PJM & MISO Transmission Topology in 2045



Appendix C. Strategic Element 3

Transmission Headroom Utilization Coefficients

Chapter 3 describes how local transmission network headroom utilization and upgrades are tracked. Table 16 shows transmission headroom utilization coefficients ("coefficient") assumed for solar and wind. These are calculated based on average generation between the hours of 4-8 pm June-September. Firm resources like nuclear and gas are assumed to have a coefficient of one. At this stage, only one deliverability period has been modeled which assumes "on-peak" storage discharge, meaning dispatch coincides with peak demand. Accordingly, battery storage is also assumed to have a coefficient of one. In the future, additional deliverability windows can be modeled. E.g. storage could receive a negative coefficient to reflect charging in hours where renewable generation peaks and can be stored for later.

Table 16: Transmission Headroom Utilization Coefficients for Solar and Wind by REAP Zone

Region			Solar	Wind
REAP Zone	**Utility**	**RTO**	**Tx Headroom Utilization Coefficient**	**Tx Headroom Utilization Coefficient**
Greater Chicago	ComEd	PJM	0.37	0.24
ComEd South	ComEd	PJM	0.37	0.23
1	ComEd	PJM	0.37	0.24
2	Ameren	MISO	0.37	0.26
3	Ameren	MISO	0.37	0.24
4	Ameren	MISO	0.37	0.23
5	Ameren	MISO	0.38	0.18
6	Ameren	MISO	0.37	0.24
7	Ameren	MISO	0.37	0.22
Greater Peoria	Ameren	MISO	0.37	0.24
Southern IL	Ameren	MISO	0.38	0.21

**0.37 implies 37 MW of transmission headroom is assumed to be utilized for every 100 MW of a resource added*

Interconnection Costs

The interconnection costs assumed for renewable resources in this study represent a capacity-weighted average of all candidate project areas in a given REAP zone from NREL's supply curve data[142] and are presented

[142] *Anthony Lopez et al., "Solar Photovoltaics and Land-Based Wind Technical Potential and Supply Curves for the Contiguous United States: 2023 Edition," National Renewable Energy Laboratory (January 2024): https://docs.nrel.gov/docs/fy24osti/87843.pdf.*

in Table 17. Further refinement of interconnection costs is expected in future cycles based on more granular geospatial analysis.

Table 17: Renewable Interconnection Cost by REAP Zone

Region			Solar	Wind
REAP Zone	**Utility**	**RTO**	**IX Cost 2024 $/kW**	**IX Cost 2024 $/kW**
Greater Chicago	ComEd	PJM	$76	N/A
ComEd South	ComEd	PJM	$99	$137
1	ComEd	PJM	$103	$149
2	Ameren	MISO	$66	$88
3	Ameren	MISO	$75	$99
4	Ameren	MISO	$75	$89
5	Ameren	MISO	$60	$96
6	Ameren	MISO	$89	$116
7	Ameren	MISO	$80	$101
Greater Peoria	Ameren	MISO	$60	$92
Southern IL	Ameren	MISO	$76	$101

Baseline interconnection costs for non-renewable resources were drawn from the 2024 NREL Annual Technology Baseline. State-level adjustment factors were then applied informed by data from LBNL's *"Queued Up"* report[143]. The interconnection costs assumed for non-renewable resources in Illinois follow -

- 4-hr lithium-ion battery storage: $94/kW
- H_2-ready gas CT & CCGT: $101/kW
- Nuclear: $108/kW

[143] *Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection," Lawrence Berkeley National Laboratory (April 2024): https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.*