IPA
ILLINOIS POWER AGENCY

Illinois Power Agency 2024 Policy Study

Prepared pursuant to P.A. 103-0580

March 1, 2024

Illinois Power Agency
105 W Madison Street, Suite 1401
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Governor Pritzker
Senate President Harmon
House Speaker Welch

As required by Section 1-129 of the Illinois Power Agency Act (enacted through Public Act 103-0580), the IPA is pleased to release its Policy Study analyzing the potential impacts of three policy proposals from the Illinois General Assembly's Spring 2023 legislative session:

- A proposal to deploy **energy storage systems** through the development of energy storage credit targets for the Agency to procure on behalf of Illinois electric utilities, including distributed energy storage programs. (SB 1587)
- A pilot program to establish one new utility-scale **offshore wind project** in Lake Michigan that can produce at least 700,000 megawatt hours annually for at least 20 years. (HB 2132)
- A policy requiring the procurement of renewable energy credits to support a new **high voltage direct current (HVDC) transmission line** capable of transmitting electricity at or above 525 kilovolts and delivering power in the PJM market. (no bill formally introduced)

This letter has been included with the Policy Study to 1) describe the process for the Policy Study's development, 2) outline key modeling choices made in determining the impacts of these policies, and 3) walk through what this study attempts to accomplish and how its findings may be understood and used to guide public policy discussions—including what this Policy Study does not attempt to cover.

Process for Development

While the statutory obligation to conduct this Policy Study took effect on December 8, 2023 when Governor Pritzker signed Public Act 103-0580 into law, the IPA began working on the Policy Study during the summer of 2023, as we recognized that legislators and stakeholders would benefit from the Study's analyses even if the Study was not required by Illinois law.

Consequently, in August 2023, the IPA requested data specific from the proponents of the projects that would be supported by these three policy proposals. In September 2023, the IPA issued a broad stakeholder feedback request, and interested stakeholders provided responses in October 2023. In the months that followed, the Agency developed the bulk of the content for this Study and published a draft Policy Study for public comment on January 22, 2024.

Comments on the draft Policy Study were received in February 2024. While not all commenters' suggestions were adopted, the Agency reviewed all comments multiple times, and made informed decisions on what is included in the Policy Study. We have endeavored to address even the comments that were not adopted by discussing the comments and providing explanations and workpapers with the final Policy Study that was delivered to the Illinois General Assembly on March 1, 2024.

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The team that worked on the Policy Study consisted of 1) Illinois Power Agency staff; 2) the IPA's Procurement Planning Consultant, Levitan & Associates ("Levitan"); and 3) Levitan's subcontractors GE Energy Consulting and ENTRUST Solutions Group. More information on these firms and their roles can be found in Chapter 4 of the Policy Study.

Much of the Study is background and narrative intended to provide context for policymakers tasked with making difficult decisions regarding resource allocation. Substantive chapters on each of the three policy proposals from the Spring 2023 legislative session are included, with each topic addressed through analyses of approaches to similar policies taken in other jurisdictions juxtaposed against the approach proposed for Illinois. While quantitative modeling outcomes received far more attention in stakeholder comments, we genuinely hope that all who have interest in these issues diligently read these chapters and review the background provided, which provides discussion that is just as necessary for and pertinent to debate over a bill as the modeling results themselves. Accordingly, these substantive chapters were written largely for an audience composed of legislators, legislative staff, the Governor's Office, and other policymakers, and we hope that this content provides a useful foundation for engaging in informed debate around these proposals.

As mentioned above, several modeling tools were used to transform qualitative attributes—such as environmental impacts, economic impacts, grid reliability, and electric rate impacts—into measurable quantitative outputs. To study power flow and reliability, ENTRUST utilized the Siemens PTI PSS®E and PowerGEM TARA software tools, which are widely licensed and used by transmission organizations. For energy prices, capacity prices, and emissions impacts, Levitan relied on the Aurora production simulation model. To model economic impacts, Levitan utilized IMPLAN, a leading provider of economic impact data and analytical applications. For grid reliability and resource adequacy, GE Energy Consulting utilized the GE MARS model, a sequential Monte Carlo simulation providing a detailed representation of the hourly loads, generating units, and interfaces between the interconnected areas of Illinois.

These processes are described further in Chapters 4 and 8 of the Policy Study, and standalone documents of the modeling results are included as appendices to the Policy Study.

Key Modeling Choices

Using modeling tools to determine the likely impacts from policy proposals *on* a future world requires making assumptions *about* that future world. No predictions are failsafe, and a fair critique of this Policy Study – and of any other analysis attempting to model the same – is that the future may look very different that the scenario assumed in the modeling. Consequently, the projected costs and benefits of the policies operating against that backdrop may be different as well.

Nevertheless, hard choices must be made. The IPA, Levitan, and our team of subcontractors did our best to outline a scenario which best served the goal of the Study: to "evaluate the potential impacts of the proposals" across qualitative criteria reduced, where possible, to discrete quantifiable impacts. A sampling of key modeling choices made in this effort is outlined below.

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Additive Storage from Projects Paired with Distributed Generation and Community Solar Projects

Senate Amendment 1 to Senate Bill 1587 includes three policy proposals intended to incent the development of new behind-the-meter energy storage systems paired with rooftop solar, and to incent the development of energy storage systems paired with community solar projects. However, these proposals contain no procurement targets, enrollment estimates, or estimates of the incentive values. Where applicable to modeling, the IPA assumed an additional 1,000 MW of storage projects resultant from these policy proposals (additive to the 7,500 MW of utility-scale storage included in SB 1587).

Reliance on Publicly Available Data Where Possible

The IPA used publicly available information and data sources for the development of modeling inputs to maximize modeling transparency to the greatest extent possible. For example, the key assumptions used in the GE MARS modeling were based on information in GE's internal non-proprietary database, supplemented by publicly available information. However, in limited cases, the team needed to rely on data and information available only under a license. For example, due to the proprietary nature of information maintained by Energy Exemplar in the Aurora database, the limits of specific zonal links for inter-zonal transfer limitations in the model cannot be disclosed.

Choice of MISO Futures Study 1

The IPA elected to utilize the MISO Futures Study as the starting point for generation expansion, retirement, and demand. The Futures Study has been extensively documented in the MISO stakeholder process, so that many interested parties were likely familiar with the study. In the Policy Study team's view, the selection of MISO Future 1A scenario represented the use of the most "known and knowable" assumptions. Relative to Futures 2A and 3A scenarios, more of the resources included in the model are real projects under development or are identified as the result of accepted utility Integrated Resource Plans. Notably, the Futures 1A study period ends in 2042, so Levitan had to develop resource expansion for 2043 on, including positing resource retirements mandated under CEJA.

Zero Emissions Fuel Resources

After Levitan conducted capacity expansion modeling, we found that Illinois required dispatchable generation resources in the Base Case following CEJA-mandated retirements in 2040 and 2045. Storage resources were not included in the capacity expansion options to ensure the Base Case storage buildout allowed for a useful evaluation of the marginal impacts of policies supporting new energy storage projects. While many other technologies, such as flexible demand, might help mitigate the need for a zero emissions fuel ("ZEF") resource, coming up with the optimal portfolio to minimize the long-term cost impacts of CEJA was not the goal of this study. ZEFs are modeled at a high variable cost and represent a limited impact to the commitment and dispatch of proven technologies in the Aurora production cost model, and were thus included in modeling. Furthermore, the energy storage and high voltage transmission line polices studied also demonstrated reductions in the need for ZEFs.

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As outlined in Appendix E, this approach mirrors the approach taken in similar forecasting exercises by MISO, NYISO, and other planning bodies.

Reliance on Available RTO Base Case Modeling Data

As is standard in interconnection studies, ENTRUST relied on the models that have been developed by the RTOs, PJM, and MISO. These are the latest models provided by the RTOs for generation interconnection. The rationale behind using these models for the Policy Study is that these are the same models that each RTO would use in conducting interconnection studies for interconnecting customers. The data in the models is vetted by the respective stakeholders in each RTO. Additionally, the RTO models are considered Critical Energy/Electric Infrastructure Information ("CEII") and release of the data required the execution of non-disclosure agreements by ENTRUST.

Load, Capacity, and Transfer Limit Assumptions

With respect to GE MARS, for MISO's load inputs, a forecast from Purdue University was used; and for PJM's load inputs, a forecast from PJM was used. Load forecast uncertainty multipliers from the NPCC Long Range Adequacy Overview ("LRAO") was also used for both forecasts.

Capacity data was based on GE's internal non-proprietary database, supplemented by publicly available information. Renewable capacity was added to meet announced policy mandates.

- For energy storage systems, the modeling included 7,460 MW of energy storage with 4-hour storage duration and 85% round trip efficiency, and 40 MW of energy storage with 10-hour storage duration. By 2030, 1,460 MW of energy storage with 4-hour storage duration and 40 MW of energy storage with 10-hour storage duration are available.

- For offshore wind, 200 MW offshore wind in Lake Michigan was modeled with hourly profiles from NREL's WIND TOOLKIT for the historical years 2007-2013.

- For the SOO Green HVDC transmission line, 2,650 MW of wind in Iowa was modeled with hourly profiles from NREL's WIND TOOLKIT for the historical years 2007-2013; 1,850 MW of solar in Iowa was modeled with hourly profiles from NREL's National Solar Radiation Database for the historical years 2007-2013; and 650 MW of 4-hour energy storage was modeled. A transfer limit from Iowa to Illinois of 2,100 MW was also applied.

Transmission interface limits (import and export limits) between PJM and MISO regions are also included in the GE database. Interface transfer limits between MISO and PJM are based on the Northeast Power Coordinating Council's Long Range Adequacy Overview as well as the MISO Loss of Load Expectation Working Group.

What This Study Is – and What It Is Not

The Policy Study seeks to measure and quantify the anticipated marginal impacts from three discrete policy proposals. That process involves, first, determining a base case against which the introduction of a policy proposal can be modeled. Once that base case is established, one must next model the before and after cases, with the "after" reflecting the impacts of the underlying policy proposal. The

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measured differences then provide quantitative data and demonstrates the "potential impacts" of that proposal across the qualitative criteria flagged for analysis in Public Act 103-0580.

As with all such analyses, the uncertainty inherent in predicting impacts only expands as impacts are analyzed further into the future. Not only is the world we know constantly changing, but the world we expect is shifting dramatically as well: PJM latest load forecast issued in January 2024 now projects nearly a 40% increase in total energy use by 2039, driven in part by the growth in data centers, electric vehicle adoption, and other electrification initiatives. This 2024 updated load forecast substantially increased expected energy consumption relative to the 2023 forecasts used for Policy Study modeling—by about 14.5% on a net energy basis by 2038 and 12.6% for the ComEd zone over the same period. As both the SOO Green HVDC transmission line and the offshore wind project assume deployment near the end of the decade (energy storage projects may begin rolling out more quickly, but still require multi-year development timelines), the period across which the three policy proposals will demonstrate impacts is laced with uncertainty.

In presenting counterpoints to this Policy Study, others may choose to utilize a different snapshot of future conditions to further magnify the benefits of analyzed policies or to restate expected costs. These efforts should not be dismissed simply because they provide narrative support for that party's objectives, as doing so would assume that there are right or wrong answers. From our experience assembling this Study, one should instead assume that there are instead more or less justified choices, and we approached this analysis by making methodological choices that our team believes feature the strongest justification.

This Policy Study also seeks only to analyze the potential impacts of the three discrete legislative proposals selected for analysis through Public Act 103-0580. While comparative information about other approaches taken by different jurisdictions is provided in narrative form, modeling alternative approaches is both outside of the scope of Public Act 103-0580's directives to the IPA and not within our bandwidth while developing the Study within the directed timeline. Consequently, this Study is <u>not</u> an attempt at integrated resource planning, at comprehensive transmission expansion planning, or at devising the optimal mix of energy policies for the State. Further, this Study is not an effort at determining the optimal deployment level for a given technology, nor is it an effort to determine the optimal use of potential subsidy dollars across all possible uses. Instead, as directed by law, this Study is an effort to determine "before" and "after" snapshots demonstrating the potential impacts from three specific policy proposals across various criteria, with inputs in analysis—how much storage, how large of a transmission line, how large of an offshore wind project, and so forth—reflecting choices made through the proposals themselves (to the extent that those choices were clear).

Along those lines, only known and expected results from the policy proposals themselves were modeled and are presented as conclusions. While certain parties argued in comments about the benefits of jumpstarting an industry or spurring various indirect impacts, the IPA sought to model and quantify only that which it could credibly stand behind. In cases where the IPA felt that a benefit or cost could not be reliably measured—for example, the full suite of potential economic impacts resultant from a loss of load event— it was generally not included. This is <u>not</u> to say that such benefits or costs *do not exist*, but that quantification seemed too specious or speculative for the Agency to

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model and stand behind. Relatedly, external capital sources or support through other jurisdictional entities were folded into the analysis where such support was reasonably likely to occur (such as with qualification for a tax credit), but generally not if a future discretionary decision was required (such as receiving grant funding or offering to make community-development commitments).

We also sought to mirror the specific terminology used in the law while assessing impacts. For example, even if a party believes that a policy provides benefits to "disadvantaged communities," the IPA sought to analyze impacts to "environmental justice communities"—a term with a specific meaning under the IPA Act—as directed through Public Act 103-0580. But we recognize that benefits to a broader and geographically distinct array of "disadvantaged communities" may exist and could be important to policymakers. By heeding to statutory directives in analysis, the IPA is not intending to invalidate other lines of argument.

Lastly, this Study is not intended to preempt the pending resource adequacy report due to be developed by Illinois Environmental Protection Agency ("IEPA"), the Illinois Commerce Commission ("ICC"), and the IPA in 2025. Pursuant to Section 9.15(o) of the Illinois Environmental Protection Agency Act, the IEPA, IPA, and ICC must jointly prepare and release a report "that examines the State's current progress toward its renewable energy resource development goals, the status of CO2e and copollutant emissions reductions, the current status and progress toward developing and implementing green hydrogen technologies, the current and projected status of electric resource adequacy and reliability throughout the State for the period beginning 5 years ahead, and proposed solutions for any findings." The first such report is due to be released publicly no later than December 15, 2025. Should that report find that there are concerns related to sufficient resource adequacy or reliability, then the IPA and IEPA "shall develop a plan to reduce or delay CO2e and copollutant emissions reductions requirements only to the extent and for the duration necessary to meet the resource adequacy and reliability needs of the State" with that Plan then filed with and litigated before the ICC. Modeling assumptions and outputs from this Policy Study should not be viewed as precursors to conclusions from that analysis, as this Study requires simplifying assumptions to best measure the potential impacts of discrete policy proposals.

We genuinely hope that this Policy Study proves useful and informative as parties debate these and other energy policy options during the General Assembly's Spring 2024 legislative session and across the years to come.

Sincerely,

Brian P. Granahan

Acting Director, Illinois Power Agency

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Appendixes and associated workpapers are available at:

https://ipa.illinois.gov/ipa-policy-study/2024-policy-studies-appendices.html

Executive Summary

This Policy Study analyzes three policy proposals discussed during the Spring 2023 Legislative Session of the Illinois General Assembly—two of which were formally introduced as bills, and one of which has been discussed conceptually dating back to the negotiations on what ultimately became the Climate and Equitable Jobst Act (Public Act 102-0662) in 2021, and for which the Illinois Power Agency ("IPA" or "Agency") has obtained a draft bill. While none of these proposals passed out of either the Illinois House or Senate in 2023, during the Spring 2023 Legislative Session, the Illinois Senate introduced a third amendment to House Bill 3445 ("HB 3445") directing the Agency to commission and publish a Policy Study evaluating the potential impacts of these proposals on Illinois' decarbonization goals, the environment, grid reliability, carbon and other pollutant emissions, resource adequacy, long-term and short-term electric rates, environmental justice communities, jobs, and the economy. The schedule outlined in HB 3445 directed the Agency to publish an initial draft of the Policy Study for a 20-day public comment period and publish a final Policy Study no later than March 1, 2024.[1]

Though HB 3445 was never enacted, on November 2, 2023, Senate Bill 1699 ("SB 1699") was amended to include the text from HB 3445 directing the IPA to commission and publish the Policy Study. SB 1699 was signed into law on December 8, 2023, creating Public Act 103-0580. Consistent with Public Act 103-0580, the Agency has published this Policy Study to evaluate the potential impacts of these three proposals on Illinois' decarbonization goals, the environment, grid reliability, carbon and other pollutant emissions, resource adequacy, long-term and short-term electric rates, environmental justice communities, jobs, and the economy.

a) Policy Proposals

i) Energy Storage

The first proposal analyzed is Senate Bill 1587 ("SB 1587") and amendments to Senate Bill 1587 of the 103rd General Assembly filed prior to May 31, 2023, or a similar proposal for the deployment of energy storage systems supported by the State through the development of energy storage credit targets. If passed, the Agency would procure energy storage credits on behalf of Illinois electric utilities via a competitive energy storage procurement developed by the Agency. The energy storage credits would be procured from privately-owned, large-scale energy storage providers using energy storage contracts of at least 15-year durations. The energy storage procurement plan would be designed to enhance overall grid reliability, flexibility, and efficiency, and to lower electricity prices in Illinois. In addition to large-scale

[1] As January 21, 2024 was a Sunday, the Agency published the draft Policy Study on January 22, 2024 with a comment deadline of February 12, 2024 (which was later extended to February 26, 2024). This approach lengthened the time for feedback to 21 days (as opposed to 20 days) and shortened the time for revision of the plan to 19 days. Consistent with Public Act 103-0580, the Agency published the final Policy on March 1, 2024 and delivered copies to the Governor and members of the Illinois General Assembly, including policy recommendations for the General Assembly.

energy storage, the proposal also includes the creation of distribution level energy storage programs through utility tariffs as approved by the Illinois Commerce Commission: residential and commercial storage programs that would allow customer-sited batteries to provide grid benefits and cost-savings to ratepayers; and a community solar energy storage program intended to serve as a peak reduction program by utilizing community solar paired storage projects deployed daily in summer months during peak hours. This proposal is discussed in Chapter 5.

ii) Offshore Wind

The second proposal analyzed is House Bill 2132 ("HB 2132") of the 103rd General Assembly as it passed out of the House on March 24, 2023, or a similar pilot program proposes to establish one new utility-scale offshore wind project capable of producing at least 700,000 megawatt hours annually for at least 20 years in Lake Michigan. This proposed bill requires that the new utility-scale offshore wind project include an equity and inclusion plan to create job opportunities for underrepresented populations in addition to equity investment in eligible communities, and include a fully executed project labor agreement. This proposal is discussed in Chapter 6.

iii) High Voltage Transmission Line

Finally, the third proposal analyzed is a policy establishing renewable energy credits for a high voltage direct current transmission line bringing power from Iowa to Illinois. The proposal requires the Agency to procure long-term contracts (25 to 40 years duration) for the delivery of renewable energy credits on behalf of electric utilities in Illinois with at least 300,000 customers. The renewable energy credits would be delivered by a high voltage direct current transmission facility with more than 100 miles of underground transmission lines in this State capable of transmitting electricity at or above 525 kilovolts and delivering power into the PJM market (which the IPA understands to be the SOO Green HVDC Link project). This proposal is discussed in Chapter 7.

b) Policy Study Approach

Chapter 2 describes the State's Renewable Portfolio Standard and provides historical background on Illinois legislation that led to the policy proposals analyzed in this Policy Study, which were introduced during the Illinois General Assembly Spring 2023 legislative session. Chapter 2 also describes the Agency's process for developing this Policy Study, including receiving feedback from technical data requests from proponents of these three policies, as well as receiving broader information and additional perspectives from stakeholders on the policy areas being studied, including any data, information, reports, analyses, considerations, or other information which stakeholders believe should be brought to the IPA's attention for conducting a comprehensive and well-rounded analysis in the Policy Study.

Chapter 3 describes the legislative proposals that were introduced during the Illinois General Assembly's Spring 2023 legislative session including Senate Bill 1587 that would require the Agency to develop an energy storage procurement plan resulting in electric utilities contracting for energy storage credits from contracted storage systems; House Bill 2132 that would require the Agency to develop a procurement process to procure at least 700,000 renewable energy credits, delivered annually for at least 20 years, from one new utility-scale offshore wind project in Lake Michigan; and a policy requiring the Agency to procure high voltage direct current ("HVDC") renewable energy credits related to an HVDC.

Chapter 4 describes the Agency's process using its Planning and Procurement Consultant, Levitan and Associates ("Levitan") and subcontractors, ENTRUST Solutions Group and GE Energy Consulting, for conducting the modeling and analytical work necessary to support the Policy Study. Full reports of each modeling exercise are available as Appendices B to E of the Policy Study, and Chapter 8 provides an overview of the methodology used for each.

Levitan's modeling and analytical work for the Policy Study included using Aurora, a production cost simulation model that is widely used in the power industry. Aurora assesses the policy proposals' impacts on wholesale electricity prices, emissions, and changes to the composition and operation of the generation resource mix in Illinois. Levitan also used IMPLAN economic modeling to evaluate the policy proposals' impacts on the State's employment and the State's economy. IMPLAN estimates the relationship between a given set of demands for final goods and services and the inputs required to satisfy those demands by tracking industry production and domestic consumption, such as household spending.

ENTRUST Solutions Group used Siemens PTI PSS®E and PowerGEM TARA, steady-state power flow software tools which are widely used by transmission organizations and are a critical part of several production tool chains for transmission planning and operations in the U.S., to evaluate the impacts on transmission reliability and grid resilience; and used power flow modeling to evaluate the impacts on grid reliability. Siemens PTI PSS®E and PowerGEM TARA use power flow analysis to analyze a power system in normal steady-state operation, then simulate scenarios that could adversely affect the operation of the system to identify potential contingencies that could be caused by the interconnection of the resources associated with each of the three policy proposals in the Policy Study.

GE Energy Consulting utilized industry standard modeling tools including GE's Multi-Area Reliability Simulation ("GE MARS") to evaluate the proposals' impacts on generation reliability and resource adequacy—the ability of an electric power system to meet demand for electricity—in the years 2030 and 2040. The GE MARS simulation included load forecast uncertainties, transmission outages, equipment failures that would interrupt transmission or generation, and variable renewable generation operations such as when the wind stops blowing unexpectedly.

c) Modeling Results

i) Energy Storage Development

The modeling results for energy storage, as proposed in SB 1587, suggest that the proposed storage would have a positive impact on Illinois' generation reliability and resource adequacy; would increase transmission reliability and grid resilience; would lower wholesale energy costs; would avoid emissions from fossil fuel combustion; and would positively impact the State's economy and lead to job creation.

The deployment of 7,500 MW of utility-scale energy storage was modeled to demonstrate the impacts on generation reliability, resource adequacy, transmission reliability, and grid resilience. The loss of load expectation ("LOLE") industry standard is 0.1 days/year (or one day in ten years).[2] The modeling results showed that compared to that base case level of 0.1, by 2030 when the storage would not yet be fully deployed, the LOLE for the modeled level of energy storage would drop to 0.01. By 2040, when the 7,500 MW of utility-scale energy storage is modeled to be fully deployed, the LOLE is expected drop to 0.0 versus the 0.1 days/year modeling baseline.

Regarding transmission reliability and grid resilience, modeling results showed that as generation resources are added to the grid, existing overloaded grid conditions or constraints can increase, and new overloads or constraints can develop. The analysis conducted for this policy study identified likely transmission upgrades that would be needed to support additional generation resources, with estimated upgrade costs in MISO and PJM illustrated in Table 5-7 and Table 5-8. The estimated cost of transmission upgrades in MISO ranges from $6,450 to $818,067 per MW of added storage capacity in MISO and $49,125 to $3,864,091 in PJM. Actual costs can only be determined by the completion of full interconnection studies by the applicable RTO.

8,500 MW of energy storage (7,500 MW of utility-scale projects on the transmission system and 1,000 MW of distributed projects paired with solar systems) were used to model impacts on energy costs, the economy, job creation, and emissions.

The proposed 7,500 MW of utility-scale energy storage development projects would impact Illinois electricity costs in two ways: (i) based on estimates of the revenue the projects would receive from capacity and energy sales, the study estimates a net shortfall of $239.1 million per year—this amount would be the annualized cost that would be supported by Illinois ratepayers through the purchase of energy storage credits; and (ii) the storage projects would benefit Illinois ratepayers by lowering wholesale energy costs by $739.1 million over 20 years, or $22.6 million on an annualized basis in real 2022 dollars. Deploying 1,000 MW

[2] LOLE determines the numbers of days in which a loss of load (i.e., a power outage/disconnection) would be expected to occur on average across variety of system conditions. LOLE of 0.1 days/year is a de-facto standard, or criteria, in industry for probabilistic reliability metrics, sometimes referred to as "1 day in 10 years". The criteria of 0.1 days/year LOLE is used as the starting point for analysis of LOLE improvement to allow the impacts to reliability of different resources to be comparable. By using the criteria of a LOLE of 0.1 days/year for this analysis, it shows how each policy improves the reliability of the Illinois system if the system's reliability is at "criteria" (LOLE of 0.1 days/year).

of distributed energy storage would have an annualized cost of $82.2 million, while contributing $4.0 million in lowering wholesale electricity costs.[3]

For the average Ameren residential customer, the modeling indicates that the monthly bill impact from 2030-2040 of implementing the energy storage policy would be $2.88 in nominal dollars and $1.89 in real 2022 dollars. For the average ComEd customer the impact would be $1.85 in nominal dollars and $1.21 in 2022 real dollars. The difference is due to the lower average consumption of ComEd customers compared to Ameren customers. For more information on these comparisons, see Section 8.d.ix.

While avoided emissions from the combustion of fossil fuels, including particulate matter, sulfur dioxide, and nitrogen oxides is uncertain, a range of potential estimates of the monetized value of the avoided emissions from the proposed energy storage projects over the 20-year period is in the range of $531 million to $4.8 billion in 2022 real dollars as shown in Table 5-11.

The introduction of storage resources had a significant impact on the dispatch of ZEFs. Storage reduced the output of ZEFs by 63%. The introduction of storage resources also effectively "idled" approximately 2,100 MW of ZEF capacity that was included in the base case. The idled units had zero output in the second half of the study period (2040-2049) in the Storage case.[4]

Further, IMPLAN modeling estimated the economic impacts from proposed energy storage on employment, labor income, value added, and output. Employment is the number of jobs associated with economic activity and is expressed as 2,080-hour Full Time Equivalent ("FTE")-years. For example, an employment impact of one is equal to a single person working 2,080 hours. Labor income is all forms of employment income, including employee compensation—wages and benefits—and proprietor income. Value added is the difference between an industry's or establishment's total output and the cost of its intermediate inputs—it is a measure of the contribution to GDP. Output is the value of industry production, including the cost of its intermediate inputs. The energy storage modeled was for two scenarios (i) deployment of 7,500 MW of utility-scale energy storage; and (ii) deployment of 1,000 MW of distributed storage (200 MW for residential projects and 800 MW for commercial or community solar projects). The inputs for capital and operating expenditures are higher for distributed storage due to higher equipment and labor costs for smaller scale systems. While not definitive, the IMPLAN modeling found that of the three policies studied, the energy storage projects would have the largest impact in terms of dollars of value added

[3] The costs and emissions reduction results presented in this section have been revised from the draft Policy Study to reflect several corrections in modeling. The most significant revisions include those described in the Agency's February 8 errata that updated the reporting of energy revenue, and revisions made after receiving comments on the draft Policy Study that include updating retirement schedules for certain plants, adopting an adjustment to the capacity price for the ComEd zone, and including the investment tax credit for the proposed offshore wind project. For details on those corrections please see Section 8.d.i.

[4] ZEFs are Zero Emissions Fuel units included in the Aurora production cost modeling to establish the base case that policy scenarios are compared against. ZEFs are called upon sparingly in the Aurora production cost modeling but are critical during stressed system conditions. 8.5 GW of ZEFs are included in the modeling. See Section 8.d.v for more details on the use of ZEFs.

and employment, with the total employment associated with the utility scale and distributed storage cases taken together ranging from 32,417 FTE-years to 115,329 FTE-years and the total value-added impact ranging from $3.9 billion to $16.3 billion. While the modeling did not specifically address the way in which the employment and total value-added impacts would be distributed in Illinois, several observations can be drawn from the modeling results—the utility-scale storage and distributed storage impacts are likely to be spread around the State but would be concentrated in MISO Zone 4, where most of the ESS queue locations modeled are located, and in the high capital and operating expenditure cases where the battery cell manufacturing facilities would be located.

Finally, the modeling suggests that the economic and employment impacts associated with the high capital and operating expenditure storage cases may offer support for policies designed to encourage battery manufacturers to locate new manufacturing and assembly facilities in Illinois.

ii) Offshore Wind in Lake Michigan

The modeling for the offshore wind project proposed in HB 2132 suggests that the project would have minimal impacts on generation reliability and resource adequacy in Illinois; would not have a significant impact on grid resiliency; would increase the State's RPS rate impact cap and reduce wholesale energy costs; would avoid emissions from fossil fuel combustion; and would positively impact the State's economy.

The modeling of the offshore wind project showed that in both 2030 and 2040, LOLE would decrease from a base case of 0.1 to 0.09, which is a much smaller impact than seen by the energy storage and HVDC transmission line policies that were also studied. The proposed offshore wind project's small impact on generation reliability and resource adequacy is likely due to the project's size of 200 MW. Additionally, the modeling showed the Effective Load Carrying Capability ("ELCC")—which measures the resource's ability to produce electricity when the grid is most likely to experience an electricity shortage and is expressed as a percentage of a resource's total capacity—for of the offshore wind project would be 29% in 2030 and 20% in 2040.

Regarding transmission reliability and grid resilience of offshore wind, five different potential interconnection points in the Lake Calumet area of Chicago were studied.[5] The five points do not differ greatly in projected interconnection costs, and these costs are generally significantly higher than the projected cost per megawatt to interconnect the SOO Green HVDC transmission line or utility-scale energy storage projects, and do not provide a significant improvement of grid resilience.

Modeling of the proposed offshore wind project's impacts on electricity costs showed that the project would impact electricity prices in several ways: (i) HB 2132 would authorize an increase in the RPS rate impact cap from 4.25% to 4.5% which is roughly equivalent to $33-

[5] For additional details on these potential interconnection points, please see Appendix B.

$34 million per year; (ii) the revenue the project would receive from capacity and energy sales, and the sale of RECs, would be less than what is required to support the project, with a projected annualized shortfall (in 2022 dollars) of $10.6 million. This suggests that for the project to be viable, the proposed increase in the RPS rate impact cap may not be quite sufficient to support the project and a higher level might be required to support the project's development; and (iii) the project would benefit ratepayers by impacting wholesale energy costs, lowering those costs for Illinois ratepayers by $301.6 million over 20 years, or $8.9 million on an annualized cost in 2022 dollars.[6]

For the average Ameren residential customer, the modeling indicates that the monthly bill impact from 2030-2040 of implementing the offshore wind policy would be $0.39 in nominal dollars and $0.25 in real 2022 dollars. For the average ComEd customer the impact would be $0.25 in nominal dollars and $0.16 in 2022 real dollars. The difference is due to the lower average consumption of ComEd customers compared to Ameren customers. For more information on these comparisons, see Section 8.d.ix.

While avoided emissions from the combustion of fossil fuels, including particulate matter, sulfur dioxide, and nitrogen oxides is uncertain, a range of potential estimates of the monetized value of the avoided emissions from the proposed offshore wind projects over the 20-year period is in the range of $115 million to $1.1 billion as shown in Table 6-5.

Lastly, IMPLAN modeling of the offshore wind project's economic impacts and job creation estimates that the project could create 764 to 1,893 FTE-years with total value added impacts in the range of $97.8 million to $265.1 million.

iii) SOO Green HVDC Transmission Line

The modeling for the proposed SOO Green HVDC transmission line suggests that the line would positively impact generation reliability and resource adequacy (although uncertainty remains regarding its recognition as a capacity resource and eventual accreditation);that transmission system upgrades for the HVDC transmission line would likely be needed to ensure reliability and grid resilience; that the HVDC transmission line would lower wholesale energy costs and avoid emissions from fossil fuel combustion; and that the HVDC transmission line would positively impact the State's economy and lead to job creation.

Regarding generation reliability and resource adequacy, the modeling shows that the proposed SOO Green transmission line would reduce the LOLE from the base case level of 0.1 to 0 in 2030 and to 0.01 in 2040. Similarly, based on the profile of generating facilities submitted by SOO Green, the modeled ELCC for SOO Green would be 96% in 2030 and 92% in 2040, indicating that a significant portion of the energy delivered by SOO Green would

[6] The costs and emissions reduction results presented in this section have been revised from the draft Policy Study to reflect several corrections in modeling. The most significant revisions include those described in the Agency's February 8 errata that updated the reporting of energy revenue, and revisions made after receiving comments on the draft Policy Study that include updating retirement schedules for certain plants, adopting an adjustment to the capacity price for the ComEd zone, and including the investment tax credit for the proposed offshore wind project. For details on those corrections please see Section 8.d.i.

contribute to generation and resource adequacy. The modeling also showed that, for transmission reliability and grid resilience, transmission system upgrades would be needed, however, the actual costs these upgrades can only be determined by the completion of full interconnection studies by the applicable RTO (PJM).

Further, the proposed SOO Green Line would impact electricity prices in two ways: (i) based on the estimate of the revenue the project would receive from capacity and energy sales, and an estimated strike price of $115.39/MWh, the study estimates a $430.7 million per year difference—this amount would be the annualized cost (revenue shortfall) that would be supported by Illinois ratepayers through the purchase of RECs from the project; and (ii) the project would benefit ratepayers by impacting wholesale energy costs, lowering those costs for Illinois ratepayers by $5.85 billion over 20 years, or $178.3 million on an annualized cost in 2022 dollars.[7]

For the average Ameren residential customer, the modeling indicates that the monthly bill impact from 2030-2040 of implementing the high voltage direct current transmission line policy would be $4.99 in nominal dollars and $3.42 in real 2022 dollars. For the average ComEd customer the impact would be $3.21 in nominal dollars and $2.20 in 2022 real dollars. The difference is due to the lower average consumption of ComEd customers compared to Ameren customers. For more information on these comparisons, see Section 8.d.ix.

The introduction of SOO Green had a significant impact on the dispatch of ZEFs. SOO Green reduced the output of ZEFs by 29%. The introduction of SOO Green also effectively "idled" approximately 700 MW of ZEF capacity that was included in the base case.[8]

While avoided emissions from the combustion of fossil fuels, including particulate matter, sulfur dioxide, and nitrogen oxides is uncertain, a range of potential estimates of the monetized value of the avoided emissions from SOO Green over the 20-year period is in the range of $2.5 billion to $23.7 billion as shown in Table 7-8.

Lastly, the proposed HVDC transmission line could provide economic impacts in Illinois of 3,470 FTE-years and total value added of $414.5 million. In contrast, according to filings made by SOO Green before the Iowa Utilities Board, the project would create $663 million in capital expenditures in Iowa and 5,439 FTE-years in job creation for the construction of the line. In addition, according to SOO Green's filing the development of the renewable resources

[7] The costs and emissions reduction results presented in this section have been revised from the draft Policy Study to reflect several corrections in modeling. The most significant revisions include those described in the Agency's February 8 errata that updated the reporting of energy revenue, and revisions made after receiving comments on the draft Policy Study that include updating retirement schedules for certain plants, adopting an adjustment to the capacity price for the ComEd zone, and including the investment tax credit for the proposed offshore wind project. For details on those corrections please see Section 8.d.i..

[8] ZEFs are Zero Emissions Fuel units included in the Aurora production cost modeling to establish the base case that policy scenarios are compared against. ZEFs are called upon sparingly in the Aurora production cost modeling but are critical during stressed system conditions. 8.5 GW of ZEFs are included in the modeling. See Section 8.d.v for more details on the use of ZEFs.

in Iowa that would supply the line would create an additional $1.3 billion to 1.6 billion in wages and an additional 19,683 and 24,030 FTE-years.

d) Recommendations

Chapter 9 provides policy recommendations that Illinois Power Agency has developed for the General Assembly to consider regarding the three proposed policies.

These recommendations include:

i) General Recommendations

The Agency's recommendations include general recommendations such as considering how market volatility could impact project developers and Illinois ratepayers; ensuring developed policies include the equity and labor standards outlined in CEJA; accounting for flexibility in procurements under each of the three proposed policies; and ensuring the policies are planned in conjunction with other initiatives focused on Illinois' transition to a decarbonized, clean energy economy.

ii) Energy Storage

The Agency's recommendations specific to energy storage policy include ensuring that the Agency has flexibility to determine and adjust energy storage procurement goals in a manner necessary for supporting Illinois' clean energy goals; authorizing a dedicated program modeled from the Illinois Solar for All Program to support storage for income-eligible customers and customers residing in environmental justice communities; ensuring that the incentives from an Energy Storage Tariff Credit are calibrated with the smart inverter rebate for storage to ensure that the total compensation received by customers is appropriate; exploring opportunities for long-duration energy storage systems; considering initial forward procurements; and adopting requirements for storage valuation.

iii) Offshore Wind

The Agency's recommendations specific to an offshore wind policy include analyzing and factoring in in similar challenges faced by other states with offshore wind project cancellations; requiring robust information on project economics before authorizing a procurement event; considering federal funding application status for port development and construction when approving procurements to support an offshore wind project; adopting the recommendations of the Lake Michigan Offshore Wind Advisory Report that clarify securing rights to the lakebed for offshore wind development; thoroughly reviewing environmental impacts of offshore wind that may require further review by other agencies; authorizing and funding additional research on the geophysical characteristics of the potential areas for wind development; and requiring additional information on the offshore wind project interconnection point and associated site improvements as a prerequisite condition for a contract award.

iv) High Voltage Transmission Line

The Agency's recommendations specific to a policy supporting an HVDC transmission line include requiring additional information from SOO Green regarding the renewable energy resources that will supply the HVDC transmission line prior to obtaining approval of public support for the line; requiring equity commitments to both the SOO Green HVDC transmission line construction and to any renewable energy development in Iowa for projects producing RECs paid for by Illinois ratepayers; ensuring any unresolved capacity market participation issues for SOO Green are satisfactorily resolved prior to committing ratepayer funds to support the project; considering the timing of cost recovery to support the SOO Green HVDC transmission line, and in the alternative, consider if collections should not begin until a later date in order to decrease the short-term rate impacts to Illinois ratepayers; and creating a different system for managing maximum bid prices and determining the level of public financial support for the HVDC transmission line

Please refer to Chapter 9 for more detailed discussion of these recommendations.

1) Introduction

a) Purpose of the Policy Study

This Policy Study has been prepared pursuant to Section 1-129 of the Illinois Power Agency Act ("IPA Act"). Section 1-129 of the IPA Act was established through Public Act 103-0580 which signed into law by Governor Pritzker on December 8, 2023. Through this new section, the Illinois General Assembly requested the Illinois Power Agency ("IPA" or "Agency") to examine three proposals considered by the General Assembly in the Spring of 2023: a procurement to support the development of a proposed utility-scale offshore wind project, energy storage procurements and programs, and the proposed development of a high-voltage direct current transmission line that would bring renewable energy from northern Iowa into Illinois. The Agency's examination includes analysis and in-depth background research for each proposal, technical modeling of a range of impacts of each proposal, and the IPA's recommendations for the General Assembly as it considers future legislation on these topics.

The IPA developed a draft Policy Study and released it for stakeholder feedback on January 22, 2024. That stakeholder feedback was due on February 12, 2024. The Agency subsequently released an errata announcement on February 8, 2024 and on February 13, 2024 granted stakeholders additional time to comment on 1) the corrections made via that errata and as 2) additional workpapers released by February 16, 2024. Twenty-three stakeholders provided comments by February 12, 2024. Three of those stakeholders provided supplemental comments, and two additional stakeholders provided comments by the extended deadline of February 26, 2024.[9]

The Agency considered the feedback received and revised the draft Policy Study accordingly. On March 1, 2024, the Agency submitted a final version of the Policy Study to the Governor and General Assembly.[10]

b) Policy Study Structure

This Policy Study is organized into the following chapters:

- An Executive Study that provides key highlights of the Policy Study
- Chapter 1 is this Introduction that provides background on the Illinois Power Agency and the Illinois energy market
- Chapter 2 provides more details on the background and purpose of this Policy Study
- Chapter 3 outlines the specific legislative proposals examined in this Policy Study
- Chapter 4 describes the methodology used for the Policy Study
- Chapter 5 provides background and research on energy storage

[9] Section 2.c.ii contains additional information on the stakeholder comments received.

[10] Copies of the draft and final Policy Study, appendices, workpapers, stakeholder comments, and announcements are available on the Agency's Policy Study webpage: https://ipa.illinois.gov/ipa-policy-study.html.

- Chapter 6 provides background and research on offshore wind
- Chapter 7 provides background and research on high-voltage direct current transmission lines
- Chapter 8 provides a summary of the technical analyses conducted, with full reports provided as Appendices B-E and supplemental workpapers
- Chapter 9 contains recommendations to the General Assembly

c) The Illinois Power Agency

The Illinois Power Agency is an independent state agency established under Illinois law in 2007 through the enactment of the IPA Act (20 ILCS 3855). The IPA is charged with preparing annual electricity procurement plans and managing power procurement for residential and small commercial customers of Illinois electric utilities who have not switched suppliers. The IPA is also responsible for the implementation of the Illinois Renewable Portfolio Standard ("RPS"), a public policy designed to drive the development of renewables in Illinois, and other vital energy policy initiatives.

The Agency is under the oversight of the Executive Ethics Commission and is committed to:

- Ensuring that the process of power procurement is conducted in an ethical and transparent fashion, immune from improper influence.
- Conducting competitive procurement processes to procure the supply resources identified in procurement plans.
- Operating in a structurally insulated, independent, and transparent fashion so that nothing impedes its mission to secure power at the best prices the market will bear, provided that it meets all applicable legal requirements.
- Continuing to review its policies and practices to determine how best to meet its mission of providing the lowest cost power to the greatest number of people, at any given point in time, in accordance with applicable law.

The primary activities of the IPA are:

- Developing annual electricity procurement plans to ensure adequate, reliable, affordable, efficient, and environmentally sustainable electric service at the lowest total cost over time, taking into account any benefits of price stability, for residential and small commercial customers of Ameren, ComEd, and MidAmerican. The Agency then conducts competitive procurement processes to procure the supply resources identified in its annual electricity procurement plans.
- Developing biennial Long-Term Renewable Resources Procurement Plans and implementing the programs and procurements contained in the Plans. This includes:
    - Competitive procurements to support the development of utility-scale wind, utility-scale solar, and brownfield site photovoltaic projects
    - The Illinois Shines Program to support the development of solar for individual homes and businesses, and the development of community solar projects

  - The Illinois Solar for All Program to support the development of solar for income-eligible households and communities
  - A large customer self-direct program through which large electric customers are eligible for bill credits through the self-directed procurement of renewable energy credits
  - Consumer protection requirements applicable to IPA incentive programs
  - The Minimum Equity Standard to increase access to the growing clean energy economy and ensure that the clean energy workforce is made up of a level of equity-eligible persons that increases over time
- Developing and administering the Carbon Mitigation Credit Procurement process and the Zero Emission Standard Procurement Plan, both of which support at-risk nuclear plants.

In January 2015, in response to a request from the Illinois General Assembly (House Resolution 1146), the Agency, along with the Illinois Commerce Commission, the Illinois Environmental Protection Agency, and the Department of Commerce and Economic Opportunity, published a set of reports on the impacts of premature closure of nuclear plants. The Agency's report was focused on what would be the impacts on reliability and capacity in the Midwest.[11]

Those reports bear some similarity to this Policy Study in that in 2014, the General Assembly requested that state agencies conduct detailed technical analyses of a complex policy issue and provide recommendations that could become a roadmap for future legislation to prevent the closure of at-risk nuclear plants. The Future Energy Jobs Act (Public Act 99-0906, also known as "FEJA") passed in December 2016 and included provisions that for the IPA to develop and implement a Zero Emissions Standard Plan that provided support to two at-risk nuclear plants. Subsequently, the Climate and Equitable Jobs Act (Public Act 102-0662, also known as "CEJA"), enacted in September 2021, included provisions for the IPA to develop and implement a Carbon Mitigation Credit Procurement Plan to provide support to three additional nuclear plants.

The Agency hopes that the General Assembly and other stakeholders will be able to utilize this Policy Study in a similar way, and that it will provide helpful information and recommendations to guide key policy decisions that are important for consideration as Illinois moves forward with its ambitious and nationally leading energy policy goals to create a clean energy future.

d) Key Dynamics of the Illinois Electricity Market

Through a series of legislative actions, notably FEJA and CEJA, Illinois has developed a robust set of policies to support the transition to clean energy. However, those policies need to be considered in the context of several key dynamics of the Illinois electricity market. For example, these dynamics are important in understanding how the structure of policy

[11] See: https://www.icc.illinois.gov/programs/Potential-Nuclear-Plant-Closing-in-Illinois for the reports.

initiatives from other states could be considered for Illinois, and what changes or accommodations would need to be made.

First, through a process that started with the Electric Service Customer Choice and Rate Relief Law of 1997 (Public Act 90-0561), Illinois restructured its electricity market.[12] This means that electric utilities in Illinois no longer own power plants, and electricity customers may choose their electric supplier. While the distribution of electricity remains regulated by the Illinois Commerce Commission, there is no longer a centralized planning process for developing new generation. Instead, such development must be privately funded, although the State's RPS does provide support for renewable energy project development through purchasing renewable energy credits generated by those projects. Unlike states that retained a vertically integrated regulatory framework for electric utilities, there is not a mechanism through regulatory processes to provide rate recovery to fund projects such as those included in the proposals being examined in this Policy Study.

To the extent that the IPA oversees the procurement of electricity, that procurement is only for a portion of Illinois customers—the residential and small commercial customers who do not purchase electricity from an Alternative Retail Electric Supplier ("ARES"). This portion of the market is only about 20-25% of the electricity load of the State. An implication of this is that policies that would seek to create long-term purchases of electricity through IPA-administered procurements to support a specific policy outcome would have limits in their scope and applicability. If the price of electricity procured through IPA-administered procurements for that portion of Illinois customers were to become significantly higher than the market price of electricity due to the enactment of new policies, this could create the risk of increased customer migration to ARES which would shrink the base of customers supporting those polices and would further increase the price of electricity procured by the IPA.

Second, Illinois is a net exporter of electricity and features a baseload of nuclear generation that provides a source of zero carbon electricity generation. In 2022, 53.4% of the electricity generated in Illinois came from nuclear generation, and that generation would cover 73% of the electricity consumed in the State. The other primary source of electricity generation in Illinois is coal, which produced 21.9% of the electricity generated in Illinois in 2022. Illinois has seen significant retirement of coal plants in recent years and provisions of CEJA are expected to phase out coal and natural gas in Illinois by 2045. While two natural gas power plants have opened in the past two years, new generation being developed in Illinois is likely to be renewable resources such as wind, solar, or hydroelectric resources. These projects will be developed by private companies who would sell power into wholesale markets, bid that power into IPA-administered electricity procurements, or find private off-takers. These projects might also participate in IPA-administered procurements for renewable energy

[12] Restructuring largely did not impact the municipal electric utilities and rural electric cooperatives in Illinois. Collectively they serve less than 10% of the load of the state.

credits but could also sell their renewable energy credits to private companies or into other states' RPS markets.

Third, Illinois is located in two separate Regional Transmission Organizations ("RTOs"), PJM and MISO. There are several impacts of this bifurcation of the State. For example, resource adequacy concerns are higher in MISO than in PJM due to the pace of retirement of coal (and to a lesser extent, natural gas) power plants compared to the development of new resources, expected to be largely wind and solar. The capacity market designs between the two RTOs are also very different, with the MISO capacity market being a short-term market that is more subject to large price fluctuation than the PJM market.[13] As a result, polices being considered could have very different impacts in the two RTOs as the value of capacity could vary significantly, which would impact project economics. Further, the process of approving interconnection agreements is also different for the two RTOs. While recent Federal Energy Regulatory Commission ("FERC") orders and other actions may help alleviate the delays in interconnection studies and approvals, project development timelines in different parts of the State may be impacted by those differences.

Fourth, the Illinois RPS has had great success since it was substantially updated in 2016 through FEJA, supporting 2,223 MW of new wind resources, and 4,775 MW of new solar resources in Illinois.[14] However, RPS funding has faced several challenges. One impetus for the passage of FEJA was limitation in the original RPS design, which created year-to-year funding uncertainty as customers moved between default supply service and ARES service. Additionally, the original RPS design focused on procuring renewable energy credits from existing projects rather than supporting development of new renewable energy projects. While this challenge was addressed through FEJA by consolidating RPS funding, a new challenge was inadvertently created through a bottleneck in the timing of when funding would be available. That bottleneck was exacerbated by COVID-19 creating significant delays in project development.

CEJA addressed that bottleneck by creating more flexibility in the timing of how funding could be used, as well as by increasing the amount of funding collected each year from ratepayers. However, CEJA also introduced a new mechanism for procuring RECs from utility-scale wind and solar projects that includes a price indexed to the price of electricity. This mechanism created a new type of funding uncertainty in that future costs cannot be predicted, and if energy prices decline, the price paid for RECs will increase and this could lead to funding shortfalls.[15] While the Agency expects that this can be solved through future legislative actions, for the purpose of this Policy Study, the Agency highlights the challenges inherent in developing new initiatives and the complex issues that need to be considered to ensure that the mechanisms to implement new policies function as intended.

[13] Capacity markets provide compensation to generators to ensure that they will be available during peak demand times.
[14] This includes projects that have been completed and those under development.
[15] For more discussion of this challenge see Chapter 5 of the IPA's pending 2024 Long-Term Renewable Resources Procurement Plan, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2024-long-term-plan-20-oct-2023-.pdf

2) Background/Purpose of IPA Policy Study

a) Overview of Previous Legislation and Spring 2023 Legislative Session

i) Origin and Initial Structure of the Illinois Renewable Portfolio Standard

Each proposal discussed in this Policy Study contains overlap with the approaches used by and the goals inherent in the Illinois Renewable Portfolio Standard ("RPS"). Therefore, background on the State's RPS, its evolution, its challenges in supporting successful project development, and current gaps in the RPS's approach to support new projects is necessary.

In 2007, the Illinois General Assembly established the State's RPS through Public Act 95-0481. The Act established the IPA Act, and through Section 1-75(c)(1) of the Act, the initial RPS established a goal of "25% by 2025" – that 25% of electricity consumption would be met with renewables through the procurement of renewable energy credits ("RECs") by 2025 – with carveouts for specific technologies later added to the RPS goals.[16] The Agency's annual procurement plans (developed primarily to propose procurements to meet the energy, capacity, and other standard wholesale product requirements of eligible retail customers) were required to include procurement proposals intended to meet annually-climbing, percentage-based renewable energy resource targets building toward 25% by 2025.

As with block energy procured by the Agency, the applicable electric utility served as the counterparty to resulting REC delivery contracts. Purchases of RECs would be paid for using ratepayer collections made by that utility, and RECs would be retired by that utility to demonstrate a share of load being met through renewable energy. Funds available for use under RPS contracts were subject to a rate impact cap—a fixed bill impact cap percentage (2.015% of 2007 rates)—which was then applied to eligible retail customer load to produce a renewable resources procurement budget.

Illinois is a restructured state, and approximately 70%-80% of load is met through competitive suppliers—and not the default electric utility supply met through Illinois Power Agency ("IPA" or "Agency") planning and procurements. Initially the State's annual RPS goals were calculated applicable only to "eligible retail load," which is the load of residential and small commercial customers receiving fixed price bundled service from their utility instead of service from an Alternative Retail Electric Supplier ("ARES") or real-time pricing. A separate compliance mechanism was later established for alternative retail electric suppliers whereby each ARES carried a percentage based RPS requirement as a percentage of its sales, similar to the Section 1-75(c) requirement, but the supplier could satisfy its obligation by making alternative compliance payments at a rate reflecting the rate paid by eligible retail customers for no less than 50% of its obligation. For the remaining 50% of its obligation, the ARES could either pay additional alternative compliance payments and/or self-procure RECs (with a requirement that any RECs procured for compliance be produced by facilities within

[16] RECs are certificates that represent the environmental benefits of electricity generated from renewable energy generation. One REC is the equivalent of one megawatt-hour (1,000 kilowatt-hours) of electricity produced by a renewable energy project.

the regional transmission territories of PJM Interconnection, L.L.C. ("PJM") and Midcontinent Independent System Operator, Inc. ("MISO"), a relatively broad geographic footprint).

At least two features of this model are necessary to understand in assessing the proposals analyzed in this study: first, dating back to 2007, the approach Illinois has taken to support the development of renewables has involved the procurement of RECs—the intangible environmental attributes of generation from a renewable energy project, decoupled from the energy itself—with the project owner/operator recovering revenues for the sale of RECs to support project development with those RECs then retired to help gauge the share of electricity met through renewables. With the exception of tariff changes proposed in Senate Bill 1587 ("SB 1587") used to support small-scale and behind-the-meter storage project development, each of the three proposals discussed herein relies on a similar system through which revenues used to support the underlying project are routed to the project's owner or operator through a) ratepayer collections, b) paid out by a utility on a contract basis through a long-term contract, c) to that project's owner or operator, and d) as consideration for intangible attributes ("credits") associated with that project.[17]

Second, as a restructured state, Illinois has generally <u>not</u> utilized state-administered power purchase agreements through which energy is purchased to meet customer load as a means for supporting new renewable energy project development.[18] One exception was what are known as the 2010 Long-Term Power Purchase Agreements ("LTPPAs") used to support new utility-scale wind and solar projects; these contracts were bundled (RECs <u>and</u> energy) 20-year agreements through which projects sold RECs and energy to Illinois electric utilities, with revenues received back for those sales used to support project development. As the IPA is not legally authorized to procure energy on behalf of competitive suppliers, energy procured under these contracts has been used to meet "eligible retail customer" supply requirements—an approach that was legally sustainable when the IPA's planning and procurement for energy and RECs had direct overlap (as both were only for eligible retail customer supply needs).[19]

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[17] This same structural approach is also taken to support the continued operation of nuclear plants under the state's Zero Emission Standard and Carbon Mitigation Credit procurement process.

[18] The IPA Act has now dormant provisions to support the development of clean coal facilities through sourcing agreements which are functionally similar to power purchase agreements. This approach was used for FutureGen 2.0, a clean coal repowering program and carbon dioxide storage network that would have been located in Meredosia, Illinois and was designed to capture more than 90% of the coal plant's annual carbon emissions by using oxy-combustion technology. However, U.S. DOE funding support for FutureGen 2.0 was suspended, and in early 2016, the project's development was ultimately terminated. The Illinois Competitive Energy Association and Illinois Industrial Energy Consumers had challenged the ICC's approval of the sourcing agreements over the constitutionality of binding Alternative Retail Electric Suppliers to those sourcing agreements in addition to Ameren and ComEd. The case was vacated by the Illinois Supreme Court as moot after the project was terminated so the underling challenge was never fully resolved (See: Commonwealth Edison Co. v. Ill. Commerce Comm'n, 2016 IL 118129.)

[19] While meeting supply requirements through long-term contracts used to support new project development may not pose major challenges at smaller quantities, larger shares of default supply being met through long-term contracts carries substantial risk. If long-term contract prices end up well above available market electricity prices, the share of customers taking fixed price default supply service may decline substantially (as competitive suppliers would be able to offer more competitive electric supply rates) due to customer migration from default supply service, causing the costs of above-market contracts to be socialized across an increasingly smaller whole (a situation colloquially referred to as a "death spiral"). Additionally, as only residential and small commercial customers are eligible for default supply, this approach socializes costs of new project development only across the smallest customers.

The LTPPAs are also a case study in the flaws of the initial RPS structure. As the annual renewable resources budget declined due to customer load moving to ARES supply via municipal aggregation (as collections were only made from eligible retail customers, and thus *not* from customers of ARES), not only was funding unavailable to conduct additional renewable energy resource procurements, but funding was also no longer available to meet the full commitments of the LTPPAs. As a result, for two years ComEd's LTPPAs were "curtailed" (payment was not made through the renewable resources budget for the full expected output). Due to the unpredictability of available budgets in future years, the Agency's annual procurement plans after the 2010 LTPPAs proposed only the procurement of one-year contracts to meet each upcoming delivery year's renewable energy resource obligations should funds be available— this resulted in a "broken RPS," as collected funds could not be leveraged for the long-term contracts offering revenue certainty necessary to support new project development.

ii) Future Energy Jobs Act ("FEJA") in 2017

This need to "fix" a "broken RPS" in part led to Public Act 99-0906, also known as the Future Energy Jobs Act ("FEJA"). FEJA introduced substantial reforms to the IPA's approach to support new renewable energy projects: namely, the State fully transitioned to a streamlined, centralized planning and procurement process, with both RPS targets and available budgets determined based on an electric utility's load for all retail customers and funding collected through a delivery services charge. New open-enrollment programs utilizing administratively established REC prices were introduced to support smaller-scale solar project development, and the IPA's approach to RPS compliance was to be outlined through a new long-term planning process specific to renewable energy programs and procurements occurring every two years. FEJA also introduced community solar—through which customers pay a project's owner/operator for a share of that photovoltaic ("PV") project's output—earning utility bill credits for the value of electricity generated by the facility, allowing customers that were unable to site a solar project on premises to nevertheless participate in the solar energy market.

Through a shift to collections across all retail customers, available funds used to support new renewable energy projects were stabilized and more substantial than under the prior RPS regime. What had been a $30 million to $100 million annual renewable resources budget grew to $220 million to $230 million per year. FEJA also shifted RPS compliance away from the procurement of "renewable energy resources"—which are either 1) a renewable energy credit associated with a megawatt-hour ("MWh") of generation, or 2) that REC plus the associated generation—to *only* compliance through the purchase and retirement of RECs.

FEJA also introduced a new regime through which utility-scale wind and solar projects were considered RPS compliant if physically located in Illinois, and projects in adjacent states may qualify only "if the generator demonstrates and the Agency determines that the operation of such facility or facilities will help promote the State's interest in the health, safety, and welfare of its residents" according to certain public interest criteria.[20] Projects located outside of Illinois or adjacent states are ineligible. This new approach constituted a narrowing of geographic allowances around from where RECs could be sourced for RPS compliance (as previously, Illinois law prioritized "Illinois and adjacent states" and then allowed for RECs from elsewhere) and has generally—albeit not exclusively—served to ensure that Illinois ratepayer funds are spent supporting new Illinois renewable energy projects.

While FEJA was very successful in jump-starting what had been a dormant solar marketplace in Illinois, the scale of funding proved insufficient to meet aggressive RPS goals. Furthermore, FEJA lacked a qualitative focus: success in renewable energy development was viewed as a function of new installed capacity, but without equity requirements, labor standards, considerations around whether community solar projects were community-driven, and other factors informing *how* the new clean energy economy was developing in Illinois (and not merely *whether* it was developing).

iii) Climate and Equitable Jobs Act ("CEJA") in 2021

Public Act 102-0662, also known as the Climate and Equitable Jobs Act or ("CEJA"), effective September 15, 2021, included more aggressive RPS goals and contained significant changes to the IPA's REC procurement obligations. These changes increased the State's RPS to reach a goal of 40% renewable energy by the 2030-2031 delivery year, and to reach 50% renewable energy by the 2040-2041 delivery year. Commensurate with more aggressive goals were changes in available budgets: annual renewable resources budgets are now $580-$590 million, up from the $220-$230 million authorized through FEJA.

CEJA also introduced a slew of new requirements aimed at ensuring that the Illinois renewable energy marketplace evolved in a manner consistent with the State's broader values. Among these were requirements that new wind project and, subject to limited exceptions, new solar project development, comply with Prevailing Wage Act requirements. New RPS-supported utility-scale solar and utility-scale wind projects must be "built by general contractors that must enter into a project labor agreement . . . prior to construction."[21]

CEJA also introduced a comprehensive new equity accountability system covering the IPA's renewable energy programs and procurements. One requirement is that "at least 10% of the project workforce for each entity participating in a procurement program . . . must be done by equity eligible persons or equity eligible contractors," increasing to a 30% "minimum equity standard" by 2030.[22] Within the Illinois Shines Program, the program dedicates at

[20] The IPA outlines its scoring process for determining whether these public interest criteria are met in Chapter 4 of its Long-Term Renewable Resources Procurement Plan. Since FEJA's passage five out-of-state projects have been successful in winning REC delivery contracts through IPA competitive procurements.

[21] 20 ILCS 3855/1-75(c)(1)(Q)(2).

[22] 20 ILCS 3855/1-75(c-10).

least 10% of program capacity—increasing to 40% by 2040—to projects submitted by equity eligible contractors (firms majority owned by equity eligible persons).

To support new utility-scale wind and solar project development (projects above 5 MW in size, selected through competitive procurement processes), CEJA introduced a new "Indexed REC" process based largely on a similar approach used in New York by the New York State Energy Research and Development Authority ("NYSERDA"). Given the limited long-term energy offtake market and the need for revenue certainty to support new project development, the Indexed REC pricing approach offers revenue certainty back to renewable energy project developers in a manner that functions similarly to a bundled fixed price REC + energy off-take agreement. Under this approach, a bidder bids in a strike price inclusive of both REC revenues and market energy prices, with the REC price floating based on wholesale energy market conditions. Thus, in times when energy revenues are presumed to be low, REC prices are high; in times when energy revenues are presumed to be high, REC prices adjust downward accordingly. The end result is revenue certainty regardless of wholesale energy market conditions, hopefully solving financing and development barriers.

CEJA also required the IPA to conduct a pair of procurements to support the development of new utility-scale photovoltaic projects coupled with storage "at or adjacent to the sites of electric generating facilities that burn or burned coal as their primary fuel source."[23] These "coal to solar" procurements, which were conducted in 2022, operated with statutorily established REC prices, maximum procurement quantities, project location requirements, and REC delivery timelines. CEJA also directed the Illinois Department of Commerce and Economic Opportunity ("DCEO") to support an additional 255 MW of storage at coal plant sites independent of the IPA's coal-to-solar procurements through $280 million in grants.

This support for new renewable energy projects (and limited support for storage projects) was adopted against the backdrop of CEJA's ambitious decarbonization targets. CEJA targets 100% clean energy by 2050 (inclusive of nuclear power, which cannot be used to meet the state RPS), with most state coal plants required to retire by 2030. Private coal and gas plants must cease operating by 2045 and reduce emissions by 45 percent by the year 2035. Given the challenges inherent in this ambitious transition, every five years (beginning in 2025), the IPA, Illinois Environmental Protection Agency ("IEPA"), and Illinois Commerce Commission ("ICC" or "Commission") must develop a report assessing "the current and projected status of electric resource adequacy and reliability throughout the State for the period beginning 5 years ahead, and proposed solutions for any findings."

CEJA also updated a FEJA-introduced rebate program for distributed generation system owners or operators.[24] The rebate program was updated to qualify distributed generation systems with nameplate generating capacity up to 5,000 kilowatts primarily used to offset the customer's electricity load; located on the customer's side of the billing meter and for the

[23] 20 ILCS 3855/1-75(c-5).

[24] 220 ILCS 5/16-107.6

customer's own use; and interconnected to electric distribution facilities owned by the electric utility by means of the inverter or smart inverter.[25] CEJA also provided compensation for retail customers[26] that install photovoltaic facilities paired with energy storage facilities on or adjacent to its premises for the benefits the facilities provide to the distribution grid.

While background, the above discussion is included not only to explain the evolution of Illinois renewable energy policy over time, but also because substantive elements of the proposals analyzed through this study borrow heavily from this regime. Further, each proposal is positioned at least in part as a solution to the challenges inherent in the State's current approach to supporting new renewable energy project development and aggressively pursuing decarbonization.

iv) 2023 Legislative Proposals

This study analyzes three policy proposals discussed during the Spring 2023 Legislative Session of the Illinois General Assembly (two of which were formally introduced as bills, and one of which has been discussed conceptually dating back to at least CEJA negotiations in 2021 and for which the IPA has obtained a draft bill):

- House Bill 2132 ("HB 2132") of the 103rd General Assembly as it passed out of the House on March 24, 2023 or a similar pilot program to establish one new utility-scale offshore wind project capable of producing at least 700,000 megawatt hours annually for at least 20 years in Lake Michigan that includes an equity and inclusion plan to create job opportunities for underrepresented populations and equity investment eligible communities, and includes a fully executed project labor agreement.
- Senate Bill 1587 ("SB 1587") and amendments to SB 1587 of the 103rd General Assembly filed prior to May 31, 2023 or a similar proposal for the deployment of energy storage systems supported by the State through the development of energy storage credit targets for the Agency to procure on behalf of Illinois electric utilities from privately owned, large scale energy storage providers using energy storage contracts of at least 15-year durations based on a competitive energy storage procurement plan developed by the Agency designed to enhance overall grid reliability, flexibility and efficiency, and to lower electricity prices.
- A policy establishing renewable energy credits for a high voltage direct current ("HVDC") transmission line that requires the Agency to procure contracts with at least 25 years but no more than 40 years duration for the delivery of renewable energy credits on behalf of electric utilities in Illinois with at least 300,000 customers from a HVDC transmission facility with more than 100 miles of underground

[25] "Smart inverter" means a device that converts direct current into alternating current and meets the IEEE 1547-2018 equipment standards. Until devices that meet the IEEE 1547-2018 standard are available, devices that meet the UL 1741 SA standard are acceptable.

[26] Retail customers of electric public utility with 3,000,000 or more retail customers.

transmission lines in Illinois capable of transmitting electricity at or above 525 kilovolts and delivering power in to the PJM market.

The features of each of these proposals are discussed more extensively in chapters 5-7 to provide further context for the analysis and modeling contained in this study. None of these proposals passed out of either the Illinois House or Senate in 2023. During the Spring 2023 Legislative Session, in an effort to have a "neutral party with relevant expertise evaluate each proposal to ensure it is consistent with the State's goals and maximizes benefits to Illinois residents," the Illinois Senate introduced a third amendment to House Bill 3445 ("HB 3445") directing the Agency to commission and publish a Policy Study evaluating the potential impacts of these proposals on Illinois' decarbonization goals, the environment, grid reliability, carbon and other pollutant emissions, resource adequacy, long-term and short-term electric rates, environmental justice communities, jobs, and the economy.

b) House Bill 3445 and Senate Bill 1699

i) Passage and Amendatory Veto

The third amendment of HB 3445 proposed a schedule for the Agency to publish a draft of the Policy Study, provide a 20-day open public comment period, and then the Agency would review public comments and publish a final Policy Study no later than March 1, 2024. However, HB 3445 was amended a fourth time, proposing the Transmission Efficiency and Cooperation Law as a new Article in the Public Utilities Act ("PUA"). This new Article would have given incumbent electric transmission owners the right of first refusal to construct, own, and maintain an electric transmission line that has been approved for construction in a transmission plan and will connect to facilities that are owned by that incumbent electric transmission owner and are or will be under the functional control of MISO.

Governor Pritzker issued an Amendatory Veto of HB 3445 on August 16, 2023, after finding that the right of first refusal language in the bill's fourth amendment would eliminate competition for transmission lines and could result in adverse ratepayer impacts.[27] After the Governor issued an Amendatory Veto, no positive action was taken on HB 3445, and the bill formally died on November 8, 2023.

However, on November 2, 2023, Senate Bill 1699 ("SB 1699") was amended to include the text from HB 3445 directing the IPA to commission and publish the Policy Study described above, as well as all the other components of HB 3445 related energy policy, except the provision related to right of first refusal. Governor Pritzker signed SB 1699 into law on December 8, 2023, creating Public Act 103-0580.

[27] https://www.illinois.gov/news/press-release.26893.html

c) IPA's Policy Study Timing and Decision-making

i) Announcements

The Agency began its Policy Study development over the summer of 2023, formally announcing on August 23, 2023, that it would conduct the Policy Study regardless of the final disposition of HB 3445.[28] Consistent with the schedule outlined in HB 3445, the Agency stated that it would publish an initial draft of the Policy Study by January 21, 2024 for public comment and publish a final Policy Study no later than March 1, 2024.[29]

ii) Feedback Requests

Pursuant to HB 3445 providing that the Agency may solicit information, including confidential or proprietary information, from entities likely to be impacted by the legislative proposals, the Agency requested technical data from proponents of HB 2132, SB 1587, and a policy for the Agency to procure RECs related to a HVDC transmission line. The Agency targeted outreach to companies, organizations, and advocates behind the policy proposals to receive data, inputs, and specifications for conducting the modeling and analytical work used in the Policy Study. On August 23, 2023, the Agency requested data such as potential locations for energy storage projects, latitude, and longitude of the wind turbine location for the offshore wind project in Lake Michigan, and the point of interconnection and injection amount (MW) of the HVDC transmission line.[30]

On September 29, 2023, the Agency announced its request for stakeholder feedback for broader information and additional perspectives on the policy areas being studied, including any data, information, reports, analyses, considerations, or other information which stakeholders believe should be brought to the IPA's attention for conducting a comprehensive and well-rounded analysis in the Policy Study.[31] The Agency requested that stakeholders submit their responses to the IPA by October 20, 2023 so that they Agency could review the responses and publish them on the Agency's website, barring any response designated as confidential by the stakeholder. The Agency received 10 sets of stakeholder comments varying in focus from offshore wind interconnection points; private development of an offshore wind project in Lake Michigan; migratory bird flight paths and avian mortality impacted by offshore wind in Lake Michigan; energy reliability, affordability, and decarbonatization provided by energy storage projects; community benefits and job creation

[28] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/procurement-plans/2024/ipa-to-conduct-policy-study-82323.pdf

[29] As January 21, 2024 was a Sunday, the Agency published the draft Policy Study on January 22, 2024 with a comment deadline of February 12, 2024. This approach lengthened the time for feedback to 21 days (as opposed to 20 days) but shortened the time for revision of the plan to 19 days. Consistent with Public Act 103-0580, the Agency published a final Policy Study on March 1, 2024 and delivered copies to the Governor and members of the Illinois General Assembly to include policy recommendations for the General Assembly.

[30] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/procurement-plans/2024/illinois-power-agency-policy-study-technical-information-82323.pdf

[31] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20230929-ipa-policy-study-general-information-request.pdf

from energy storage projects; and diversification of the State's energy portfolio for improved reliability and resiliency as Illinois transitions to a clean energy future.[32]

The IPA developed a Policy Study page[33] on the Agency's website to share key information and provide visibility into the Agency's Policy Study development including the posting of stakeholder comments. The Agency updates the page to serve as a source of information for stakeholders interested in the Policy Study.

iii) Draft Release, Issuance of Errata and Extended Comment Window

The Agency released a draft of the Policy Study on January 22, 2024 with a deadline of February 12 for written responses.[34] On February 7, the IPA determined that there were errors contained in the presentation of certain modeling results. In response, the Agency published an errata on February 8:

> *The Agency has identified an error in how some modeling results were reported in the draft Policy Study that understated the potential benefits associated with the energy storage policy option. Errors were also found in the presentation of costs for SOO Green and in the combined case model that looked at adopting all three of the policies studied.*
>
> *The primary error occurred when the energy revenue outputs for the energy storage modeling and the offshore wind component of the combined results were transferred into summary spreadsheets for use in the preparation of the draft Policy Study. More specifically, certain data outputs of Aurora (the production cost simulation model used for the Policy Study to model impacts on wholesale electricity prices, emissions, and changes to the composition and operation of the generation resource mix in Illinois) are reported in thousands of dollars, 1 and those were not consistently updated during the transfer to the summary spreadsheets. Additional errors include: (1) the use of an incorrect financing carrying cost that did not reflect the benefits of the Investment Tax Credit, affecting the cost calculations for distributed energy storage; (2) the use of inflation adjusted costs rather than nominal costs in certain tables, affecting the cost calculations for SOO Green; and (3) the cost calculation erroneously double-counted certain project revenues for SOO Green, affecting the combined case results. The errors did not impact the reporting of results of the modeling for offshore wind as a stand-alone case.*

The errata then detailed the errors and provided updated values.[35] The Agency also announced in the errata that it would release detailed work papers for all the models in response to a request from representatives of the energy storage industry.

[32] https://ipa.illinois.gov/ipa-policy-study/stakeholder-feedback-on-ipa-policy-study.html

[33] https://ipa.illinois.gov/ipa-policy-study.html

[34] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/procurement-plans/2024/ipa-to-conduct-policy-study-82323.pdf

[35] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/policy-study-errata-announcement-8-feb-2023.pdf

On February 13, 2024, after receiving feedback that commenters needed more time to respond to the Draft in light of the errata, the Agency extended the window for comments to February 26, 2024.[36]

On February 16, 2024, the IPA published the workpapers promised in the errata on the Agency's website. The Agency also announced updates to the workpapers based on comments received from stakeholders.[37]

iv) Draft and Errata Feedback

The Agency received 27 written comments from stakeholders: Ameren Illinois, Bird Conservation Network, Chicagoland Chamber, Climate Jobs Illinois, ComEd, County Assessment Officers Association, Diamond Offshore Wind, Energy Storage Associations, Environmental Law and Policy Center, Faith in Place, Hire360, Illinois Clean Jobs Coalition, Illinois International Port District, Invenergy Transmission, Iron Workers District Council of Chicago & Vicinity, J Power USA, Magellan Wind, NRG Midwest Storage, Oceantic Network, Office of the Illinois Attorney General, Paul G. Neilan, SOO Green (initial and errata comments), Strategic Economic Research (initial and errata comments), Union of Concerned Scientists/Environmental Defense Fund/Sierra Club, Vistra Corp (initial and errata comments).[38]

Commenters covered a range of policy impacts related to the three study areas. Some comments simply expressed support or disapproval of the 'proposals studied, while others offered specific critiques and questions about assumptions and modeling choices made in the draft. The Agency carefully reviewed all and has endeavored to address the feedback in the final version of this Policy Study.

[36] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/policy-study-additional-time-announcement.pdf,

[37] https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/policy-study-workpaper-release-announcement-16-feb-2024.pdf.

[38] https://ipa.illinois.gov/ipa-policy-study/stakeholder-feedback-on-draft-policy-study.html

3) Legislative Proposals Used in the Policy Study

This Legislative Proposals chapter discusses the substance of three policy proposals discussed during the Spring 2023 Legislative Session of the Illinois General Assembly. The policy proposals include (a.) Senate Bill 1587 and amendments to Senate Bill 1587 for the deployment of energy storage systems supported by the State through the development of energy storage credit targets for the Agency to procure on behalf of Illinois electric utilities; (b.) House Bill 2132 or a similar pilot program to establish one new utility-scale offshore wind project capable of producing at least 700,000 megawatt hours annually for at least 20 years in Lake Michigan; and (c.) a policy establishing high voltage direct current renewable energy credits that requires the Agency to procure contracts for the delivery of renewable energy credits on behalf of electric utilities in Illinois from a high voltage direct current transmission facility. The content of each policy proposal is discussed below, including the substance of each proposal, the Agency's procurement targets, procurement processes, and contract requirements under each proposal, and how each proposal is financed.

a) Senate Bill 1587: Procurement of Energy Storage Credits

i) Substance of Senate Bill 1587

(1) Developing Energy Storage Policy in Illinois

(a) Legislative History of Senate Bill 1587

While CEJA did provide incentives for the development of storage projects at coal-fired power plants through discrete initiatives, CEJA did not enact comprehensive energy storage policy for Illinois. Instead, CEJA required the Commission (in consultation with the IPA) to develop a report and initiate a proceeding examining programs, mechanisms, and policies that could support the deployment of energy storage systems.

In May 2022, the Commission published an Energy Storage Program Report which provided recommendations for various energy storage programs.[39] Commission Staff recommended energy programs that provide compensation for energy storage systems that are built and operated in conjunction with existing or new utility-scale, distributed generation, and/or community solar renewable energy facilities funded through the Illinois RPS.[40] Staff recommended programs where Ameren Illinois and ComEd, working in conjunction with their respective RTOs (MISO and PJM), identify locations where the deployment of storage would prevent otherwise necessary short-term transmission system investments and could meet ancillary service needs and provide for cleaner and/or more cost-effective operation of the electric grid. Additionally, Staff recommended a program that works to support community

[39] https://www.icc.illinois.gov/informal-processes/energy-storage-program. The Report is also discussed further in Section 5)b)i)(1).

[40] https://www.icc.illinois.gov/downloads/public/informal-processes/energy-storage-program/energy-storage-program-report-may-25-2022.pdf at 47-48.

resiliency efforts focused on identifying and serving customers' needs and addressing energy vulnerabilities. Further, Staff recommended a program in which the electric utilities, working with PJM and MISO, identify points on their transmission grids in Illinois at which installation of utility-scale energy storage systems would be necessary or beneficial to support grid reliability, stability, and operability; and finally, Staff recommended a Market Accelerator Incentive Program to jump-start energy storage deployment in Illinois with a one-time incentive payment.

SB 1587, proposing a planning and procurement process to procure "energy storage credits" to facilitate the development of new energy storage projects, was introduced in the Illinois General Assembly in February 2023, and a Senate Energy and Public Utilities Committee Subject Matter Hearing was in March 2023 on SB 1587.[41] Industry stakeholders and the IPA's Acting Director provided testimony on topics including the Agency's procurement processes, utilities filing tariffs to support energy storage procurements, energy storage duration and energy storage system capacity values, and a feasible timeline to develop a formal energy storage procurement program. SB 1587 was amended in May 2023 to include various proposals to compensate behind-the-meter energy storage as discussed below.

(b) IPA's Energy Storage Procurement Requirements

SB 1587 directs the Agency to develop a long-term energy storage resources procurement plan that will result in Illinois electric utilities contracting for energy storage credits[42] from contracted energy storage systems[43] in specified amounts for at least 15 years.[44] "Energy storage credits" procured by the IPA to facilitate the development of energy storage systems are expected to operate similar to RECs used to facilitate the development of new renewable energy projects, with Illinois electric utilities serving as Buyers under energy storage credit contracts leveraging ratepayer collections to provide revenue back to new energy storage system owners and operators.

SB 1587's proposed planning process requires that the Agency publish an initial energy storage resources procurement plan no later than 180 days after the bill is enacted into law. Subsequently, the Agency would review, and may revise the plan at least every two years thereafter to ensure the plan is sufficient to support the State's renewable energy standards and carbon emission standards. The Agency's initial energy storage resources procurement plan and all subsequent revisions would be subject to review and approval by the

[41] https://ilga.gov/legislation/billstatus.asp?DocNum=1587&GAID=17&GA=103&DocTypeID=SB&LegID=146343&SessionID=112

[42] SB 1587 defines "energy storage credit" as a fungible credit that represents the flexibility value of a contracted energy storage system. An energy storage credit is produced for each one megawatt of energy storage capacity multiplied by the energy storage duration each day that the contracted energy storage system is interconnected with wholesale electricity markets. Also as defined by SB 1587, "Energy storage credit value" means a price, measured in dollars per credit, calculated for each day for a contracted energy storage system by subtracting the daily energy volatility index and the reference capacity price from the energy storage strike price.

[43] SB 1587 defines "contracted energy storage system" as an energy storage system that is the subject of a long-term energy storage contract under Section 1-93. "Contracted energy storage system" does not include an energy storage system put into service before the effective date of this amendatory Act of the 103rd General Assembly. 20 ILCS 3855/1-10.

[44] SB 1587 defines "long-term energy storage contract" as a contract for the purchase of energy storage credits generated by an energy storage system for a period of at least 15 years.

Commission, although SB 1587 does not include a timeline for ICC approval of that plan.[45] Similar to the ICC's role across renewable energy credit procurements, the Commission would also approve the process for the submission, review, and approval of the proposed contracts to procure energy storage credits or implement the programs authorized by the Commission pursuant to the long-term energy storage resources procurement plan.

(c) Compensation Structure

For meeting ambitious energy storage procurement targets, SB 1587 proposes utilizing a compensation structure for new energy storage systems similar to the Indexed renewable energy credit ("REC") procurement process for procuring RECs from utility-scale renewable energy projects. This process involves respondents (bidders) offering an energy storage "strike price"[46] with bids selected based on the lowest strike price of bids with equal energy storage duration.[47] As with Indexed REC procurements, that strike price includes both actual credit revenues and assumed wholesale energy market revenues.

Loosely, this process would work as follows: the purchase price of the indexed energy storage credit payment would be calculated for each day with the energy storage credit equal to the difference resulting from subtracting from the energy storage strike price the sum of the daily energy volatility index[48] and the reference capacity price for that day. If this difference results in a positive number, the electric utility owes the seller this amount multiplied by the number of indexed energy storage credits produced on that day. If this difference results in a negative number, the settlement will be zero. The parties would then cash settle every month, summing up all settlements for the prior month.

Much like the Indexed REC procurement process for utility-scale wind and solar process, this structure ensures revenue certainty to a storage project owner or operator at that strike price. During times when wholesale markets provide lower revenues back, the energy storage credit price is higher, making the seller whole at the strike price. During times when wholesale markets provide higher revenues back, the energy storage credit price drops

[45] Copies of the initial energy storage resources procurement plan and all subsequent revisions shall be posted and made publicly available on the Agency's and Commission's websites, and copies shall also be provided to each affected electric utility. An affected utility and other interested parties shall have 45 days following the date of posting to provide comment to the Agency on the initial energy storage resources procurement plan and all subsequent revisions. All comments shall be posted on the Agency's and Commission's websites. Websites and the plan will consider additional procurement approaches that would result in the electric utilities contracting for energy storage to achieve energy storage capacity targets in 1-93(a).

[46] SB 1587 defines "Energy storage strike price" as a contract price for energy storage credits from a contracted energy storage system.

[47] In the Agency's long-term renewable resources procurement plan, the IPA must identify the RTO or ISO to which energy storage systems will be interconnected to be eligible to offer a strike price for energy storage credits. For all solicitations prior to the delivery year 2028, the Agency must strive to procure at least 70% of energy storage credits from energy storage systems interconnected to MISO, and at least 10% of energy storage credits from energy storage systems located within a city with population of more than 1,000,000 people and interconnected to PJM Interconnection, LLC. For solicitations in the delivery year 2028 and thereafter, the Agency must designate the RTO or ISO to which energy storage systems would be interconnected to be eligible to offer a strike price for energy storage credits.

[48] SB 1587 defines "daily energy volatility index" as a calculation, for a contracted energy storage system, of the difference between the "X" highest-priced hours and the "X" lowest-priced hours of the energy storage duration of the contracted energy storage system for each day in the day-ahead energy market of the applicable pricing node of the independent system operator or regional transmission organization, where "X" equals the energy storage duration of the contracted energy storage system.

accordingly – but unlike the Indexed REC procurement process or the carbon mitigation credit contracts used to support the ongoing operation of nuclear plants, that price cannot turn negative such that the Seller makes a payment back to Buyer.

SB 1587 proposes that the IPA use its Procurement Administrator, in consultation with Commission Staff and the Procurement Monitor, to develop confidential price benchmarks (i.e., maximum acceptable strike prices) based on publicly available data on regional technology costs; benchmarks are also subject to ICC review and approval.

(d) Procurement Targets and Storage Duration

SB 1587 proposes through the creation of a new Section 1-93 of the IPA Act, that the Agency's storage procurement plan would include procurement target quantities of at least the following:

- 1,000 megawatts of cumulative energy storage capacity by delivery year 2024;
- 3,000 megawatts of cumulative energy storage capacity by delivery year 2026;
- 5,000 megawatts of cumulative energy storage capacity by delivery year 2028;
- 7,500 megawatts of cumulative energy storage capacity by delivery year 2030.

While SB 1587 does not create requirements around the underlying technology for new storage projects used to meet these requirements, all solicitations conducted prior to the delivery year 2028 would be for energy storage with 4-hour duration. For solicitations in the delivery year 2028 and thereafter, the Agency would designate the energy storage duration(s) and the amount of energy storage capacity at each duration from which the Agency intends to procure energy storage credits. Similarly, SB 1587 does not require that storage energy be initially generated from renewable energy projects.

SB 1587 also proposes a study to determine whether these ambitious procurement targets are sufficient. By December 31, 2026, and every two years thereafter, the Agency would conduct an analysis to determine whether the contracted quantity of energy storage in energy storage capacity and energy storage duration is sufficient to support the State's renewable energy standards and carbon emission standards. If the Agency determines that the need for energy storage capacity or energy storage duration is greater than these energy storage credit targets, these targets can be adjusted upward: the Agency would then establish for Commission approval new energy storage credit targets to meet the identified need. However, this study would not appear to allow for a downward adjustment in goals.

Similarly, while SB 1587's energy storage credit procurement goals do not continue beyond 2030, if the Agency determines that deployment of energy storage beyond 2030 would not be achieved through wholesale market prices and other energy storage programs established by the State, the Agency would then establish additional targets for years beyond 2030.

(e) Tariffs Assessed on all Retail Customers per kWh Charge

Under SB 1587, purchases of energy storage credits are made by Illinois electric utilities, with that revenue back to the projects (through the Sellers of energy storage credits) used to support those systems' successful development and operation. To effectuate this, SB 1587 proposes amendments to Section 16-108 of the PUA[49] to provide for electric utilities' cost recovery for procuring the energy storage credits, reasonable costs that the utility incurs as part of the procurement processes and implementing and complying with plans and processes approved by the Commission through a uniform cents per kilowatt-hour charge as a separate line item on each customer's bill.

This compensation, collections, and payment structure is similar to that used for the State's RPS, through which collections are made under authority from Section 16-108 of the PUA. However, unlike the RPS, SB 1587 does not provide an annual procurement budget for energy storage credits (whether through a rate impact cap or a fixed percentage applied to electric utilities' retail customers' bills).

(f) Minimum Equity Standard Requirements

CEJA created an equity accountability system[50] mandating, among other things, minimum equity standards ("MES")[51] for the project workforce of entities applying for REC contracts under the IPA's Indexed REC procurements, Illinois Shines Program, and Self-direct Program. SB 1587 proposes that bidders in energy storage credit procurement processes likewise comply with equity accountability system requirements in subsection (c-10) of Section 1-75 of the IPA Act.

Some elements of adapting existing equity accountability system requirements to energy storage are more straightforward than others. For example, the MES—through which a certain percentage of the project workforce must be composed of equity eligible persons or equity eligible contractors—would seem straightforward to apply, as new energy storage projects feature a "project workforce" similar to new renewable energy projects. But the equity accountability system is also inclusive of the equity eligible contractor category for the Illinois Shines Program and equity eligible contractor uses bid selection preferences for the IPA's Indexed REC procurements, and it is unclear whether some carveout or set-aside is intended to apply for equity eligible contractors as applicants to energy storage credit procurements.

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[49] 220 ILCS 5/16-108.

[50] The purpose of the equity accountability system is to establish data collection and reporting requirements and improve transparency regarding who participates in and benefits from the Illinois clean energy economy.

[51] Public Act 102-0662 established a "minimum equity standard" in Section 1-75(c-10) of the IPA Act (20 ILCS 3855/1-75(c-10)) applicable to the project workforce for firms participating in certain IPA renewable energy programs and procurements, requiring that at least 10% of the project workforce for each entity participating in a procurement or applicable program must be done by equity eligible persons or equity eligible contractors. The Agency must increase the minimum percentage each delivery year thereafter by increments that ensure a statewide average of 30% of the project workforce for each entity participating in a procurement or applicable program is done by equity eligible persons or equity eligible contractors by 2030.

(g) Labor Requirements

Energy storage credits would be procured from energy storage systems built by general contractors that enter into a project labor agreement prior to construction. The project labor agreement would be filed with the Agency's Director in accordance with procedures established by the Agency through its storage procurement plan. SB 1587 also proposes that winning bidders in the IPA's energy storage credit procurements must comply with the prevailing wage requirements in Section 1-75(c)(1)(Q) of the IPA Act.[52]

(h) Locational Considerations

Energy storage procurements would also have to comply with the geographic requirements in Section 1-75(c)(1)(I) of the IPA Act, which would allow the Agency to procure energy credits from facilities located in Illinois and states adjacent to Illinois if the energy generator demonstrates and the Agency determines that the operation of such facility or facilities will help promote the State's interest in the health, safety, and welfare of its residents. While the Agency has assumed that all supported projects will be developed in Illinois in modeling the impacts of SB 1587, it is important to note that SB 1587 could allow for some level of adjacent state project participation. More information on how the Agency determines whether an adjacent state project meets this public interest criteria can be found in Chapter 4 of the IPA's Long-Term Renewable Resources Procurement Plans.[53]

(i) Long-Duration and Multi-Duration Storage Proposal Description

SB 1587 also proposes to add Section 1-94 to the IPA Act which would authorize the Agency to develop and implement a firm energy resource procurement plan[54] for conducting competitive solicitations to deploy new long-duration[55] and multi-day[56] energy storage. SB 1587 specifies that the Agency's firm energy resource procurement plan must ensure that a minimum of two new long-duration or multi-day energy storage resources, each with a rated capacity greater than 20 megawatts, would be deployed or contracted by the end of delivery

[52] Prevailing wage is a minimum compensation level by county set by the Illinois Department of Labor for construction activities related to public works.

[53] The current Long-Term Renewable Resources Procurement Plan is the 2022 Plan available at: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/modified-2022-long-term-plan-upon-reopening-9-may-2022-final.pdf.

[54] SB 1587 defines "firm energy resource" as electrical resources, including long-duration energy storage and multi-day energy storage, that can individually, or in combination, deliver electricity with guaranteed high availability at rated capacity for the expected duration of multi-day extreme or atypical weather events, including periods of low renewable energy generation, and facilitate integration of eligible renewable energy resources into the electrical grid and the transition to a zero-carbon electrical grid. The General Assembly gave the Agency 365 days from the effective date of the Bill to develop ~~a~~ firm energy resource procurement plan in accordance with this Section of SB 1587 and Section 16-111.5 of the Public Utilities Act.

[55] SB 1587 defines "long-duration energy storage" as an energy storage system capable of dispatching energy at its full rated capacity for 10 hours or greater.

[56] SB 1587 defines "multi-day energy storage" as an energy storage system capable of dispatching energy at its full rated capacity for greater than 24 hours.

year 2026; however, the process and timeline for ICC consideration of this separate plan is not presently included within SB 1587.

Regarding energy storage duration in the firm energy resource procurement, as discussed in Chapter 5 on Energy Storage, while the current market trend is 4-hour duration storage, as more energy storage systems are deployed to serve peak demand and ensure reliability, longer-duration storage will likely replace the 4-hour span, which will be needed to meet SB 1587's proposed long-duration (for 10 hours or more) and multi-day energy storage requirements.

(j) Various Behind the Meter and Community Solar Storage Proposal Descriptions

(i) Virtual Power Plant Program

In addition to changes to the IPA Act used to facilitate the development of thousands of megawatts of new medium-duration energy storage projects potentially operating disassociated with any specific generating facility, Senate Amendment 1 to SB 1587 introduced a variety of proposals to support the development of new energy storage projects operating coupled with distributed generation or community solar projects. As none of these policies feature system deployment targets or proposed values of compensation back to storage project owners or operators, undertaking modeling these policies' potential impacts proved particularly challenging.

SB 1587 proposes a virtual power plant program whereby behind-the-meter systems may receive dispatch signals and aggregate electricity generation to help manage aggregated load. Accordingly, if enacted, SB 1587 would add Section 16-107.8 to the PUA to establish a virtual power plant program through which third-party aggregators[57] receive dispatch signals from utilities or utility-contracted DERMS[58] providers and help reduce the net impact or create a net positive impact on the grid by deploying the electric utility's storage resources at times of stress and energy scarcity on the utility's system. The program would enable eligible retail customers of electric utilities with eligible devices[59] to help reduce utilities' annual load forecasts and benefit all eligible retail customers—apparently meaning that a customer would need to take default supply from Ameren or ComEd to be eligible for participation.

To effectuate this program, each electric utility serving more than 300,000 customers as of January 1, 2023 (e.g., Ameren and ComEd) would be required to propose an initial tariff

[57] "Aggregator" means a party, other than the electric utility or its affiliate, that (i) represents and aggregates the load of participating customers who collectively have the ability to deploy 100 kilowatts or more of eligible devices and (ii) is responsible for performance of the aggregation in the program.

[58] "Distributed energy resources management system" or "DERMS" means a platform that may be used by distribution system operators or utilities to integrate grid resources, such as distributed energy resources, into system operations.

[59] "Eligible device" means a distributed renewable energy device or devices paired with one or more energy storage systems interconnected behind the meter of a participating customer.

within 60 days. The tariff must include that each request by the utility to deploy eligible systems would be considered an event; in exchange for an aggregator facilitating the dispatch of eligible systems during hours identified by the utility under the tariff, the utility would, after one year of demonstrated performance by the aggregator, compensate the aggregator annually in an amount per kilowatt multiplied by the average number of kilowatts discharged during events in a calendar year by those eligible systems enrolled with the aggregator, with the amount per kilowatt to be determined by the Commission.[60] The utilities' tariff would also be required to identify the number of hour-long events, months during which events may occur, and time ranges during which an event may occur. The bill proposes that a utility may not call less than 30 events or more than 60 events during a June 1 through May 31 delivery year, one or more events on a single calendar day may not total more than 2 hours; and an event may not be called on less than 24 hours of notice.

The Commission would then approve, or approve with modifications, the tariff filed by each utility within 180 days of the filing. After two delivery years of the tariffs, the Commission would issue a report to the General Assembly assessing the value and efficacy of the virtual power plant program, including proposals for expansions or modifications. While the Commission would determine the amount per kilowatt that each aggregator would be compensated as to encourage aggregator participation for at least five years, the tariffs would not reflect any additional charges, fees, or insurance requirements imposed on those owning or operating distributed renewable energy generation devices, distributed energy resources, or energy storage systems beyond those imposed on similarly situated customers that do not own or operate these resources. Costs associated with this program would be considered power procurement costs by electric utilities, and thus be socialized across eligible retail customers (Ameren and ComEd customers who take default supply from their incumbent electric utility).

(ii) Large Distributed Energy Resources Dynamic Load Program

SB 1587 also proposes a large, distributed generation program that would enable participating customers who have the collective ability to deploy 100 kilowatts or more of eligible devices. SB 1587 would add Section 16-107.9 to the PUA to establish a large distributed energy resources dynamic load program to encourage and compensate aggregators with eligible devices[61] that have smart inverters[62] installed to deploy at times of stress on the grid and in wholesale energy markets to benefit all of the utility's customers with enhanced reliability and protection from wholesale price increases.

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[60] The Commission would determine the value of the performance payment by considering the benefits to the utility and ratepayers of peak remediation, reduced capacity and transmission allocations to the applicable regional transmission organization zone, and a reasonable estimation of the value of reduced transmission and distribution investment and other grid services. The value must be set to encourage robust participation and shall be for a term of no less than five years.

[61] "Eligible devices" means a distributed renewable energy device or community renewable generation projects paired with one or more energy storage systems.

[62] "Smart inverter" has the meaning set forth in subsection Section 16-107.6(a) of the PUA.

Each electric utility serving more than 300,000 customers as of January 1, 2023 would be required to propose an initial tariff within 60 days of the effective date of the Act. The tariff would include that each request by the utility for an aggregator or participating customer to deploy eligible devices to the level identified in advance by the aggregator or participating customer would be an event. In exchange for an aggregator dispatching eligible systems during hours identified by the utility, the utility would, after one year of demonstrated performance by the aggregator, compensate the aggregator annually in an amount per kilowatt multiplied by the average number of kilowatts discharged during events in a calendar year by those eligible systems enrolled with the aggregator, with the amount per kilowatt to be determined by the Commission.[63] Further, SB 1587 proposes that an aggregator or participating customer applying individually must represent that it has identified one or more eligible devices with an aggregate export capacity of at least 100 kilowatts for participation, and each participating customer would be required to have smart inverters installed on their eligible devices. The bill also provides that a participating customer may enroll in the large distributed energy resources dynamic load program for up to five years. The electric utility would not be able to require collateral from a participating customer or an aggregator. The electric utility would not be able to call an event with less than 24 hours' prior notice nor may one or more events on a single calendar day total more than two hours.

Utilities would recover the costs of the program through delivery rates—thus socializing the program cost across all retail customers, as the program generally supports larger customers who may not be eligible for default supply and generally choose supply service from a competitive supplier—and the Commission would approve or approve with modifications the tariff filed by each utility within 240 days of its filing. After two delivery years of the tariffs, the Commission would issue a report to the General Assembly assessing the value and efficacy of the aggregated distributed energy resource program, including proposals for expansions or modifications. The Commission may consider providing compensation to aggregators to the extent that the aggregators' participating customers are located in equity investment eligible communities.[64] The tariffs approved by the Commission would not reflect any additional charges, fees, or insurance requirements imposed on those owning or operating distributed renewable energy generation devices, distributed energy resources, or energy storage systems beyond those imposed on similarly situated customers that do not own or operate these resources.

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[63] In determining the value of the performance payment, the Commission must consider the benefits to the utility and ratepayers of peak remediation, reduced capacity and transmission allocations to the applicable regional transmission organization zone, and a reasonable estimation of the value of reduced transmission and distribution investment and other grid services. The value must be set to encourage robust participation and shall be for a term of no less than five years.

[64] 20 ILCS 3855/1-10. Equity investment Eligible Communities are defined as 1) R3 Areas as established pursuant to the Cannabis Regulation and Tax Act, and 2) Environmental Justice Communities where residents have historically been subject to disproportionate burdens of pollution, including pollution from the energy sector. For maps and address lookup tools for these two areas see: https://r3.illinois.gov/eligibility and https://www.illinoissfa.com/environmental-justicecommunities/ respectively; the Agency has also developed an Equity Eligible Investment Community map here: https://energyequity.illinois.gov/resources/equity-investment-eligible-community-map.html. Changes to the Environmental Justice Communities and R3 Area maps are subject to the various update process of each respective group.

(iii) Peak Remediation Program

Lastly, SB 1587 proposes to compensate community renewable generation projects[65] with a nameplate capacity of 100-5,000 kilowatts paired with one or more energy storage systems to discharge electricity into the grid during peak demand hours of 4-8 p.m. during the months of June, July, August, and September. The goals of the program are to alleviate stress on the grid during peak electricity demand when not enough renewable resources are available to meet high demand, and to reduce peak demand costs allocated to ratepayers.

To do so, SB 1587 proposes to add Section 16-107.10 to the PUA whereby each electric utility serving more than 300,000 customers as of January 1, 2023, would propose an initial tariff within 90 days of the effective date of the Act. The initial tariff would compensate eligible devices with a nameplate capacity between 100-5,000 kilowatts for discharging into the grid during defined discharge hours. In exchange, the utility would compensate the owner, operator, or a third party designated by the owner or operator of the eligible device, a peak discharge payment in an amount to be determined by the Commission.[66] The electric utility would not be able to require collateral from the eligible device owner or operator, and the utility may not control deployment of the storage device.

Under this peak remediation plan, the utility would recover the costs incurred under the tariff through delivery rates, including delivery rates authorized by its multi-year rate plan. The Commission would be required to approve or approve with modifications the tariff filed by each utility within 240 days of the filing. After the threshold date,[67] the utility would then file an annual petition to update the initial tariff for eligible systems that begin to take service under the tariff during the annual period, and the Commission would approve the petition to update the initial tariff within 90 days after the petition is filed. However, the tariffs approved by the Commission must not reflect any additional charges, fees, or insurance requirements imposed on those owning or operating distributed renewable energy generation device, distributed energy resources, or energy storage system beyond those imposed on similarly situated customers that do not own or operate these resources.

[65] "Community renewable generation project" means an electric generating facility that: (1) is powered by wind, solar thermal energy, photovoltaic cells or panels, biodiesel, crops and untreated and unadulterated organic waste biomass, and hydropower that does not involve new construction of dams; (2) is interconnected at the distribution system level of an electric utility, a municipal utility that owns or operates electric distribution facilities, a public utility as defined in Section 3-105 of the Public Utilities Act, or an electric cooperative, as defined in Section 3-119 of the Public Utilities Act; 3) credits the value of electricity generated by the facility to the subscribers of the facility; and (4) is limited in nameplate capacity to less than or equal to 5,000 kilowatts.

[66] The peak discharge payment must be based on the benefits to the utility and ratepayers of peak remediation, reduced capacity, and transmission allocations to the applicable regional transmission organization zone, and a reasonable estimation of the value of reduced transmission and distribution investment and other grid services. The value should encourage robust participation and must be for a term of no less than 15 years.

[67] "Threshold date" means December 31, 2024 or the date on which the utility's tariff or tariffs setting the new compensation values established under subsection (e) take effect, whichever is later.

b) House Bill 2132: Procuring RECs from Offshore Wind

i) Substance of House Bill 2132

(1) How Offshore Wind RECs Are Allocated in Illinois RPS

HB 2132 proposes updates to Section 1-75(c)(1)(G) of the IPA Act to require that, within 360 days after the bill's enactment, the IPA would conduct at least one utility-scale offshore wind REC procurement event to procure at least 700,000 RECs, delivered annually for 20 years, from one new utility-scale offshore wind project[68] in Lake Michigan. Unlike with SB 1587, the IPA would not develop a procurement plan to guide this procurement event; instead, similar to how the IPA conducted competitive procurements through only statutory guidance shortly after the passage of both FEJA and CEJA, the IPA would conduct this procurement event relying only on guidance from Illinois law.

(2) Rate Impact Caps and Line-Item Tariff Collection

Payment for RECs under the Agency's REC programs and procurements are capped by an annual renewable resources budget.[69] Specifically, Section 1-75(c)(1)(E) of the IPA Act provides that "the total of renewable energy resources procured under the procurement plan for any single year . . . shall be reduced for all retail customers based on the amount necessary to limit the annual estimated average net increase due to the costs of these resources included in the amounts paid by eligible retail customers in connection with electric service to no more than 4.25% of the amount paid per kilowatt-hour by those customers during the year ending May 31, 2009."[70] This results in an annual renewable resources budget across all applicable utilities of $580 to $590 million dollars; actual amounts vary based on annual retail electricity sales, as outlined in Chapter 3 of the IPA's Long-Term Renewable Resources Procurement Plan.

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[68] As defined by HB 2132, "New utility-scale offshore wind project" means an electric generating facility that: (1) generates electricity using wind; (2) has a nameplate capacity that is greater than 150 megawatts; (3) is sited in the waters of Lake Michigan; (4) is interconnected to the PJM Interconnection's regional transmission system; (5) has a fully executed project labor agreement with the applicable local building and construction trades council; (6) has a comprehensive and detailed equity and inclusion plan crafted to create opportunities for underrepresented populations in addition to equity investment eligible communities; and (7) has a permit pursuant to the Rivers, Lakes, and Streams Act from the Department of Natural Resources for a site that is in a preferred area pursuant to Section 15 of the Lake Michigan Wind Energy Act.

[69] 20 ILCS 3855/1-75(c)(1)(E). "The required procurement of cost-effective renewable energy resources for a particular year commencing prior to June 1, 2017 shall be measured as a percentage of the actual amount of electricity (megawatt-hours) supplied by the electric utility to eligible retail customers in the delivery year ending immediately prior to the procurement, and, for delivery years commencing on and after June 1, 2017, the required procurement of cost-effective renewable energy resources for a particular year shall be measured as a percentage of the actual amount of electricity (megawatt-hours) delivered by the electric utility in the delivery year ending immediately prior to the procurement, to all retail customers in its service territory."

[70] 20 ILCS 3855/1-75(c)(1)(E). The amount paid per kilowatt-hour means the total amount paid for electric service expressed on a per kilowatt-hour basis. The total amount paid for electric service includes without limitation amounts paid for supply, transmission, capacity, distribution, surcharges, and add-on taxes.

(a) Rate Impact Cap Changes and Interaction with Existing Rate Impact Cap

HB 2132's proposes a 0.25% rate impact cap increase (increasing the cap to 4.5%) on to support new utility-scale offshore wind projects, although that increase would not take effect upon bill passage; the project developer would instead provide notice that the project is nearing energization, which would trigger heightened collections.[71] The increase in the rate impact cap from 4.25% to 4.5% would constitute approximately $33-34 million a year in new collections from ratepayers and thus that incremental increase is what the Agency understands would be dedicated to supporting this project. That additional funding is then used to procure RECs from a new utility-scale offshore wind project to provide revenue back to that project's owner or operator. Approximately $34 million of annual collections would be used to procure 700,000 RECs annually and would result in a price of $48.57 per REC.

However, as described below, HB 2132 also requires utilization of an Indexed REC structure for determining *actual* REC prices (and thus actual budget impacts). As REC prices would float under HB 2132 based on wholesale market conditions, interpretive decisions would be required to determine how this budget allocation would apply to payments under REC delivery contracts – perhaps the contract would simply be capped at approximately $680 million over 20 years, drawn down as required through each settlement period.

(3) Procuring RECs from One New Utility-Scale Offshore Wind Project in Lake Michigan

(a) Electricity and Capacity Sold to Other Parties

Similar to how existing Illinois RPS initiatives support new project development not through the procurement of energy or capacity but instead through the procurement of renewable energy credits, HB 2132 supports the development of a new offshore wind project through the sale of RECs from that project to utility counterparties as Buyers. Each REC represents the environmental value of a megawatt hour of renewable energy generated from the renewable energy system. While RECs are created when renewable energy systems generate electricity, RECs are separate from the electricity produced by the renewable energy system which often goes into the local power grid and is indistinguishable from energy sourced from non-renewable energy systems. Under HB 2132, the project's owner or operator would not be transferring energy or capacity to Illinois electric utilities; only RECs would be transferred, although the Indexed REC structure strongly incents energy sales into wholesale markets in a manner ensuring that project operators are fully compensated at that bidder's strike price.

[71] Specifically, HB 2132 proposes that "no more than 4.5% of that amount [the amount paid per kilowatt-hour by all retail customers] as of the billing month following the expected date that a new utility-scale offshore wind project commences commercial operations and is expected to begin delivering power to the PJM Interconnection, LLC transmission grid. The new off-shore utility-scale wind project must provide notice of the expected commercial operation date to the Illinois Power Agency and each electric utility at least 90 days prior to commencing commercial operation and delivering power to the PJM Interconnection, LLC transmission grid."

In Illinois, RECs procured through IPA-administered programs and procurements are purchased and retired by electric utilities to comply with Illinois' RPS, which sets goals for utilities to obtain a percentage of their electricity from renewable energy resources. Once a REC used for the Illinois RPS is sold to a utility, it is "retired" to prevent another party from using it again and the utility can claim credit for that REC for their RPS obligations.[72] Under HB 2132, RECs are retired to further compliance with the State's existing RPS goals.

(b) Offshore Wind Project Decommissioning Requirement

HB 2132 also proposes that any REC contract awarded to a new utility-scale offshore wind project must also contain a project decommissioning requirement. However, the bill does not provide guidance on what the decommissioning requirement must entail, such as which party must develop the decommissioning plan and at what stage of project development, and the bill does not identify who is responsible for decommissioning costs including disassembly, demolishing, and removing wind turbine components, and any site restoration requirements pursuant to local ordinances.

(4) Use of Indexed REC Structure

Section 1-75(c)(1)(G)(v) of the IPA Act requires the IPA to use an Indexed REC price structure for all of the Agency's competitive procurements and any procurements of RECs from new utility-scale wind and new utility-scale photovoltaic projects. Under this Indexed REC structure, bidders offer a strike price, which is a contract price for energy and renewable energy credits, akin to an all-in price for RECs and energy. The resulting REC price constitutes the difference resulting from subtracting the strike price from the index price for that settlement period, with the index price representing the real-time energy settlement price at the applicable Illinois trading hub. Under the law, "[i]f this difference results in a negative number, the [buyer] shall owe the seller the absolute value multiplied by the quantity of energy produced in the relevant settlement period" but "[i]f this difference results in a positive number, the seller shall owe the [buyer] this amount multiplied by the quantity of energy produced in the relevant settlement period."[73] As HB 2132 proposes the procurement of RECs from a new utility-scale wind project and does not provide for alternative contracting procedures, this existing language in Section 1-75(c)(1)(G)(v) of the IPA Act would govern, and an Indexed REC structure would be used to procure at least 700,000 RECs delivered annually for at least 20 years from one new utility-scale offshore wind project.

(a) Equity and Inclusion Plan Scoring for Offshore Wind Project Selection

HB 2132 proposes requiring an equity and inclusion plan and project labor agreement for awarded utility-scale offshore wind REC contracts. The equity and inclusion plan would be

[72] Tracking systems, such as GATS and M-RETS, serve as registries for tracking the creation, transfer, and retirement of RECs.

[73] 20 ILCS 3855/1-75(c)(1)(G)(v)(1).

aimed at creating job opportunities for underrepresented populations in addition to equity investment eligible communities,[74] and would require a fully executed project labor agreement. Thus, any applicant submitting a proposal to the Agency in response to a new utility-scale offshore wind procurement would be required to first submit to DCEO a separate application for equity and inclusion plan scoring.[75] DCEO would then provide equity and inclusion plan scoring to the Agency upon the Agency's request.

To award a REC contract in a new utility-scale offshore wind procurement, HB 2132 requires that the Agency use point-based scoring criteria, totaling 100 points, in evaluating an applicant's proposal, and no REC contract would be awarded to an applicant who fails to receive at least 75 points:

- 33 points attributed to the price submitted in such proposal, with a lower price being more favorable;
- 33 points attributed to the overall viability of applicant and its plan to build a new utility-scale offshore wind project, as determined by the Agency;[76] and
- 34 points: attributed to equity and inclusion plan scoring.

ii) How IPA Procurement Interacts with Illinois Rust Belt to Green Belt Fund to Support Development

Lastly, HB 2132 creates a special state fund in the Illinois State treasury: the Illinois Rust Belt to Green Belt Fund. It appears that this fund would be used to receive federal funding specifically, although transfers could be taken "from any source, public or private." Managed by DCEO, deposits into the Illinois Rust Belt to Green Belt Fund could then be leveraged for purposes including "financial assistance related to construction of ports and infrastructure" and "workforce development related to offshore wind."

[74] "Equity investment eligible communities" means "equity investment eligible community" as defined in Section 5-5 of the Energy Transition Act. This is a potentially broader definition than "environmental justice communities," and P.A. 103-0580 expressly seeks that impacts on environmental justice communities be analyzed as part of this Policy Study.

[75] HB 2132 defines "Equity and inclusion plan scoring" as a score of up to 34 points, determined by the Department of Commerce and Economic Opportunity's review of an applicant's ability to demonstrate it has a comprehensive and detailed equity and inclusion plan crafted to create opportunities for underrepresented populations in addition to equity investment eligible communities.

[76] The Agency will determine viability of the applicant's plan if the application (a) has identified and proffered a rationale for a site for its new utility-scale offshore wind project and has a comprehensive plan to develop, construct, own, and operate the project; (b) experience and knowledge, or any of the applicant's affiliates have experience or knowledge, in owning offshore wind projects; (c) has a fully executed project labor agreement with the applicable local building and construction trades council; (d) has a comprehensive plan to maximize local economic impact and job creation; (e) has submitted a financing plan showing the financial ability to build, own, and operate a new utility-scale offshore wind project, examples of which may include, but are not limited to: (i) sources of debt, (ii) letters of reference from a commercial bank, or (iii) an equity commitment letter from a parent company; (f) has a comprehensive plan to conduct essential research around the compatibility of offshore wind and the lake ecology and historical lake uses that can become the basis for future decision making around prudent expansion of offshore wind into Lake Michigan; (g) has a plan to mitigate local landward environmental impacts that may otherwise result from construction of a new utility-scale offshore wind project; (h) has a plan to obtain a permit pursuant to the Rivers, Lakes, and Streams Act from the Department of Natural Resources; and (i) fully intends on complying with the Lake Michigan Wind Energy Act and all rules and regulations of the Environmental Protection Agency.

c) Procuring RECs from High Voltage Direct Current Line (SOO Green)

i) Reliance on a Draft Bill

The many changes found in Public Act 102-0662 include new allowances for the procurement of HVDC RECs. Specifically, Sections 1-75(c)(1)(I) and (J) of the IPA Act were revised to support utility-scale renewable energy projects utilizing HVDC transmission lines and converter stations. Section 1-75(c)(1)(I) states that: if (i) a new HVDC transmission line ends at a converter station located in Illinois and interconnected in the region of the PJM interconnection, (ii) was constructed using a project labor agreement, (iii) is capable of transmitting electricity at 525 kV, (iv) does not operate as a public utility, and (v) was energized after June 1, 2023, then the RECs associated with any renewable energy transmitted over that HVDC transmission line with a verified customer in Illinois will be deemed to have been sourced from a generation facility in Illinois for purposes of RPS qualification.[77] These allowances would allow for renewable energy generation facilities located outside of areas considered "RPS eligible" to generate RECs eligible for RPS compliance should the aforementioned criteria be met.

As a comprehensive bill for supporting a new HVDC transmission line was never formally proposed during the Spring 2023 Legislative Session, the Agency's understanding of the HVDC transmission line proposal outlined in P.A. 103-0580 is based on a draft bill circulated by SOO Green HVDC Link. The sections below include an overview of that bill, and by extension, outline assumptions made about the project itself and the mechanisms used for its support for modeling and analysis purposes.

ii) Substance of Proposal

(1) Procurement Target: Frequency of REC Procurement Events and RECs Not Counted Toward Illinois RPS Goals

The legislative proposal (the "HVDC bill") analyzed in this Policy Study was developed against the backdrop of these existing allowances. Under this proposal, the Agency would be required to develop a one-time HVDC REC procurement plan within 120 days of the bill's enactment to procure RECs from new HVDC transmission lines for delivery starting on or about June 1, 2029 for at least 25 years.[78] Notably, however, the HVDC bill's proposed

[77] 20 ILCS 3855/1-75)(c)(1)(I)-(J).

[78] The draft bill would also amend Section 1-10 of the IPA Act to define "High voltage direct current transmission facilities" as the collection of installed equipment that converts alternating current energy in one location to direct current and transmits that direct current energy to a high voltage direct current converter station using Voltage Source Conversion technology. "High voltage direct current transmission facilities" includes the high voltage direct current converter stations and associated high voltage direct current transmission lines. Notwithstanding the preceding, after the effective date of this amendatory Act of the 102nd General Assembly, an otherwise qualifying collection of equipment does not qualify as high voltage direct current transmission facilities unless: (i) its developer entered into a project labor agreement, (ii) more than 100 miles of its Illinois footprint is built underground, (iii) the facilities are capable of transmitting electricity at 525kv or above, and (iv) the facilities include an Illinois converter station physically located in and interconnected in the Illinois footprint of PJM Interconnection, LLC, and the system does not operate as a public utility in Illinois, as that term is defined in Section 3-105 of the Public Utilities Act.

amendment to Section 1-75(c)(1)(C)(i) of the IPA Act outlines that the Agency's HVDC REC procurements would not count toward the State's RPS compliance, meaning that the allowances found in the prior-passed HVDC REC text would seemingly not be implicated.

(2) Financing

The HVDC bill proposes adding subsection (i-5) to Section 16-108 of the PUA, which would allow an electric utility to recover all of the costs associated with HVDC REC contract payments through tariffed charges added to the electric utility's delivery services customers' bills on a per-kilowatt-hour basis for all kilowatt-hours delivered by the electric utility to its delivery services customers. The electric utility's proposed tariff, called the Dispatchable and Reliable Renewable Energy Charge, would be required to conform to Section 1-75(c-7) of the IPA Act and would need to be filed with the Commission on or before February 1, 2024, and the Commission would then review the proposed tariff on or before January 1, 2025 – apparently meaning that ratepayer collections authorized under the HVDC bill would commence well before the construction of the HVDC line itself or any of the renewable energy generating facilities whose generation would produce HVDC RECs.

Electric utilities' tariffed charges for HVDC REC procurements would be funded solely by revenues collected through the Dispatchable and Reliable Renewable Energy Charge. Utilities' HVDC REC procurements would not be funded by revenues collected through any of the other funding mechanisms and would not be subject to the limitation imposed by Section 1-75(c) of the IPA Act on charges to retail customers for costs to procure renewable energy resources. Further, the utilities' proposed tariff would be required to provide that any excess or shortfall of collections would be deducted from or added to, on a per-kilowatt-hour basis, the Dispatchable and Reliable Renewable Energy Charge over the six-month period beginning October 1 of that calendar year. Unlike HB 2132 discussed above, the HVDC bill does not propose rate impact caps to charges on retail customers for HVDC REC procurements.

(3) Use of Indexed REC Structure

The HVDC bill proposes to amend Section 1-75 of the IPA Act to add subsection (c-7)(4) outlining that the Agency's HVDC REC procurement plan must use an Indexed REC structure described in Section 1-75(c)(1)(G)(v)of the IPA Act, which is administered by the Agency's Procurement Administrator. Under this approach, owners or operators of eligible HVDC transmission lines would bid in a "strike price" representative of both the HVDC REC price and assumed wholesale market revenues, with actual HVDC REC prices determined through subtracting an Index Price from the strike price. Resulting HVDC REC contracts must be for at least 25 years in length.

While the HVDC bill proposes that a benchmark apply to the maximum acceptable HVDC REC strike price, the bill does not propose that this price be developed by the Agency's Procurement Administrator and submitted to the ICC for its approval. Instead, the HVDC bill proposes that the State's Capital Development Board "shall calculate a range of capital costs that it believes would be reasonable for an HVDC transmission line of similar specifications to an applicant high voltage direct current transmission line and "may consult as much as it deems necessary with applicant or potential applicant high voltage direct current transmission lines" in determining the "capital and O&M costs" used by the Procurement Administrator in benchmark development. This is a highly unusual approach; the Agency has never before worked with the Capital Development Board in any of its program and procurement initiatives and does not allow such direct consultation with bidders or applicants in establishing benchmark prices. Additionally, the HVDC bill does not appear to require that resulting benchmarks be confidential, although terms of sale of the RECs would apparently be required to be kept confidential.

Additionally, the HVDC bill proposes to allocate HVDC REC purchase obligations to electric utilities based on their respective percentages of kilowatt-hours delivered to delivery service customers to the aggregate kilowatt-hour deliveries by the electric utilities to delivery services customers for the year ended December 31, 2021. Thus, while the HVDC bill serves to bring power from MISO into PJM to serve PJM customers, costs for supporting this project would be assigned to both ComEd (PJM) and Ameren Illinois (MISO) ratepayers.

(4) REC Delivery Requirements

The HVDC bill would require the Agency's HVDC REC procurement plan to include a target volume to procure at least 12,500,000 HVDC RECs delivered annually. The HVDC REC contracts would contain terms for REC delivery to begin on the later of June 1, 2029, and energization of the associated HVDC transmission line, with additional reasonable extensions available for delays in energization of the generation facility. Additionally, the contract would need to provide that the contract term must be selected by the bidder to be between 25-40 years. Further, while the bill provides that the HVDC REC procurement plan must include a contingency plan if the Agency procures less than 12,500,000 HVDC RECs annually or if one or more winning bidders fails to delivery HVDC RECs,[79] there is no guidance in the bill on how this contingency plan should be structured or what considerations must be contained in the contingency plan.

(a) Sources of Energy Generation for RECs

The HVDC bill proposes to add subsection 1-75(c-7) (4)(iii) of the IPA Act to provide that the Agency's HVDC REC procurements must come from solar photovoltaics or wind, but if solar photovoltaics or wind do not provide enough sufficient HVDC RECs, the Agency may procure HVDC RECs from other fuel types that qualify as a renewable resource under Section 1-10 of the IPA Act.

More generally, the HVDC bill does not bind a participant HVDC transmission line – such as the SOO Green project – to derive its RECs from any specific generating technologies. To the

[79] The number of HVDC RECs to be procured shall not be reduced based on RECs procured in the Self-direct REC compliance program established pursuant to Section 1-75(c)(1)(R) of the IPA Act.

contrary, the bill allows that upon notice to the Agency, the generation source or anticipated generation source of any HVDC RECs may be changed. This is an important facet of the bill. While proponents behind the SOO Green project have supplied the Agency with assumptions about the generating mix fueling SOO Green to be used in modeling and analysis, a different mix of generation may create a very different project and value proposition. For example, SOO Green proponents have asked that the Agency assume that its transmission line sources power from a mix of Iowa-based wind, solar, and storage resources. Were the project to be supported using only wind facilities with no storage, for example, both the project's resulting capacity factor and assumed accreditation in capacity markets by PJM would be substantially reduced versus what SOO Green's proponents claim and what the Agency has modeled.

(b) Energy Generation Terms of Sale

The HVDC bill does not propose requirements around the sale of energy or capacity from generation transferred through the HVDC line, and the line's operator would be free to enter into bilateral off-take agreements or sell into wholesale markets as it wishes under the bill. Instead, the HVDC bill proposes only the procurement of HVDC RECs at a price established through a procurement process outlined in the bill, with RECs priced under an Indexed REC structure and revenues from the sale of RECs presumably used to subsidize the SOO Green project's development and operation. Those RECs would be retired by a counterparty electric utility, but HVDC REC retirements would not be used to satisfy the State's RPS requirements outlined in Section 1-75(c) of the IPA Act.

More specifically, the HVDC bill would require HVDC REC contracts to contain the following terms of sale: monthly payment for RECs actually delivered (not to exceed on a three-year rolling average basis 120% of the annual delivery quantity bid); a reasonable minimum annual delivery quantity of HVDC RECs (no penalties would be assessed in the event of force majeure); reasonable performance assurance and credit requirements; all HVDC RECs delivered would be required to be generated from a system that is energized or repowered on or after the bill's effective date; and allow at any time after selection, the winning bidder may change, upon notice to the Agency, the generation source or anticipated generation source of any HVDC RECs.

(c) Bid process for RECs

The HVDC bill also includes that the Agency's HVDC REC procurements would generally be procured in accordance with the Agency and Commission's processes for competitive procurements in Sections 16-111.5(e)-(p) of the PUA. The Agency's HVDC REC plan would require that only the owner or operator[80] of a HVDC transmission line or its designee may

[80] The owner or operator (or the designee of the owner or operator) must demonstrate that it has site control of at least 90 miles route located within Illinois, and plans reflecting 525 kV or greater delivery voltage and construction of at least 100 miles of transmission line underground in Illinois. "Site control" may include easements, leases, options for leases, or any similar indicia of site control identified by the Agency.

be allowed to bid in the competitive HVDC REC procurements, with each bid for a quantity of not less than 5,000,000 HVDC RECs annually.[81]

Additionally, each competitive bid would be required to specifically identify the price charged by the HVDC transmission line (which would presumably be the strike price under an indexed REC stricture). The bill proposes that all information about HVDC transmission line pricing would be maintained as highly confidential and not disclosed by the Agency, Commission, or any third party otherwise privy to such information. The bill also specifies that the Agency's HVDC REC procurement plan would allow the owner or operator, or the designee of the owner or operator, to enter multiple bids, provided that the same bid does not include HVDC RECs[82] pledged in another bid.

[81] The Agency must only procure cost-effective HVDC RECs. "Cost-effective" means the HVDC RECs shall not exceed benchmarks based on market prices for HVDC RECs.

[82] The bill states that the Agency's HVDC REC procurement plan shall not, subject to the preference for solar photovoltaic and wind generation, prohibit or penalize any RECs that meet the definition of high-voltage REC in the IPA Act.

4) Methodology

a) Use of Procurement Planning Consultant

i) Structure

Public Act 103-0580 directs the Agency to retain the services of technical and policy experts with energy market and other relevant fields of expertise. The Agency has utilized its existing Planning and Procurement Consultant, Levitan and Associates, Inc. ("Levitan"), and several subcontractors to conduct the study.[83] The Agency commissioned Levitan and the subcontractors to run simulations that would estimate the outcomes associated with implementing the projects imagined in the three proposals. Models use known inputs to explain and predict the likelihood of future outcomes. These models considered the impacts of the proposals on the electrical grid, electricity markets, resource adequacy, overall emissions, state economy, and other factors.

ii) Planning and Procurement Consultant Experience

Levitan has extensive experience and expertise involving wholesale power market design, administrating, and monitoring of power supply solicitations and procurements, and a wide range of issues related to wholesale market planning and supply portfolio design, including transmission planning and risk management. Additionally, Levitan has expertise in wholesale electricity market rules and broad regulatory experience through being involved in FERC proceedings and through assignments involving regional transmission operators ("RTOs") throughout North America. Levitan also has expertise involving the structuring of renewable energy procurements, evaluating offshore wind projects,[84] benchmarking renewable REC prices, and deriving the levelized net cost of electricity to ratepayers.

The IPA has worked with Levitan when developing nine of Agency's annual electricity procurement plans (annual plans from 2016-2024);[85] four of the Agency's Long-Term Plans (the first Long-Term Plan (2018), the Revised Long-Term Plan (2020), the 2022 Long-Term Plan, and the 2024 Long-Term Plan);[86] and the 2017 Zero Emission Standard Plan, and the

[83] 20 ILCS 3855/1-75(a)(1). The IPA Act directs that the Agency use experts or expert consulting firms, known as the Planning and Procurement Consultant, to help develop its annual electricity procurement plan.

[84] Levitan has served in active role in offshore wind procurements in New England, New York, New Jersey, and Maryland.

[85] The Agency's annual electricity procurement plan analyzes the projected balance of supply and demand for eligible retail customers over a 5-year period; identifies the wholesale products to be procured following plan approval by the Illinois Commerce Commission; analyzes the impact of any demand-side and renewable energy initiatives. https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html.

[86] The Agency's Long-Term Renewable Resources Procurement Plan analyzes load forecasts, calculates RPS budgets and targets at the utility and Statewide levels, establishes the REC Pricing Model for the Agency's Programs, and analyzes contracted REC quantities and prices to estimate available budgets and gaps. https://ipa.illinois.gov/energy-procurement/plans-under-development.html; https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html.

2021 Carbon Mitigation Credit Procurement Plan.[87] Levitan has also assisted the IPA with developing its 2016-2023 Annual Reports on the Agency's operations and transactions.[88]

Previously Levitan served as the IPA's Procurement Administrator for the 2008, 2009, 2010, 2011, and 2012 procurements of energy, capacity, and RECs for the eligible retail customers of Ameren Illinois. Additionally, Levitan served as the Procurement Administrator for the IPA's Long-term Renewable Energy procurement for Ameren Illinois in December 2010, managing the procurement process, including building and maintaining a secure website; contacting, qualifying, and registering bidders; preparing a timeline; drafting RFP documents; preparing standard contracts and credit agreements; developing confidential price benchmarks; advertising the solicitations; answering questions; constructing computer-based bid models to evaluate bids; and reporting the bidding results and bid acceptance recommendations to the ICC.

(1) Role

The Agency engaged Levitan to undertake the modeling and analytical work necessary to conduct the Policy Study. Levitan's work for the Policy Study included developing a technical report explaining the results and impacts of Aurora production cost simulation modeling to evaluate the impacts on electricity rates and generation-related emissions and IMPLAN economic modeling to evaluate the impacts on employment and the State's economy.

(2) Use of Procurement Plan Consultant Subcontractors

(a) Structure

Levitan engaged subcontractors, GE Energy Consulting and ENTRUST Solutions Group, to provide reliability simulation modeling to evaluate the impacts on energy generation reliability and resource adequacy, and to provide power flow modeling to evaluate the impacts on grid reliability.

(b) Qualifications and Role

GE Energy Consulting, which is part of the GE Power business, provides electric power systems engineering and economic consulting services. GE Energy Consulting provides services to government agencies, government and investor-owned utilities, system operators, independent power producers, power distribution companies, and load-serving entities. GE Energy Consulting's services include performing studies of the impact of proposed generation or transmission projects on transmission reliability, often with specific

[87] The Agency's Zero Emission Standard Procurement Plan and the Carbon Mitigation Credit Procurement Plan set out the provisions for the procurement of Zero Emission Credits or Carbon Mitigation Credits. These credits recognized the environmental benefits of nuclear electric generation resources that do not emit carbon dioxide or other key pollutants. https://ipa.illinois.gov/energy-procurement/prior-approved-plans.html.

[88] https://ipa.illinois.gov/about-ipa/ipa-publications.html

attention to the unique characteristics of variable wind and solar projects. GE Energy Consulting's sub-specialties include: Power Economics; Power Systems and Operation Planning; Generation Products and Services; Power Systems & Energy Course; and Modeling Software, GE's Multi-Area Reliability Simulation (GE MARS).[89] For the Policy Study, GE Energy Consulting utilized industry standard modeling tools including GE MARS to evaluate the impacts on generation reliability and resource adequacy and used reliability simulation modeling to evaluate the impacts on generation reliability and resource adequacy.

ENTRUST Solutions Group provides comprehensive transmission system analysis and planning services that analyze, identify, explain, and solve complex technical issues for transmission owners. The company also assists its clients in navigating RTO policies affecting grid planning. ENTRUST Solutions Group's services include power flow modeling for interconnection analysis's regional reliability analysis, and planning support for RTOs and ISOs. For the Policy Study, ENTRUST Solutions Group used PSS/E and TARA to evaluate the impacts on transmission reliability and grid resilience; and used power flow modeling to evaluate the impacts on grid reliability.

b) Process

Upon commencement of the Policy Study, the Agency requested technical information from advocates of the offshore wind and high-voltage transmission proposals and representatives from the electricity storage industry. This information helped the Agency, and its contractors develop assumptions about the three policy proposals that Levitan and its subcontractors modeled for impacts. Tables 4-1, 4-2, and 4-3 show the information requested of and received by the parties directly associated with these policy proposals, as well as assumptions made in lieu of specific guidance.

[89] The GE-MARS Simulation software program provides many valuable metrics of system reliability, including Loss of Load Expectation (LOLE) and Effective Load Carrying Capability, and the frequency of grid outages. GE Energy Consulting has used GE-MARS to perform probabilistic and resource-adequacy analysis in many different areas including planning, resource adequacy, reserve margin analysis, and capacity value of wind/solar.

Table 4-1: Information Requested of HVDC Transmission Line Advocates

Information Requested	Response
Injection Amount	Up to 2,100 MW
Energy Mix	5,150 MW of firmed energy made up of: 2,300 MW West-Central Iowa wind 350 MW Central Iowa wind 1,850 MW Central Iowa solar 650 MW 4-hour duration energy storage
Electrical Locations of the two ends of the HVDC Line	The SOO Green HVDC line will consist of two converter stations total, one at each end of the link, which will be connected by 350 miles of underground cable. In Iowa, the converter station is located close to Mason City (Latitude: 43° 8’11.99”N, Longitude: 93°17’35.37”) In Illinois the Converter is located close to the city of Plano (Latitude: 41°41’14.81”N, Longitude: 88°28’47.70”W)
Point of Interconnection of the HVDC Line	Iowa: Taps into the Colby – Killdeer 345 kV line, 3 miles north of Killdeer 345 kV substation Illinois: Will interconnect with the ComEd transmission system by tying to a 345 kV bus at TSS 167 Plano, ComEd’s 345 kV Plano Substation

Table 4-2: Information Requested of Offshore Wind Advocates

Information Requested	Response
Injection Amount	200 MW
Plant Location and Point of Interconnection	Information provided in the stakeholder response to the IPA's request for information did not provide any specific location or points of interconnection for the plant other than to say that the eventual siting of the offshore wind project on Lake Michigan will depend upon many factors, including siting constraints identified by the Illinois Department of Natural Resources ("IDNR"), which include water depth, distance from shore, proximity to grid interconnection points, etc. [90] The response also referred to a map prepared by the IDNR which circled preferred areas for points of interconnection near the shore: the north shore and south shorelines.[91]

Since the advocates did not specify a particular interconnection point or site location for the proposed offshore wind project the Agency subsequently met with a prospective developer of the offshore wind project who provided five points of interconnection as shown in Table 4-3. The Agency studied these points of interconnection in the Policy Study.

[90] "Many developers are likely to respond to a forthcoming solicitation resulting from the potential passage of HB 2132, each of which will present its own distinctive strategies, plans, cost evaluations, and other pertinent elements. The comprehensive development work essential for crafting these proposals will not be initiated until the official enactment of HB 2132 and the imminent launch of the solicitation process. Consequently, a substantial portion of the specific information defining a potential offshore wind project has yet to materialize. Even more detailed information will not be generated until the winning developer begins development of its project. However, there is much that can be said about the general characteristics of a potential a utility-scale offshore wind project situated in the Illinois waters of Lake Michigan, as contemplated in HB 2132."

[91] Appendix B, pg. 12

Table 4-3: Assumptions for Offshore Wind Points of Interconnection

Facility Name	kV	Capacity (MW)
Stateline Substation **(Primary)**	138	200
Calumet Substation **(Secondary)**	138	200
North Harbor Substation **(Secondary)**	138	200
Stateline Substation **(Secondary)**	345	200
Calumet Substation **(Secondary)**	345	200

For energy storage, the Agency communicated with stakeholders in the energy storage industry and a trade organization that represents several Illinois-based companies in the field. As this policy proposal is not designed to support a specific set of projects, the Agency sought out diverse views on where and how storage would be developed to inform analyzing how an influx of at least 7,500 MW of energy storage systems would affect the Illinois grid, environment, and economy.

When asked for input on how the Agency should best estimate the likely locations and interconnection points for future energy storage projects, stakeholders recommended that the IPA use the battery energy storage projects already in the PJM and MISO queues as indicative locations of large-scale battery storage facilities that could be built to meet the target capacities set forth in SB 1587.

Table 4-4: Assumptions Made About Energy Storage (Utility-Scale)

Topic	Assumption
Storage Technology	Lithium-ion batteries
Percentage split between RTO regions	70% in Central/Southern IL (MISO) 10% in Chicago (PJM) 20% Northern IL outside Chicago (PJM)
Total MW Installed	1,500 MW by 2030 7,500 MW by 2040 [92]
Resultant Allocation	5,250 MW in Central/Southern IL (MISO) 750 MW in Chicago (PJM) 1,500 MW Northern IL outside Chicago (PJM)
Likely Project Locations and Interconnection Sites	Sites were estimated using the current energy storage projects in the PJM and MISO queues.[93] Based on the MISO allocation of 5,250 MW, a list of 35 points of interconnection were determined, with some project capacities adjusted to match the required allocation.[94] Based on the PJM allocation of 750 MW for Chicago, IL, and 1,500 MW for the rest of PJM, 10 locations were determined, with some project capacities adjusted to match the required allocation.[95]

While SB 1587 also contains proposals to promote the development of storage paired with distributed generation projects and community solar projects, those proposals do not target a specific quantity of new project deployment or specify a timeline for new project rollout. Instead, those proposals simply call for the filing of tariffs with the Illinois Commerce Commission providing compensation back to the owners or operators of these storage projects for satisfying certain criteria. The specific compensation levels (and thus impact on

[92] While SB 1857 envisions 7,500 MW of procurement completed by 2030,

[93] MISO queue can be found at https://www.misoenergy.org/planning/resource-utilization/GI_Queue/, and the PLM queue can be found at https://www.pjm.com/planning/service-requests/services-request-status.

[94] Appendix B, p. 19.

[95] Appendix B, p. 25.

the economics of these small-scale storage projects) would be determined through ICC proceedings.

In the absence of any information about at what level project owners would be compensated, the IPA cannot comfortably estimate what levels of new small-scale storage projects could result from these tariffs being implemented. Nevertheless, the IPA has endeavored to model the impact on storage project deployment resulting from these proposals. After review and analysis of the small-scale storage targets found in other states, the Agency elected to assume an additional 1,000 MW of distributed storage deployment in addition to the 7,500 MW of utility-scale storage proposed in SB 1587. This added distributed energy storage is included in the modeling of impacts on the economy, jobs, energy costs, and emissions. However, the added distributed energy storage is not included in modeling of impacts generation reliability, resource adequacy, transmission reliability, and grid resilience; this is because distributed energy storage is connected to the distribution grid and not the transmission grid (and the modeling tools used to measure those impacts are designed to analyze the transmission system).

c) General Stakeholder Outreach

Parallel to its efforts to engage with interested parties having direct information about resultant projects, the Agency conducted a broader stakeholder feedback process to ensure that the Agency was considering all interested parties' viewpoints when determining the assumptions modeling.

On September 29, 2023, the Agency published a request for feedback to the Agency's email list and on its website. The Agency received input from a diverse set of parties, including labor organizations, industry associations, environmental groups, and concerned individuals. All input was shared with Agency consultants, posted on the Agency's website, and considered in discussion with consultants throughout the research and modeling process.[96]

On January 22, 2024, the Agency released a draft version of the Policy Study for public comment. After determining that there were errors in the presentation of certain modeling results, the Agency published an errata on February 8, 2024 detailing the errors and presenting updated values. In an effort to give commenters time to address the corrections and to understand the underlying work, on February 13, 2024, the Agency both extended the deadline for comments by two weeks and published additional workpapers on its website. Further discussion of the errata and comment process can be found in Section 2.c.ii.

The Agency received written comments from twenty-three stakeholders by the initial February 12, 2024 deadline and received comments from two additional stakeholders by the extended deadline of February 26, 2024. Three stakeholders who provided initial comments

[96] The Agency's call for feedback: at https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20230929-ipa-policy-study-general-information-request.pdf. Responses received: https://ipa.illinois.gov/ipa-policy-study/stakeholder-feedback-on-ipa-policy-study.html.

also provided supplemental comments. All comments were posted online and reviewed by the Agency which has endeavored to address the feedback in the final version of this Policy Study.

d) Agency Research

Within the Agency, IPA staff conducted a comparative analysis of the three proposal topics, researching how other states have addressed these topics through legislative or executive action. Agency staff studied existing programs and policies from several states, including California, Maryland, Maine, New Jersey, and New York.

IPA staff also reached out to public agencies and commissions within Illinois and elsewhere in the US for information, including:

- Illinois Environmental Protection Agency
- Illinois Department of Natural Resources
- Illinois Commerce Commission
- Illinois Department of Commerce and Economic Opportunity
- Wisconsin Department of Natural Resources

e) Models

Table 4-5 summarizes the contractors, the models used, and the outcomes measured by the model.

Table 4-5: Modeling Contractors

Contractor	Model Used	Policy Impacts Studied
ENTRUST Solutions	Siemens PTI PSS®E and PowerGEM TARA	Power flow and reliability
Levitan and Associates	Aurora	Energy and Capacity Prices, Emissions,
Levitan and Associates	IMPLAN	Economic Development
GE Energy Consulting	GE MARS	Grid reliability and resource adequacy

i) Model 1: Siemens PTI PSS®E and PowerGEM TARA

Siemens PTI PSS®E and PowerGEM TARA are steady-state power flow software tools which are widely licensed and used by transmission organizations and are critical parts of several production tool chains for planning and operations in the US.

A power flow study is a numerical analysis of the flow of electric power in an interconnected system. Siemens PTI PSS®E and PowerGEM TARA use power flow calculations to analyze a power system in normal steady-state operation, then simulate scenarios that could adversely affect the operation of the system, such as downed transmission lines, equipment failures or generating plant outages. These losses of electrical components, known as contingencies, have a chance of causing the transmission system to carry electric flow beyond its safe limits, causing a violation.

The goal of the power flow analysis is to identify the potential contingencies that could be caused by the interconnection of the resources associated with the three policy proposals under study. The power flow modeling identifies and evaluates the contingency conditions and provides estimates for the costs of system improvements that would be necessary to mitigate the contingency conditions. The costs of the network upgrades are determined by the size of the impact that a resource seeking interconnection has on the system. The larger the impact, the higher the network upgrade costs.

ii) Model 2: Aurora

Aurora is a production simulation model that is widely used in the power industry. Production simulation models estimate the cost of electricity and simulate the operation of generation and transmission systems under a specified set of assumptions about electricity demand, fuel prices, generation resource mix, and operating performance.

For this study, the Aurora model was used to analyze the policy proposals' impacts on wholesale electricity prices, emissions, and changes to the composition and operation of the generation resource mix in Illinois over the modeling time horizon.

Production simulation models start with a base case of the regional electric system: its generation resources, costs, loads, operational characteristics, and environmental and other regulatory considerations.

After the base case has been defined, the model then simulates how the electric system will operate with the addition of the new facilities or under the proposed policies. A comparison of the simulation results with the base case provides a picture of how these additions would change the way the electric system operates, the mix of generation resources, and the cost of generating electricity.

In this Study, all dollar values, unless otherwise noted, are conveyed in nominal dollars. In some instances, real dollars, or constant dollars, are used.[97] Real dollars are adjusted for their purchasing power in a given year, usually (and in this analysis) controlling per inflation. The long-term inflation assumption used in this analysis was 2.5% for converting constant dollar values to nominal values, consistent with the NREL Annual Technology Baseline ("ATB"). Given the long time horizon for this study, the compounding effect of inflation means that a

[97] United States Census Bureau, Current versus Constant (or Real) Dollars, accessed February 27, 2024. Current versus Constant (or Real) Dollars (census.gov)

nominal dollar in the beginning of the study period is likely to be worth more in real dollar terms than a nominal dollar at the end of the study period.

For example: assume a customer's electric bill in 2022 is $100 and remains the same price of $100 in 2023. In this case, there is no nominal price change in electricity prices (pays $100 in 2022 and $100 in 2023). To capture price change in electricity, we calculate the real value of prices in 2022 (accounting for deflation). If we assume that the deflation rate is 2%, then $100 in 2023 would be equivalent to $102 in 2022. Instead of the customer paying $102 in 2023, they are paying $100, signifying a reduction in electricity prices.

Economists generally prefer real prices over nominal prices because real prices account for changes in purchasing power due to inflation or deflation. Nominal prices are the actual prices of goods and services in current currency units, whereas real prices are adjusted for changes in the general price level. Including the effects of inflation or deflation provides a more accurate picture of real prices. When evaluating the effectiveness of economic policies or conducting macroeconomic analysis, using real prices helps to understand the true impact of policy changes on consumers, producers, and the overall economy. Nominal prices in these contexts do not account for changes in the value of money.

iii) Model 3: IMPLAN

IMPLAN is a leading provider of economic impact data and analytical applications. IMPLAN utilizes an economic modeling technique called Input-Output analysis and a Social Accounting Matrix, which tracks the interdependence among various producing and consuming industries of an economy and the spending of households. It measures the relationship between a given set of demands for final goods and services and the inputs required to satisfy those demands.

To test the economic impact of a new policy change or investment in IMPLAN, the initial economic impact associated with the new policy change or investment is entered into IMPLAN as a one or more monetary values and corresponding IMPLAN industries that specify which parts of the economy are initially affected. The IMPLAN model then tracks the economic impacts through an economy using its proprietary multipliers, estimating the total effect to the economy resulting from the initial economic impacts. For each policy case in this study, the inputs cover construction, known as Capital Expenditure or "CapEx", and 20 years of operation, known as Operating Expense or "OpEx."

iv) Model 4: GE MARS

GE MARS assesses the impact the policy proposals would have on system resource adequacy in the years 2030 and 2040. Resource adequacy is the ability of an electric power system to meet demand for electricity—a fundamental component of electric system reliability that is assessed through the use of simulation models. The model measures resource adequacy two ways: through the change in capacity is measured by Effective Load Carrying Capability

(ELCC)[98], and the impact to loss of load, measured in terms of Loss of Load Expectation (LOLE)[99], the industry standard for assessing the impact on reliability.

GE MARS is based on a sequential Monte Carlo simulation,[100] which provides a detailed representation of the hourly loads, generating units, and interfaces between the interconnected areas of Illinois. In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. This allows the system to be modeled in great detail with accurate recognition of random events, as well as deterministic rules and policies, which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

The random events that this GE MARS simulation analysis considered included: load forecast uncertainties, transmission outages, equipment failures that would interrupt transmission or generation, and variable renewable generation such as when the wind stops blowing unexpectedly.

[98] ELCC is a measurement of a resource's ability to produce electric energy when the grid is most likely to experience supply shortfalls, that is the resource's ability to prevent an outage due to a supply shortfall. ELCC is typically represented as a percentage of a resource's capacity.

[99] LOLE is the expected number of days where load cannot be met with available resources. The LOLE determines the numbers of days in which a loss of load (i.e., a power outage/disconnection) would be expected to occur on average across a large number of system conditions. LOLE of 0.1 days/year is a de-facto standard, or criteria, in industry for probabilistic reliability metrics, sometimes referred to as "1 day in 10 years".

5) Energy Storage

a) Energy Storage Market Trends

Energy storage is expected to be a critical component in the transition to increased use of renewable energy sources and to maintain a reliable grid. The United States has witnessed significant growth in energy storage capacity in recent years. Energy storage can take on several forms, with the most common currently being pumped storage (where water is pumped to a higher level and then released to run through a turbine to generate electricity), and batteries. Other types of energy storage can include thermal storage (which store heat), flywheels (which store kinetic energy), and compressed air (potential energy).

In 2022, pumped storage accounted for 67% of storage capacity in the U.S., with the remaining capacity attributed to battery and thermal storage.[101] Among all of the energy storage technologies, lithium-ion battery technology stands out due to its advanced market maturity compared to other emerging technologies.[102] Therefore, the proportion of pumped storage in U.S. dropped from 78% in 2021 to 67% in 2022, a change driven by the rise in large-scale lithium-ion battery installations.[103]

Battery storage capacity in the United States more than tripled in 2021, growing from 1.4 gigawatts ("GW") in 2020 to 4.6 GW.[104] Planned and currently operational U.S. utility-scale battery capacity totaled around 16 GW at the end of 2023. Developers plan to add another 15 GW in 2024 and around 9 GW in 2025, according to the Energy Information Administration ("EIA").[105]

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[101] BloombergNEF, & Business Council for Sustainable Energy. (2023, March 7). Available at: Energy storage made record gains in the US in 2022: Sustainable Energy in America Factbook | Utility Dive

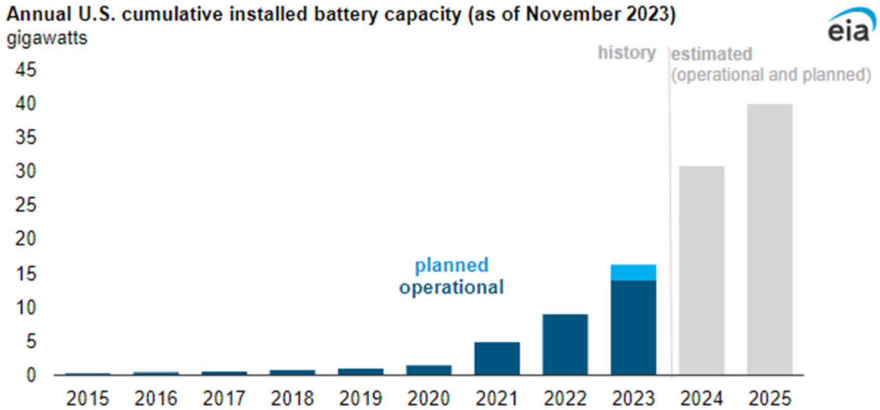
[102] Renewable Energy World. (2021, June 24). Grid-Scale U.S. Available at: Grid-Scale U.S. Storage Capacity Could Grow Five-Fold by 2050 | News | NREL

[103] BloombergNEF, & Business Council for Sustainable Energy. (2023, March 7). Available at: Energy storage made record gains in the US in 2022: Sustainable Energy in America Factbook | Utility Dive

[104] See Utility Dive. (2022, July 5). U.S. energy storage capacity tripled in 2021: EIA. Available at: US energy storage capacity tripled in 2021: EIA | Utility Dive

[105] Preliminary monthly electric generator inventory (based on form EIA-860M as a supplement to form EIA-860). (n.d.). U.S. Energy Information Administration (EIA). https://www.eia.gov/electricity/data/eia860m/

Figure 5-1: U.S. Battery Storage Capacity[106]



According to the Storage Futures Study by the National Renewable Energy Laboratory ("NREL") forecasting the potential growth of grid-scale energy storage in the U.S., deployment for energy storage exceeds 125 GW by 2050, more than a five-fold increase from the installed storage capacity of 23 GW in 2020 (the majority of which is pumped hydro).[107]

A utility-scale/grid-scale energy storage project, defined by a capacity greater than 1 megawatt ("MW"), functions to elevate the reliability of electric power in capture and storage of electricity generation surplus. This storage thereby promotes grid reliability during peak demand times and can alleviate congestion in electricity transmission. The EIA also anticipates a significant increase in national utility-scale energy storage capacity, with 7.8 GW operational as of October 2022 and 30 GW planned by the end of 2025 based on EIA's Preliminary Monthly Electric Generator Inventory.[108] The trend suggests an initial deployment of shorter-duration storage (up to 4 hours), progressing to longer durations as deployment expands.[109] The majority of storage increases come from 4–8-hour battery storage, as indicated by Figure 5-2 below. Long-duration storage contributes to grid stability and reliability by providing a consistent energy supply, while short-duration storage enhances flexibility and responsiveness to meet rapid fluctuations in electricity demand—together ensuring balanced and efficient grid operation.

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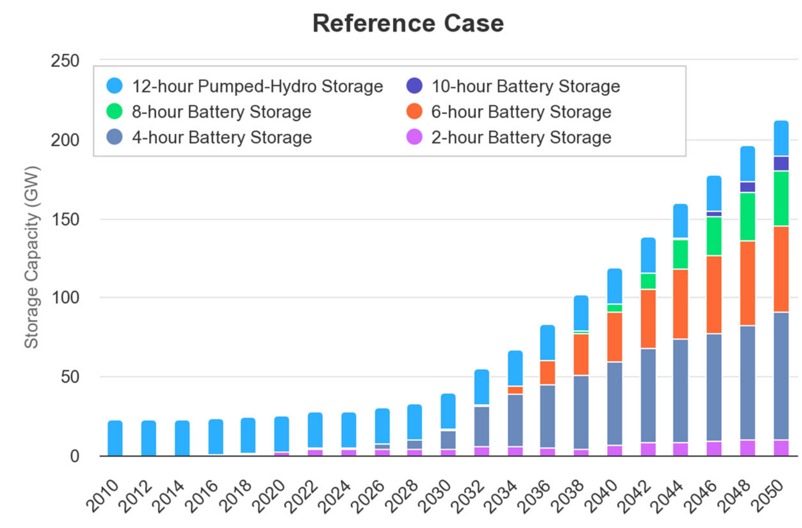
[106] U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, based on Form EIA-860M

[107] Frazier, A. Will, Wesley Cole, Paul Denholm, Scott Machen, Nathaniel Gates, and Nate Blair. (2021). Storage Futures Study: Economic Potential of Diurnal Storage in the U.S. Power Sector [PDF file]. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77449. Available at: [Storage Futures Study: Economic Potential of Diurnal Storage in the U.S. Power Sector (nrel.gov)]

[108] U.S. EIA, "Preliminary Monthly Electric Generator Inventory based on Form EIA-860M as a supplement to FormEIA-860," December 2023. https://www.eia.gov/electricity/data/eia860m/

[109] Frazier, A. Will, Wesley Cole, Paul Denholm, Scott Machen, Nathaniel Gates, and Nate Blair. (2021). Storage Futures Study: Economic Potential of Diurnal Storage in the U.S. Power Sector [PDF file]. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77449. Available at: [Storage Futures Study: Economic Potential of Diurnal Storage in the U.S. Power Sector (nrel.gov)]

Figure 5-2: U.S. Battery Storage Capacity[110]



The EIA report on U.S. Battery Storage Market Trends highlighted three key development trends for battery storage in the U.S. over the past few years.[111] First, there has been substantial growth in both large-scale and small-scale (less than 1 MW of generating capacity) energy storage capacity, with the majority of small-scale energy storage capacity installed in the commercial and residential sectors. As of the end of 2019, more than 60% of the large-scale battery system capacity used to store energy or to provide power to the grid in the United States was located in areas covered by the regional grid operators PJM and California Independent System Operator. 83% of all small-scale battery storage power capacity were in California.

Second, the cost of installing and operating large-scale battery storage systems has declined in recent years. Lower costs support more capacity to store energy at each storage facility, which can increase the duration that each battery system can last when operating at its maximum power. According to a report from Environmental Defense Fund,[112] the cost of energy storage has undergone a substantial 74% decline since 2013. Despite supply chain disruption and geopolitical issues arising in locations where batteries are produced and processed,[113] this downward trajectory is projected to persist through the mid-2020s.[114]

[110] NREL, Grid-Scale U.S. Storage Capacity Could Grow Five-Fold by 2050, June 1, 2021

[111] U.S. Battery Storage Market Trends. (2021, August). U.S. Energy Information Administration (EIA). https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage_2021.pdf

[112] Environmental Defense Fund. (n.d.). Energy Storage. Available at: [The energy storage market booms, with more growth to come - Environmental Defense Fund (edf.org)]

[113] Top 10 energy storage trends in 2023. (2023, January 11). Bloomberg NEF. https://about.bnef.com/blog/top-10-energy-storage-trends-in-2023/

[114] National Renewable Energy Laboratory (NREL) (n.d.) Cost Projections for Utility-Scale Battery Storage: 2021 Update. NERL. https://www.nrel.gov/docs/fy21osti/79236.pdf

Also, investments in energy storage are predicted to soar, with projections indicating a $620 billion increase over the next two decades.

Third, it is expected that more large-scale battery storage systems coming online in the next few years will pair with photovoltaic generation. The potential for energy storage in the U.S. is significant and is closely tied to increasing levels of solar PV penetration on the grid. Notably, over 93% of the battery capacity added in 2021 was co-located with solar installations, exemplifying the industry-wide trend towards integrated renewable and storage capacity growth.[115]

In summary, as more renewable resources are integrated into the grid, the demand for energy storage technologies is likely to increase to stabilize the grid and improve its reliability. The U.S. energy storage market is exhibiting robust growth, driven by technological advancements, supportive policies, and strategic integration with renewable energy sources. These trends position the energy storage market as a key player in the nation's transition towards a more sustainable and resilient energy future.

b) Opportunities of Energy Storage Paired with Renewables

This section provides an overview of the opportunities and benefits of pairing energy storage with renewables as guided by the provisions proposed in SB 1587 and by external research. SB 1587 outlines that the deployment of Energy Storage Systems ("ESS")[116] is necessary to achieve high levels of renewable energy, to avoid the use of peaking fossil fuel plants, and to maintain an efficient, reliable, and resilient electric grid.

Hybrid capacity refers to renewable generation technologies combined with storage. Storage increases the speed of integrating renewable technologies. In 2020, 90% of all hybrid capacity (renewable generator plus energy storage) was in nine states, with Texas accounting for 46% of the total.[117] Energy storage systems are expected to have a place on the grid given that solar is likely to represent more than half of new electric-generating capacity in 2023.[118]

According to a study by NREL, as a widespread transition to distributed energy resources ("DERs") takes place, state and federal policymakers have also set ambitious energy and climate goals, and enacted regulations that fuel the adoption of DERs.[119] For example,

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[115] U.S. Energy Information Administration. (2022, July 5). U.S. energy storage capacity tripled in 2021: EIA [Press release]. Utility Dive. Available at: [US energy storage capacity tripled in 2021: EIA | Utility Dive]

[116] Energy Storage Systems for electricity generation uses electricity (or some other energy source, such as solar-thermal energy) to charge an energy storage system or device, which is discharged to supply (generate) electricity when needed at desired levels and quality. https://www.eia.gov/energyexplained/electricity/energy-storage-for-electricity-generation.php.

[117] U.S Energy Information Administration (EIA), "Large battery systems are often paired with renewable energy power plants (May 18, 2020)" available at: https://www.eia.gov/todayinenergy/detail.php?id=43775

[118] U.S Energy Information Administration (EIA), "More than half new U.S electric-generating capacity in 2023 will be solar (February 6, 2023), available at; https://www.eia.gov/todayinenergy/detail.php?id=55419

[119] Lower battery costs, high value of backup power drive distributed storage deployment. (n.d.). National Renewable Energy Laboratory (NREL) NREL. https://www.nrel.gov/news/program/2021/lower-battery-costs-high-value-of-backup-power-the-key-drivers-of-distributed-storage-deployment.html

Federal Energy Regulatory Commission Order 2222 enables DERs to participate alongside traditional energy resources in regional organized wholesale markets.[120] All of these factors contribute to the rise in DER deployment, including behind-the-meter battery storage. The number of customers that pair battery storage with distributed solar is rising as the cost of batteries declined over the past few years. According to NREL's modeling result, in all 2050 scenarios, there is notable economic potential for the combination of distributed battery storage with PV systems. Scenarios that consider conservative projections of battery cost reductions and attribute a lower value to backup power indicate an economic potential for 114 GW of storage capacity, marking a staggering 90-fold increase from current levels. That study also indicated that PV and batteries make an economical pairing.[121]

Energy storage systems can be pivotal in facilitating the clean energy transition, particularly when paired with renewables. By addressing the intermittent nature of renewable energy sources such as solar and wind, energy storage technologies like batteries enable the efficient capture and storage of excess energy generated during peak production periods. This stored energy can then be deployed during periods of low renewable energy generation or high demand, ensuring a consistent and reliable power supply. The synergy between energy storage and renewables not only enhances the overall reliability of the grid but also contributes to the reduction of greenhouse gas emissions by promoting a smoother integration of clean energy sources into the existing energy infrastructure. As Illinois moves towards a more sustainable and clean future, the strategic coupling of energy storage with renewables will be a key driver in creating a resilient, reliable, and low-carbon energy landscape.

Integrating energy storage systems with renewables yields several benefits crucial for the evolution of a sustainable, clean, and reliable grid. Firstly, storage optimizes grid operations by balancing electricity loads by storing excess energy during periods of high generation and releasing this stored energy during peak demand. As mentioned above, this load-balancing capability mitigates intermittency challenges associated with renewables and enhances grid stability. Storage helps firm up generation from intermittent sources by ensuring a continuous and reliable power output. Storage allows seamless energy supply continuity by avoiding outages. Storage facilitates arbitrage by capturing low-cost energy during off-peak hours and releasing it during periods of higher electricity prices, maximizing economic efficiency.

Lastly, as non-wire alternatives ("NWA"), storage solutions offer decentralized and flexible options for addressing grid constraints, reducing the need for extensive and costly infrastructure upgrades. The combination of storage and renewables stands as a multifaceted strategy, unlocking a spectrum of benefits critical for a clean, sustainable, and resilient energy future.

[120] FERC order No. 2222: Fact sheet. (n.d.). Federal Energy Regulatory Commission. https://ferc.gov/media/ferc-order-no-2222-fact-sheet.
[121] Lower battery costs, high value of backup power drive distributed storage deployment. (n.d.). National Renewable Energy Laboratory (NREL) NREL. https://www.nrel.gov/news/program/2021/lower-battery-costs-high-value-of-backup-power-the-key-drivers-of-distributed-storage-deployment.html.

i) Discussion of Energy Storage Reports and Analyses Produced Since CEJA's Passage

This section delves into the landscape of previous energy storage reports and analyses since the passage of CEJA in 2021. The ICC Energy Storage Program Report provides a more general background from the technological types of energy storage systems to the barriers that energy storage systems face from a national point of view.

By contrast, Sandia National Laboratories' report is a regional study that focus on Illinois MISO Zone 4 to addresses the challenges of integrating variable renewable energy and energy storage systems into power grids. It includes technical analysis that utilizes a mathematical framework to project potential capacity inadequacy by 2024 due to annual energy growth and increasing electric vehicle adoption, highlighting the role of energy storage in addressing generation gaps and supporting Illinois' decarbonization policies.

(1) Illinois Commerce Commission Energy Storage Program Report

The Illinois Commerce Commission's Energy Storage Program Report and the Sandia Nation Laboratories Energy Storage & Decarbonization Analysis for Energy Regulators – Illinois MISO Zone 4 Case Study report will be the focus of the discussion.

This Policy Study differs from the ICC report and Sandia's report in the following ways: this Policy Study begins with a comprehensive overview of the energy storage market and explores energy storage case studies from other U.S. states, such as New York, Massachusetts, New Jersey, and Maine to better inform legislators on the practices of other states pioneering in energy storage. Opportunities and barriers specific to Illinois are dissected, covering economic, reliability, and resilience benefits, along with challenges related to interconnection, financing, technology, and construction. This is done through both narrative analysis in this chapter and in other chapters, and through technical modeling conducted by the Agency's Procurement Planning Consultant and its subcontractors.

Mandated by Section 16-135 of the PUA, the ICC initiated a comprehensive examination of energy storage systems. This initiative identified programs, mechanisms, and policies conducive to energy storage deployment, aligning with the State's clean energy goals and fostering a competitive market.

The ICC's Energy Storage Program Report was released in May 2022 and underscores the multifaceted benefits and costs of energy storage systems, recognizing the imperative to overcome existing barriers.[122] The report outlines various energy storage types, emphasizing the advancements in battery technology, particularly the dominance of lithium-ion batteries in the market. While batteries offer valuable services to the grid, challenges persist in quantifying certain values and developing specific markets.

[122] Energy Storage Program. (n.d.). Illinois Commerce Commission. https://www.icc.illinois.gov/informal-processes/energy-storage-program.

Additionally, the report explicates the framework employed to assess the costs and benefits of energy storage systems, acknowledging the diverse benefits identified by experts. These include avoided costs, deferred investments, reduced ancillary services costs, lower peak power costs, and enhanced grid reliability, among others. Stakeholder input underscores the potential of energy storage to address challenges across different sectors.

To establish mid- and long-term storage deployment targets, the report advocates for generation expansion modeling and production cost modeling. It highlights the importance of clearly defining the focus of cost-benefit analysis, considering different perspectives and factors, particularly when evaluating storage as a service to utilities versus utility-owned storage.

The subsequent discussion centers on key policy issues and recommendations related to energy storage projects. Ten aspects, including procurement mandates, utility ownership, and changes to net metering, are examined. Stakeholders proposed recommendations such as a Flexibility Program[123] and a Power Quality Program[124] to drive energy storage deployment. The report emphasizes the need for a balanced approach, careful planning, and stakeholder engagement.

With respect to policy issues, the report identifies barriers hindering the realization of energy storage benefits, encompassing high initial costs, ongoing expenses, safety concerns, regulatory challenges, and uncertainty in benefits. It stresses the need for robust information before final decisions, recognizing the novelty and uncertainties associated with energy storage technology.

The conclusion highlights valuable insights from webinars and workshops, supported by Sandia National Labs and the U.S. Department of Energy ("DOE"), and can help form the foundation for an energy storage program in Illinois. The ICC proposes four recommendations in the report, including: refraining from specific deployment targets for utilities serving over 200,000 customers citing ongoing proceedings that may impact targets; allocating funds for a technical consultant to evaluate storage's future role, running models for utility-scale resource additions, and managing stakeholder input on state decarbonization; exploring energy storage pilot projects to gather additional information on costs and benefits; and considering new energy storage programs not possible under existing legislative authority and identifying legislative changes required for their implementation.

[123] A Bring-Your-Own-Device program that creates a simple and predictable opportunity for customer-owned devices, including energy storage, smart thermostats, electric vehicles, and other controllable load, to provide peak reduction, load shifting/ramp, renewable integration, and transmission deferral services to the energy system.

[124] An energy storage-specific program could be implemented with Commission approval to compensate customer-owned energy storage systems on select feeders for services provided to support local power quality, through the provision of VAR support and enabling greater hosting capacity by serving as a local active power sink to prevent backfeed.

In summary, the Energy Storage Program Report provides a comprehensive analysis of energy storage systems, delineating benefits, challenges, and policy considerations to inform strategic decisions for advancing Illinois' clean energy goals.

(2) Sandia National Laboratories Energy Storage and Decarbonization Analysis for Energy Regulators (Illinois MISO Zone 4 Case Study)

In October 2023, Sandia National Laboratories released a report examining the need for energy storage systems within Illinois MISO Zone 4 (the service territory of Ameren Illinois and overlapping rural electric cooperatives and municipal electric utilities). This report addresses the escalating global trend of jurisdictions implementing policies to combat climate change, resulting in increased integration of variable renewable energy ("VRE") and ESS into power grids.[125] The primary challenge lies in accurately determining the requisite amount of ESS to counter VRE variability and achieve decarbonization goals. The collaborative effort between Sandia and the ICC was conducted under the auspices of DOE's Office of Electricity Energy Storage Program. The technical analysis focuses on the transition from fossil-fueled generators to VREs in the Illinois MISO Zone 4 over the next two decades. The study explores various boundary conditions, including capacity and energy adequacy, to ascertain the minimum ESS quantity necessary. Multiple scenarios are examined, considering the impact of VRE capacity variations on system resource adequacy, as well as potential fossil-fueled asset retirements. The findings emphasize that, based on current plans for new additions and retirements of generating assets, a substantial deployment of ESS is imperative for meeting the electricity demand in Illinois MISO Zone 4 over the next two decades.

The analysis employs a mathematical framework that captures capacity adequacy, energy adequacy, and energy storage sizing methodologies essential for the region. Projections indicate that annual energy growth, coupled with incremental increases in electric vehicle ("EV") adoption and electrification, may lead to potential capacity inadequacy. The current capacity value of installed generating resources in Illinois MISO Zone 4 is anticipated to fall short of meeting annual peak demand as early as 2024.[126] The report further examines the repercussions of early coal plant retirements in MISO Zone 4, envisioning the cessation of operation of all coal plants by 2040. Replacement of closed coal plants by wind and solar plants is considered, with an assessment of the impacts on energy adequacy and system capacity. Recognizing the variable nature of these renewable assets, the report underscores the necessity for ESS to address the challenges posed by night and peak demand loads after sunset.

This report holds significance to the Policy Study by contributing valuable insights to support energy storage in Illinois. As variable renewable energy sources are integrated into the grid,

[125] Sandia Report SAND2023-10226 "Energy Storage & Decarbonization Analysis for Energy Regulators — Illinois MISO Zone 4 Case Study," (October 2023).

[126] Sandia Report SAND2023-10226 "Energy Storage & Decarbonization Analysis for Energy Regulators — Illinois MISO Zone 4 Case Study," (October 2023).

the potential for generation gaps underscores the crucial role of storage systems in addressing disparities. The study also considers the strategic retirement of fossil-fueled assets, a key aspect of broader Illinois decarbonization policies. Despite strong support for energy storage, future work should focus on optimizing the strategy and determining the ideal generation mix between storage and variable renewable energy. This nuanced analysis aims to refine our understanding and guide policy frameworks toward a more efficient and sustainable energy future.

ii) Energy Storage Policy Program Case Studies

Five states—New York, Massachusetts, New Jersey, Maine, and California—provide instructive case studies on how energy storage could be deployed. These five states discussed below were selected by the IPA to serve as reference points for Illinois in the design of its energy storage policies and programs. The selection criteria included the presence of a fully or partially restructured electricity market and progress in advancing storage project facilitation. These states are recognized here for their proactive approach to sustainable energy policies and have demonstrated a commitment to advancing energy storage development towards their storage target. Those criteria position these five states as valuable benchmarks for Illinois when shaping its own energy storage policies. Each state's unique policy initiatives, regulatory frameworks, and implementation strategies will be analyzed to provide Illinois with valuable insights into the potential and the challenges of energy storage deployment. These case studies offer meaningful insights on the evolving energy storage markets in other U.S. states, providing a foundation for informed policy recommendations and future energy storage development in Illinois.

(1) Energy Storage Targets by State Overview

As the U.S. transitions towards a more sustainable and resilient energy future, the role of energy storage becomes increasingly prominent. One of the defining aspects of energy storage development across the nation is the establishment of energy storage targets. To support the reliability of renewable resources and ensure grid stability, various states have set targets for energy storage capacity. Currently, ten states have implemented clear procurement targets for energy storage.[127] Recently, Michigan became the first state in the Midwest to establish an energy storage standard, with at least 2,500 MW of front of the meter ("FTM")[128] energy storage plans to be on the books before 2030.[129] New York, in particular, has set the bar high by aiming to deploy 6,000 MW of energy storage capacity by 2030.[130]

[127] Storage strategies: an overview of state energy storage policy. (2023, March 8). Morgan Lewis. https://www.morganlewis.com/pubs/2023/03/storage-strategies-an-overview-of-state-energy-storage-policy.

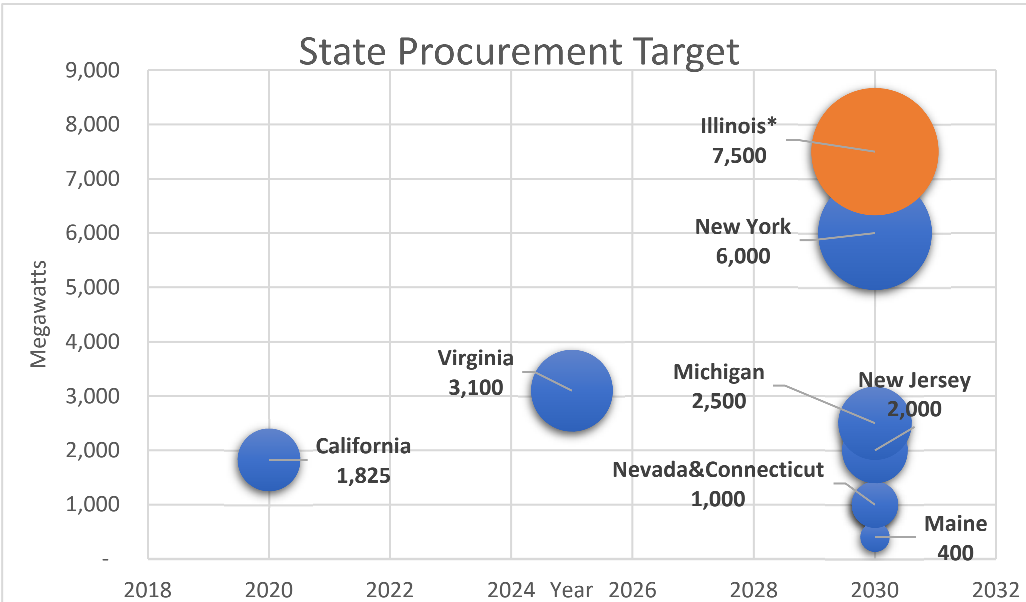
[128] Department of Environment, Great Lakes, and Energy. (2022, April 29). Storage seen as critical to Michigan's energy future. https://www.michigan.gov/egle/newsroom/mi-environment/2022/04/19/storage-seen-as-critical-to-michigans-energy-future.

[129] Sheri McWhirter. (Nov 24, 2023) Michigan first state in Midwest to set power storage benchmark. Available at: Michigan first state in Midwest to set power storage benchmark - mlive.com

[130] Energy Storage Program - NYSERDA. (n.d.). NYSERDA. Available at: https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program.

This ambitious goal reflects a commitment to harnessing the full potential of energy storage to enhance grid reliability and facilitate the integration of renewable energy sources. Figure 5-3 is a bubble chart that illustrates the energy storage targets of various states. The size of each bubble represents the size of the target, while the position on the X-axis indicates the year by which the state aims to achieve its target.

Figure 5-3: Energy Storage Target by State



*Note: Massachusetts is not on the graph because its target is set in MWh (not MW as displayed in the graph) at 10,000 MWh by 2025.[131] Similarly, Oregon is not on the graph as its target is Portland General Electric and PacifiCorp each to procure at least 5 MWh[132] by 2020.[133] Illinois' 7.5 GW target is not an actual target set by the state but rather a target number proposed in SB 1587.

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[131] Bill H.4857. (n.d.). The 193rd General Court of the Commonwealth of Massachusetts. https://malegislature.gov/Bills/190/H4857.

[132] The difference between MW and MWh is that MW measures power capacity, which is the maximum instantaneous amount of electric power that can be generated on a continuous basis and is measured in units of watts (kilowatts [kW], megawatts [MW], or gigawatts [GW]), while MWh measures energy capacity, which is the total amount of energy that can be stored in or discharged from the storage system and is measured in units of watthours (kilowatt-hours [kWh], megawatt hours [MWh], or gigawatt hours [GWh]), according to EIA. Different states use different measurement of capacity as their targets to meet their energy need.

[133] HB 2193 (2015), https://olis.oregonlegislature.gov/liz/2015R1/Downloads/MeasureDocument/HB2193.

Table 5-1: States with Carve-outs for Behind the Meter Energy Storage Capacity

California	Carve-out of 500 MW for Behind-the-meter (BTM)[134]
New York	Carve-out of 200 MW for BTM[135]
Connecticut	Carve-out of 580 MW for BTM[136]
Virginia	Carve-out of 310 MW for BTM[137]

In examining the landscape of energy storage initiatives across various states, a comprehensive overview of their respective targets provides a crucial foundation. The states listed above have ambitious goals, with designated target years and capacities for energy storage. But it is helpful to also look at the current stage of energy storage capacity within these states, particularly by the year 2023. By juxtaposing the envisioned targets with the real-time achievements, we can gain valuable insights into the progress made and the challenges faced in the energy storage development.

Figure 5-4 visualizes the current energy storage capacity (both operating and contracted) and the state targets by November 2023. Table 5-2 represents the detailed information on the year and capacity of the ten states.

[134] Bill text. (n.d.). California Legislative Information. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160AB2868.

[135] See New York's 6GW Energy Storage Roadmap (December 28, 2022), available at: Energy Storage Program - NYSERDA

[136] Colthorpe, A. (2021, August 12). Connecticut regulator creates program to incentivize 580MW of customer-sited energy storage. Energy-Storage News. Available at: https://www.energy-storage.news/connecticut-regulator-creates-programme-to-incentivise-580mw-of-customer-sited-energy-storage/.

[137] State Corporation Commission. (n.d.). HD13 (Published 2021) - Virginia energy storage task force: Final report (Chapter 863, 2020). Reports to the General Assembly - Published. https://rga.lis.virginia.gov/Published/2021/HD13.

Figure 5-4: Comparison Between Current Capacity and State Targets

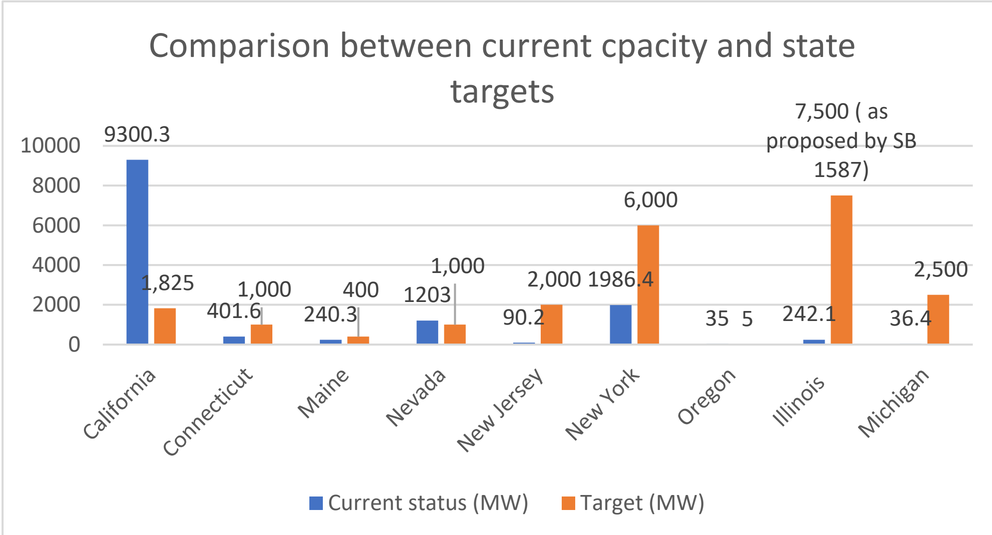

Table 5-2: Current Stage of Energy Storage Capacity

State	Operating/Online Capacity (MW)	Planned Capacity (MW)
California	7,343	1957.3
Connecticut	1.6	400
Maine	48	192.3
Massachusetts*	256.8	164.9
Nevada	265	938
New Jersey	70.2	20
New York	199.5	1786.9
Oregon	35	0
Illinois	50.1	192
Michigan	36.4	0

*Note: Massachusetts is not on the bar chart because its target is measured in MWh rather than MW.

Data source: EIA data[138]

(2) State-by-State Policy Design

(a) New York

New York State has outlined a comprehensive energy storage roadmap with the ambitious goal of achieving 6 GW of energy storage capacity by 2030.[139] This target is linked to the

[138] U.S. Energy Information Administration (EIA). (2023, December 21). Preliminary monthly electric generator inventory (based on form EIA-860M as a supplement to form EIA-860). https://www.eia.gov/electricity/data/eia860m/.

[139] See New York's 6GW Energy Storage Roadmap (December 28, 2022). Available at: Energy Storage Program - NYSERDA

State's broader commitment to the electrification of transportation and buildings, as stipulated in the Climate Leadership and Community Protection Act ("CLCPA"). The Climate Action Council Scoping Plan analysis underscores the necessity of expanding energy storage to 12 GW by 2040.[140] In 2030, a significant portion, constituting 66% of the 6 GW capacity, will be strategically located in downstate New York, specifically in zones J and K encompassing New York City and Long Island, under the jurisdiction of the New York Independent System Operator ("NYISO") based on the fact that downstate New York currently hosts a majority of emitting generators, and that integrating offshore wind is imperative for meeting stringent decarbonization requirements. Anticipating a substantial shift in focus from downstate to upstate New York between 2030 and 2050, this transition is attributed to the extensive electrification efforts and the deployment of large-scale renewables.

The first state-owned utility-scale battery energy storage project began operating at the end of 2023 in the North Country's Franklin County.[141] This Northern New York Energy Storage Project was built by the State in a rural northern region which generates over 80% of its electricity from clean energy sources. The facility functions under five enclosures, each housing over 19,500 batteries with capacity to distribute 4 MW and is equivalent to powering 3,000 households as shown in Figure 5-6. Figure 5-6 depicts one such enclosure beside a worker providing scalar reference.

Figure 5-5: Northern New York Energy Storage Project (Sky view)

[140] Scoping plan - New York's climate leadership & community protection act. (n.d.). NYSERDA. https://climate.ny.gov/resources/scoping-plan/

[141] T&D World, "New York's First State-Owned Utility-Scale Energy Storage System Now in Operation." August 2023. https://www.tdworld.com/electric-utility-operations/article/21272654/new-yorks-first-state-owned-utility-scale-energy-storage-system-now-in-operation.

Figure 5-6: Northern New York Energy Storage Project (Ground view)[142]

In New York, three categories of projects make up the program designs, namely bulk (utility-scale) projects, retail (commercial, industrial, community) projects, and single-family residential energy storage systems located in Long Island. The 6 GW roadmap prescribes the development of new programs catering to those three distinct sectors. As of now, a commendable 1.3 GW of storage capacity has already been awarded or contracted through this roadmap. To meet the 6 GW target, an additional 4.7 GW of new projects must be awarded by the year 2030.[143]

Table 5-3: New York State Energy Storage Targets by Sector

Sector	Capacity (MW)	Incentive mechanism
Bulk (>5MW)	3,000	Index Storage Credits + Upfront Rebate/Standard Offer Incentive
Retail (<=5MW)	1,000	Upfront incentive
Residential	200	Upfront incentive

This sector-specific capacity distribution is designed based on the current queue number and hosting capacity.[144] Additionally, the roadmap emphasizes a transition in the duration of storage from a 4-hour span in 2030 to an extended 8-hour duration by 2050. The initial 4-

[142] T&D World. (2023, August 29). *New York's first state-owned utility-scale energy storage system now in operation*. https://www.tdworld.com/electric-utility-operations/article/21272654/new-yorks-first-state-owned-utility-scale-energy-storage-system-now-in-operation

[143] NYSERDA. (2023, March 3). 6 GW Energy Storage Roadmap: Bulk Storage Overview Webinar – February 28, 2023. YouTube. Available at: https://www.youtube.com/watch?v=C2J60GLsus8&t=4912s.

[144] Hosting capacity - Hosting capacity is the amount of distributed energy resources that can be added to distribution system without causing problems or requiring upgrades.

hour duration is seen as representative of market signals, considering the diminishing value in energy arbitrage opportunities and the typically peaked capacity value within the 3–4-hour range. The progression to an 8-hour duration in the longer term is envisaged to serve peak demand or for replacement purposes, thereby addressing the need to replace existing generation sources and ensure reliability in the near term.[145]

The overall program funding comprises a total of $400 million in incentive funding, which is allocated through 2025.[146] The majority of this funding, specifically $350 million, is designated for investor-owned utility ("IOU") service territories. Bulk projects are designed for applications exceeding 5 MW in capacity, primarily targeting utility-scale installations. About $150 million in incentives is allocated for bulk projects within IOU service territories. Retail systems are designed for applications of up to 5 MW in capacity, catering to commercial, industrial, and community settings and will receive $130 million for retail incentives within IOU service territories. To incentivize the installation of single-family residential energy storage systems when integrated with solar PV installations in Long Island, an allocation of $53 million from the Regional Greenhouse Gas Initiative is dedicated to this purpose.[147]

NYSERDA offers several programs to support energy storage in New York state. The Energy Storage Program is a comprehensive program that provides incentives and technical resources for evaluating, developing, or installing energy storage technologies in New York.[148] The program aims to support a self-sustaining market for energy storage in New York by incentivizing approximately two-thirds of the State's 1,500 MW target of energy storage by 2025.[149]

There are several predominant procurement structures to support all three categories of energy storage in the state of New York.

- Bulk Storage Procurement Structure
    - Upfront Rebate/Standard Offer Incentive: Under this approach, support payments are provided in the form of a preset incentive, such as per kW or kWh of installed capacity, for which projects may apply once they have reached acceptable levels of project maturity, among other requirements.

[145] 6 GW Energy Storage Roadmap: Bulk Storage Overview Webinar. (February 23, 2023). NYSERDA, EB-2 National Interest Waiver - New Option 2023 for STEM Fields (youtube.com)

[146] Renewable Energy World. (2019, April 26). New York commits another $280M for energy storage. https://www.renewableenergyworld.com/storage/new-york-commits-another-280m-for-energy-storage/.

[147] Nyserda unveils $350/kWh retail energy storage incentive in implementation plan and program manual. (2019, March 15). Legal News & Business Law News | The National Law Review. https://www.natlawreview.com/article/nyserda-unveils-350kwh-retail-energy-storage-incentive-implementation-plan-and

[148] New York State Energy Research and Development Authority. (n.d.). Energy Storage Program. https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program.

[149] New York State Energy Research and Development Authority. (n.d.). Statewide Energy Storage Projects. Statewide Energy Storage Projects - NYSERDA.

Projects meeting funding criteria receive a contract for a fixed dollar amount that is paid out upfront or over a certain number of years.[150]

- Index Storage Credit ("ISC") Program: The program is designed to offer long-term certainty to projects, reduce financing costs, and maximize value for ratepayers. Modeled after the Index REC contracts for large-scale renewable generators in the state, the ISC program involves energy storage resources bidding a strike price in annual competitive solicitations, which is a key evaluation criterion for NYSERDA selecting projects. Selected projects would receive revenues that are estimated as the difference between the Strike Price and a Reference Price. If implemented, the proposed ISC mechanism will be the main incentive for the 3 GW of bulk storage resources to be procured by the State.[151]
  - Clean Peak Credit: Storage projects get compensation for discharging at pre-determined "peak hours." This program resembles the Massachusetts Clean Peak Standard that requires Load Serving Entities to serve an increasing proportion of load through zero-carbon resources during peak hours.[152]

- Retail Storage Procurement Structure
  - Market Acceleration Incentives Energy Storage Incentive Program: It provides region-specific, declining block incentives for energy storage systems of up to 5 MW. This approach successfully procured over 300 MW of projects, significantly expanding the project pipeline to over 1 GW, and is recommended to continue, aiming to procure an additional 1.5 GW of retail storage by 2030.[153]

- Residential Storage Procurement Structure
  - Within the first round of energy storage incentive programs in New York, funding for residential projects has been limited to projects paired with solar power and located on Long Island, due to Long Island's geography limits and grid infrastructure.[154] With a population of 7.5 million people on the island, Long Island's separation from the mainland imposes obvious constraints on delivering electricity. Furthermore, Long Island will serve as the receiving point for much of the offshore wind power, so capacity to store that power and send it to the mainland outside of transmission-constrained hours is valuable. Long Island, New York City, NYSERDA, and New York's Department of Public Service launched a statewide residential energy storage program with funding

[150] New York's 6GW Energy Storage Roadmap (December 28, 2022). Energy Storage Program - NYSERDA.

[151] Sustainable Energy Advantage, LLC. (July 6, 2023). New York's Index Storage Credits: Panacea or Pipedream? Available at: New York's Index Storage Credits: Panacea or Pipedream? | Sustainable Energy Advantage, LLC (seadvantage.com).

[152] New York's 6GW Energy Storage Roadmap (December 28, 2022). Available at: Energy Storage Program - NYSERDA.

[153] New York's 6GW Energy Storage Roadmap (December 28, 2022). Available at: Energy Storage Program - NYSERDA.

[154] Why Long Island could become New York's first energy storage hot spot. (2019, July 11). Greentech Media | Clean Tech & Renewable Energy News | Greentech Media. https://www.greentechmedia.com/articles/read/new-york-is-targeting-energy-storage-incentives-to-long-island.

for 200 MW available until 2030, and the program that emphasizes maximizing local benefits and benefits to Disadvantaged and Environmental Justice communities.[155] The incentive will be provided to the project installer upfront to directly drive down the cost of the project to the consumer.[156]

While New York has made significant strides in funding energy storage initiatives, including a major microgrid grant program, bridge funding incentives, and investments in long-duration energy storage technology development and deployment, challenges remain in terms of energy storage regulation and market adaptation. The policy and technological progress has outpaced regulatory frameworks, posing challenges for the effective deployment of energy storage and its integration into the New York's decarbonization goals.

(b) Massachusetts

Massachusetts' legislation *An Act to Advance Clean Energy* (House Bill 4857) sets an energy storage target of 1,000 MWh by 2025 for utilities.[157] The earlier interim target was 200 MWh by January 1, 2020. Governor Charlie Baker signed into law *An Act Driving Climate Policy Forward* that was designed to, among other things, encourage the development of mid- to long-duration energy storage facilities.[158] As of February 15, 2023, electric distribution companies reported 330 MWh of installed energy storage with an additional 2700 MWh of storage in the pipeline.[159] Massachusetts incentivizes energy storage development through several initiatives:

- Energy Storage Initiative: This initiative aims to make Massachusetts a national leader in the emerging energy storage market. It is a two-phase $10 million dollar initiative that has set a target of achieving 1,000 Megawatt hours of energy storage by December 31, 2025.[160] In the first phase of this initiative, the Massachusetts Clean Energy Center ("MassCEC") partnered with the State's Department of Energy Resources ("DOER") on an Energy Storage Study ("State of Charge" or the "Study") to obtain a broad view of energy storage technologies that will inform future policy and programs. In the next phase, energy storage demonstration projects were solicited through the Advancing Commonwealth Energy Storage ("ACES") Request for Proposals ("RFP"). The ACES program awarded grants totaling $20 million to directly

[155] Disadvantaged communities: those communities that bear burdens of negative public health effects, environmental pollution, impacts of climate change, and possess certain socioeconomic criteria, or comprise high-concentrations of low- and moderate-income households. New York enacts environmental justice permitting law. (2023, January 10). Beveridge & Diamond PC. https://www.bdlaw.com/publications/new-york-enacts-environmental-justice-permitting-law/.

[156] New York's 6GW Energy Storage Roadmap (December 28, 2022). Available at: Energy Storage Program - NYSERDA

[157] Bill H.4857. (n.d.). The 193rd General Court of the Commonwealth of Massachusetts. https://malegislature.gov/Bills/190/H4857

[158] Chapter 179. (n.d.). The 193rd General Court of the Commonwealth of Massachusetts. https://malegislature.gov/Laws/SessionLaws/Acts/2022/Chapter179

[159] Massachusetts Department of Energy Resources. (n.d.). ESI Goals & Storage Target. Available at: https://www.mass.gov/info-details/esi-goals-storage-target.

[160] Massachusetts Clean Energy Center. (2017). Advancing Commonwealth Energy Storage (ACES) Program Request for Proposals. https://www.masscec.com/sites/default/files/documents/Advancing%20Commonwealth%20Energy%20Storage%20%28ACES%29%20RFP%202017.pdf.

support 26 demonstration projects to cover up the project costs spanning nine use cases and 14 business models by 2017.[161]

- Solar Massachusetts Renewable Energy Target ("SMART"): This program includes incentives that encourage pairing energy storage with new solar installations. It includes a storage incentive adder within the solar rebate program. The SMART Program considered different incentive levels for a variety of installation types and established adders to Base Compensation Rates for certain facility types. DOER has created a calculator for prospective applicants to determine the potential value of an Energy Storage Adder, as well as a table and chart that illustrate potential adder values for Energy Storage Systems of different sizes. It is designed to incentivize the development of solar energy and promote the integration of energy storage technologies.[162]
- Connected Solutions: This is a utility-run incentive program spanning across Connecticut, Massachusetts, and Rhode Island that provides an annual incentive check when purchasing a battery and participating in the program. The program serves as a performance incentive for using storage as an efficiency measure. Customers receive payment for peak demand reduction. Utilities can enroll customers into the program through a 5-year, pay-for-performance contract that provides compensation in exchange for customer battery dispatch at peak demand hours. The customer responds to a utility signal for involvement.[163]
- Clean Peak Energy Standard: This is designed to provide incentives to clean energy technologies that can supply electricity or reduce demand during seasonal peak demand periods established by DOER.[164] The Clean Peak Standard creates credits for clean energy delivered during time windows identified as peak hours for a given season. Utilities in the State must obtain clean peak credits equal to a percentage of total electricity delivered in the year, starting at 1.5 in 2020 and growing annually. This creates an opportunity for energy storage technologies such as batteries, which store electricity for use when desired.[165]
- Utility Ownership: According to Sandia's report on Massachusetts Energy Storage Policy, even though Massachusetts is a deregulated state, utilities can install and own storage directly to simplify the process.[166]

[161] Clean Energy States Alliance. (2023, February 24). Advancing Energy Storage Technologies to Meet Clean Energy Goals in Massachusetts. Available at: https://www.cesa.org/advancing-energy-storage-technologies-to-meet-clean-energy-goals-in-massachusetts.

[162] Massachusetts Department of Energy Resources. (n.d.). Solar Massachusetts Renewable Target (SMART). Available at: https://www.mass.gov/solar-massachusetts-renewable-target-smart.

[163] Fields, S. (2020, May 22). The Connected Solutions Program: What You Need To Know. EnergySage. Available at: https://www.energysage.com/energy-storage/bring-your-own-battery-programs/the-connectedsolutions-program.

[164] Massachusetts Department of Energy Resources. (n.d.). Clean Peak Energy Standard Guidelines. Available at: https://www.mass.gov/info-details/clean-peak-energy-standard-guidelines.

[165] Spector, J. (2020, March 20). Massachusetts Set to Launch Clean Peak Standard, Opening New Chapter in Grid's Evolution. Greentech Media. Available at: https://www.greentechmedia.com/articles/read/massachusetts-clean-peak-standard-is-ready-to-go.

[166] Sandia National Laboratories. (2021). Massachusetts Energy Storage Policy. Available at: https://www.sandia.gov/app/uploads/sites/163/2021/09/GESDB_MassachusettsStorageSummary.pdf.

(c) New Jersey

New Jersey has 477 MW of existing energy storage, the majority of which is from one pumped hydroelectric storage facility as indicated in the *Draft 2019 New Jersey Energy Master Plan*.[167] The Plan also calls for developing 600 MW of energy storage by 2021, and 2000 MW by 2030.

In September 2022, the New Jersey Board of Public Utilities issued the New Jersey Energy Storage Incentive Program ("NJ SIP") Straw Proposal ("Straw").[168] The Straw outlines the creation of two distinct energy storage programs—one for Front-of-Meter and another for Behind-the-Meter energy storage incentives, both patterned after the solar-plus-storage program proposed in the Board's Competitive Solar Incentive ("CSI") Program. However, while the CSI Program was designed to incentivize solar-plus-storage projects, this Straw will focus on incentivizing stand-alone energy storage devices physically connected to a New Jersey electric distribution company ("EDC"). The proposal suggests that the incentives apply solely to energy storage projects commissioned after the effective date of the Board Order establishing this program.[169]

The incentive structure proposed in the NJ SIP states that:

- NJ SIP incentives will be available to energy storage devices that are located either in-front-of the-meter ("Grid Supply") or behind-the-meter ("Distributed" or "Customer Level"), and separate market segments will be created for both types of storage;
- A portion of the distributed storage incentive program will be reserved for projects located in, or directly serving, overburdened communities;
- Eligibility for NJ SIP incentives will be technology-neutral and based only on meeting functional requirements cost-effectively;
- The program would also provide fixed annual incentives ("Fixed Incentive") and include pay-for performance mechanisms ("Performance-based Incentives") for both market segments.

Fixed Incentives:

- At least 30% of the NJ SIP incentive will be structured as a fixed annual incentive, paid annually in dollars per kilowatt-hour ("$/kWh") of energy storage capacity contingent on satisfactory up-time performance metrics;
- The NJ SIP fixed incentive will be established through a declining block structure to establish a market-based incentive while also providing the industry with clear

[167] New Jersey Board of Public Utilities. (2019). Draft 2019 New Jersey Energy Master Plan [PDF file]. Available at: Draft 2019 EMP Final.pdf (nj.gov).

[168] New Jersey Board of Public Utilities. (n.d.). Notice in the matter of the New Jersey Energy Storage Incentive Program: Request for Information [PDF file]. Available at: Notice_RFI_NJEnergyStorageIncentiveProgram.pdf.

[169] New Jersey Board of Public Utilities. (n.d.). Energy Storage | NJ OCE Web Site [Web page]. Available at: Energy Storage | NJ OCE Web Site (njcleanenergy.com).

insights into the incentive value for energy storage devices. The Grid Supply and Distributed market segments will each have their own pricing structure.

The remaining NJ SIP incentive will be provided through a pay-for-performance mechanism:

- For Grid Supply storage resources, payment is based on the amount of carbon emissions abated through the operation of the energy storage device, determined by measuring the marginal carbon intensity of the wholesale electric grid (Marginal Emissions Rate set by PJM) at the time the energy is discharged, minus the carbon intensity of the energy drawn during the charging interval for the resource; and
- For Distributed storage resources, payment is based on the successful injection of power into the distribution system when called upon by the EDC during certain performance hours, established by each EDC.

To maximize private investment, the Proposal also suggested that in addition to the incentives discussed above, private investors be allowed to own and operate the energy storage devices, allowing them to "stack" revenues from the wholesale electricity market, to utilize the behind-the-meter resource to actively manage their energy usage at the distribution level and reduce electricity costs, or to participate in a Distributed Energy Resource ("DER") Aggregation service, when available.[170]

(d) Maine

Governor Mills signed Public Law 2021 Chapter 298 (L.D. 528 – An Act to Advance Energy Storage in Maine) in June 2021, which set goals for energy storage in the state of Maine and directed multiple important steps to advance its deployment to the benefit Maine.[171] Maine has established 300 MW by the end of 2025 and 400 MW by the end of 2030 goals for energy storage capacity installed within the State.

Additionally, L.D. 528 directs the Efficiency Maine Trust, an independent, quasi-state agency, to incorporate energy storage technologies into its electric efficiency and conservation program offerings.[172] The Efficiency Maine Trust will explore and evaluate options to expand existing opportunities and develop new opportunities to support energy storage measures that cost-effectively reduce or shift demand or balance load. The major projects that the Efficiency Maine Trust will carry on include:

- Expanding energy storage pilot projects within the Trust's innovation pilot program and implementing any cost-effective pilot projects as statewide programs. The Efficiency Maine Trust conducted a pilot program beginning January 1, 2022 to

[170] New Jersey Board of Public Utilities. (2021, July 28). PURA Establishes Statewide Electric Storage Program [Press release]. Available at: Notice_StakeholderMeetings_NewJerseyEnergyStorageProgram.pdf (nj.gov).

[171] 130th Maine Legislature. (2021). An Act To Advance Energy Storage in Maine (Legislative Document No. 528). Available at: https://legislature.maine.gov/bills/getPDF.asp?paper=SP0213&item=3&snum=130.

[172] Governor's Energy Office. (n.d.). Energy Storage. Available at: Energy Storage | Governor's Energy Office (maine.gov).

provide energy storage systems to critical care facilities, including but not limited to, hospitals, health care facilities, fire departments, emergency medical service departments, police departments, public safety buildings, emergency shelters and other facilities providing critical services. The total energy storage capacity deployed under the pilot program may not exceed 15 MW.

- Bring-your-own-device programs, in which customer-owned and customer-sited battery storage is aggregated and performance incentives are provided for reducing load at times of system peak. This pilot involves the installation of a fleet of between 50 to 100 dispatchable devices, including residential battery storage systems, to provide DERs that can be deployed to cost-effectively manage demand on the grid.
- Rebate or funding programs for energy storage paired with renewable energy for residential, commercial, and industrial electricity customers. Efficiency Maine's ESS Program Opportunity Notice offers performance-based incentives for the deployment of energy storage systems during summer peak demand conditions.
- Customer education initiatives regarding demand management and energy storage, including education targeted to low-income and rural populations in the State.

(e) California

California was the first state in the U.S. to deregulate its electricity market. Missteps in the State's deregulation process led to a major energy crisis in 2000, and its deregulation is largely on hold. As a result, California operates in a very different regulatory environment from Illinois.[173] Despite this difference, the focus on California in this policy study stems from its status as a leader in the United States' energy storage market. California houses a utility-scale energy storage project, The Moss Landing Energy Storage Facility, which began operating at the end of 2020 with a capacity of 300 MW and has since achieved a capacity of 400 MW— the country's largest battery storage project.[174] The Moss Landing Energy Storage Facility is located on the site of a retired gas-fired power plant on California's central coast, granting opportunity to repurpose the former turbine building to instead support battery placement (Figure 5-7).[175] The project area houses approximately 100 battery enclosures, each composed of battery cells, racking, container systems for power conversion, and step-up transformers for voltage output.[176] It is helpful to explore the designs of energy storage policies by studying California's energy storage programs.

[173] ElectricityPlans.com. (2023). Energy Deregulation by State, available at: https://electricityplans.com/energy-deregulation-state/.

[174] NS Energy, "Moss Landing Battery Storage Project." https://www.nsenergybusiness.com/projects/moss-landing/ .

[175] Pacific Gas and Electric Request Approval of Four Energy Storage Facilities with the Following Counterparties: mNOC, Dynegy, Hummingbird Energy Storage, LLC, and Tesla. Resolution E-4949, 2018. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M238/K048/238048767.PDF.

[176] Fu, R.; Remo, T.; Margolis, R. "2018 U.S. Utility-Scale Photovoltaics-Plus-Energy Storage System Costs Benchmark." National Renewable Energy Laboratory, October 2018. https://www.nrel.gov/docs/fy19osti/72401.pdf.

Figure 5-7: Moss Landing Energy Storage Facility[177]

For the last decade, California has been a frontrunner in both the development of storage technologies and the legislative and regulatory policies that are needed to enable the growth of a storage marketplace.[178] California's energy storage policy is a mix of executive directives, legislation, and regulatory decisions. The State's energy storage policy was formulated with three primary goals: Grid optimization, integration of renewable energy, and greenhouse gas ("GHG") reductions in support of the State's targets.[179] The Energy Storage Program is designed to facilitate California's aggressive Renewable Portfolio Standard (33% by 2020) and greenhouse gas reduction target (80 % below 1990 levels by 2050) by vastly increasing the State's energy storage capacity.[180] Key storage-focused legislation in California include AB 2514, enacted in 2010, which was the first state law in the U.S. establishing a mandate for energy storage systems. AB 2514 directed the California Public Utilities Commission ("CPUC") to require California's three investor-owned utilities to procure 1.3 GW of storage capacity by 2020, split among the transmission, distribution, and customer domains. The targeted goal of 1.3 GW of storage was intended to be split evenly among the three investor-owned utilities. The target is divided in sub targets related to storage at the transmission level, distribution level, and at the end-user level behind the meter. Targets are defined in

[177] The Moss Landing ESS Facility used here as an illustrative example of a large energy storage project was installed and operated by a subsidiary of Vistra. Vistra is the owner of several current and closed coal plants in Illinois that are potential locations for energy storage projects as discussed in Section 5.d.v.

[178] Sandia National Laboratories. (2021). California Energy Storage Policy Snapshot. Available at: https://www.sandia.gov/app/uploads/sites/163/2021/09/GESDB_CaliforniaStorageSummary.pdf

[179] California Public Utilities Commission. (2023). Energy Storage, available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/energy-storage

[180] Arizona State University. (2014, March). CA Energy Storage. Available at: https://sustainability-innovation.asu.edu/energy-policy/2014/03/caenergystorage/

power capacity (MW) without defining technology, ramp-up time, amount of energy (MWh), or duration. It is left to the market to determine what kind of energy storage is the most cost effective and adds the most value to the electricity system.

California further develops its energy storage initiatives through a variety of incentive programs. These comprehensive efforts collectively position California as a noteworthy case study for the strategic integration of energy storage solutions, providing valuable insights for Illinois navigating the evolving energy paradigm:

- Self-Generation Incentive Program ("SGIP"): SGIP is a CPUC program that offers rebates for installing energy storage technology on the customer's side of the utility meter. The incentive values decline over time as more battery installations occur throughout the State.[181] The rebate value also depends on the size of the battery installed. For most residential customers, SGIP is currently in Step 6, or $200 per kilowatt-hour of stored energy capacity.[182]
- Equity Resilience Incentives: As a part of the SGIP program, California offers an extra incentive for "Equity Resiliency" projects, including low-income households, customers living in high-risk fire areas, customers who experienced Public Safety Power Shutoffs events on two or more distinct occasions, and critical facilities that provide services to the affected areas. Eligible entities falling within these categories can avail themselves of an SGIP rebate ranging from $850 to $1,000 per kilowatt-hour.[183]
- Federal Investment Tax Credit ("ITC"): Most homeowners in California choose to pair an energy storage system with a solar battery. Homeowners opting for this dual solution can claim a substantial credit of up to 30% of the total cost of their solar battery as a credit towards their federal taxes.[184]
- Long-Duration Energy Storage program: The California Energy Commission approved a $30 million grant to Form Energy to build a long-duration energy storage project that will continuously discharge to the grid for an unprecedented 100 hours.[185]

(3) Summary of Five States' Energy Storage Policies

The policy designs of New York, Massachusetts, New Jersey, Maine, and California reflect diverse approaches to incentivize and regulate energy storage. If the IPA is tasked with

[181] EnergySage. (2023). 2023 California Storage Incentives, Tax Credits & Rebates. Available at: https://www.energysage.com/local-data/storage-rebates-incentives/ca/.

[182] California Public Utilities Commission. (2020). Self-Generation Incentive Program (SGIP). Available at: https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpucwebsite/content/news_room/newsupdates/2020/sgip-residential-web-120420.pdf.

[183] EnergySage. (2023). 2023 California Storage Incentives, Tax Credits & Rebates. Available at: https://www.energysage.com/local-data/storage-rebates-incentives/ca/.

[184] EnergySage. (2023). 2023 California Storage Incentives, Tax Credits & Rebates. Available at: https://www.energysage.com/local-data/storage-rebates-incentives/ca/.

[185] California Energy Commission. (2023). CEC Awards $30 Million to 100-Hour, Long-Duration Energy Storage Project. Available at: https://www.energy.ca.gov/news/2023-12/cec-awards-30-million-100-hour-long-duration-energy-storage-project.

developing energy storage procurement initiatives to achieve an ambitious 7.5 GW storage target by 2030 as outlined in SB 1587. Studying these five states equips Illinois with an understanding of regulatory frameworks, funding mechanisms, and technology integration, aiding the effective development and implementation of energy storage initiatives to meet Illinois' ambitious targets and contribute to the State's clean energy goals. This section will provide a summary of the five states' policy designs, particularly the incentive mechanism they use for different types of energy storage projects.

(a) Incentives for Residential and Behind-the-Meter Storage Projects

Each of the five states employ a mix of upfront incentives, performance-based mechanisms, and special considerations for specific categories like income-eligible households or critical facilities for behind-the-meter energy storage projects. These incentives aim to stimulate residential energy storage adoption, contributing to broader state goals of grid resilience, decarbonization, and renewable energy integration.

Table 5-4: Incentives for Residential and Behind-the-Meter Storage Projects

State	Incentive Mechanism	Specifics
New York	Upfront incentives	Allocated capacity of 200 MW with upfront incentives.
New Jersey	Fixed annual incentive + pay-for-performance mechanisms	At least 30% of the incentive will be structured as a fixed annual incentive through a declining block structure and the remaining will be pay-for-performance incentives.
Massachusetts	Pay-for-performance incentive	Performance incentive for demand peak reduction.
Maine	Pay-for-performance incentives	Performance-based incentives for residential energy storage paired with renewable energy, along with pilot programs for critical care facilities and bring-your-own-device initiatives.
California	Tax credits + pay-for-performance incentives	500 MW carved out for behind-the-meter storage. Up to $1,000/kWh for residential storage installations, and an additional equity resilience incentive for eligible projects, including low-income households and critical facilities + tax credit of up to 30 percent of the total cost.

(b) Incentives for Utility-Scale and Front-of-the-Meter Energy Storage Projects

Compared with behind-the-meter storage projects, some states use grants to directly fund those large-scale projects. New York is using an innovative indexed storage credit mechanism to incentivize its bulk storage projects.

Table 5-5: Incentives for Utility-Scale and Front-of-the-Meter Energy Storage Projects

State	Incentive Mechanism	Specifics
New York	Index Storage Credit + pay-for-performance incentives + grants	Selected projects receive revenues based on the difference between the Strike Price and a Reference Price + Compensates storage projects for discharging during pre-determined peak hours.
New Jersey	Fixed annual incentive + pay-for-performance incentives	At least 30% of the incentive will be structured as a fixed annual incentive through declining block structure and the remaining will be pay-for-performance incentives.
Massachusetts	Grants + Pay-for-performance incentive + Utility ownership	$20 million in grants supporting 26 projects + Utilities obtain clean peak credits for demand peak reduction.
Maine	Pay-for-performance incentives	Rebate or funding programs for energy storage paired with renewable energy for commercial, and industrial electricity customers.
California	Grants	$30 million grant to build a long-duration energy storage project.

c) Additional Opportunities and Barriers for Energy Storage

i) Opportunities

(1) Inflation Reduction Act ("IRA")

The federal Inflation Reduction Act ("IRA"), signed into law in August 2022, has created a favorable environment for energy storage initiatives across the country. This legislation offers a substantial economic boost specifically for large-scale battery projects. Under the provisions of the IRA, standalone storage systems are eligible for a thirty percent ITC.[186]

[186] Utility Dive. (2022, November 7). *IRA sets the stage for US energy storage to thrive.* https://www.utilitydive.com/spons/ira-sets-the-stage-for-us-energy-storage-to-thrive/635665/

Prior to the enactment of the IRA, energy storage developers could only benefit from federal tax credits when their storage projects were coupled with renewable generation. The IRA also ensures the longevity of these incentives, extending them through 2032, and eliminating the uncertainty associated with short-term incentives that are subject to renewal every one or two years. This extended timeframe provides storage developers and investors with a generous and stable window to capitalize on the potential returns offered by the Act.

The IRA presents an additional tax credit opportunity for standalone energy storage developers by advocating for certain labor requirements, similar to those available under CEJA in Illinois. Energy storage projects can maximize tax credits under the IRA if they pay prevailing wages set by the U.S. Department of Labor.[187] CEJA's equity components also focus on ensuring that a clean energy economy benefits all communities. Additionally, Illinois can incentivize the deployment of energy storage systems irrespective of project type by utilizing a combination of IRA and state incentives, similar to New York's storage program.

The reduction of costs through IRA incentives can enable stand-alone storage projects to become cost-competitive in the energy market.

(2) Opportunities for Storage in Illinois through CEJA

In addition to the Energy Storage Report developed by the ICC and described in Section 5.b.i, CEJA also created new incentives for pairing energy storage with solar systems to better integrate renewable energy and increase resiliency. New provisions contained in Section 16-107.6(c)(1) of the Public Utilities Act allows for a base rebate compensation for smart inverters associated with distributed generation. Customers who install photovoltaic facilities paired with energy storage on or adjacent to their premises also can receive a base rebate of $250 per kilowatt-hour of nameplate capacity compensation. If a distributed generation system has associated energy storage, then the energy storage system compensation may be separate from the base rebate.

These provisions allow individuals or entities that own or operate distributed generation systems to be eligible for net metering, and to request a base rebate for energy storage devices. The rebates are available for energy storage devices that use the same smart inverter as the distributed generation system, regardless of whether the distributed generation system itself applies for a rebate. This incentive established through CEJA presents an opportunity for those with distributed generation systems to receive financial incentives for integrating storage technology, promoting adoption of smart inverters, and enhancing the overall efficiency and reliability of renewable energy systems.

The incentives to pair storage with distributed generation systems (solar and wind) are available for both residential and commercial customers. CEJA also creates a significant

[187] IRA sets the stage for US energy storage to thrive. (2022, November 7). Utility Dive. https://www.utilitydive.com/spons/ira-sets-the-stage-for-us-energy-storage-to-thrive/635665/

opportunity for energy storage in Illinois, given the ability of storage to alleviate the variability inherent in wind and solar resources.

Further, battery storage systems that can supply energy during peak hours serve as a viable alternative to peaker plants that traditionally rely on fossil fuels. The conventional approach of grid operators calling upon peaker plants during periods of high demand not only incurs high costs but also contributes to elevated greenhouse gas emissions. Recognizing these environmental and economic challenges, states such as Massachusetts[188] and New York[189] are actively incentivizing utilities and grid operators to adopt storage programs as a compelling solution to curtail both peak costs and emissions. This proactive approach aligns with broader efforts to transition toward cleaner and more resilient energy systems. By providing a quick response to changes in power demand, energy storage can help to maintain the balance between supply and demand on the grid.[190]

Section 16-135(a)(1)(C) of the PUA highlights the diverse capabilities of storage systems in providing ancillary services that extend beyond conventional functions like frequency response, load following, and voltage support.[191] Renewables, such as solar, experience voltage variations due to weather conditions. Solar paired with storage allows frequency regulation often referred to as solar "firming." Storage smooths any gaps that arise between solar energy supply. Depending on the time of day or cloud cover, solar panels can have a gap in energy supply while demand is constant at different phases.

ii) Barriers

This section delves into a comprehensive exploration of the multifaceted barriers of energy storage that impede its integration into our energy infrastructure. The widespread adoption of energy storage is marked by barriers that extend across different dimensions. Interconnection barriers stand as a formidable challenge in both PJM and MISO areas, hindering the efficient flow of energy between storage systems and the broader grid. Financing barriers, including RPS budget limitations and relatively high capital costs for energy storage systems, pose a significant obstacle. Navigating the complex terrain of funding and investment required for large-scale energy storage projects will be crucial. Additionally, economic challenges and technology limitations demand innovative solutions, while construction barriers caused by supply chain delays can impede the timely implementation of storage facilities. This section explores these barriers, providing insights into the diverse challenges that must be navigated to unlock the full potential of energy storage solutions.

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[188] 2023 Commonwealth of Massachusetts "Clean Peak Energy Standard," available at https://www.mass.gov/clean-peak-energy-standard

[189] New York's 6GW Energy Storage Roadmap (December 28, 2022), available at: https://www.nyserda.ny.gov/All-Programs/Energy-Storage-Program

[190] Energy storage: A key enabler for renewable energy. (n.d.). NAE Website. https://www.nae.edu/19579/19582/21020/294933/294951/Energy-Storage-A-Key-Enabler-for-Renewable-Energy

[191] 220 ILCS 5/16-135(a)(1)(C)

(1) Interconnection Barriers

Interconnection queues witnessed a notable 40% increase in 2022 compared to the preceding year, revealing a substantial surge in projects awaiting approval for grid connection.[192] Data from the Lawrence Berkeley National Laboratory indicates that, nationally, over 10,000 projects are currently in the queue, comprising 680 GW of energy storage and 1,350 GW of generation. Notably, the industry grapples with a predominant concentration of planned wind, solar, and energy storage initiatives. This scenario is consistent within the territories overseen by PJM and MISO. The magnitude of these interconnection queues underscores the imperative for strategic planning and streamlined approval processes within the energy sector.

(a) PJM

PJM is currently managing an unprecedented surge in new generation resources requesting to connect to the PJM grid, exceeding 200 GW. As of August 2023, the interconnection queue in Illinois encompassed approximately 10 GW, comprised of standalone storage projects or a combination of renewables and storage.[193] Many projects awaiting approval align with the State's clean energy objectives, primarily focusing on renewables. The substantial backlog of projects prompted PJM to temporarily suspend the queue in February 2023. Subsequently, a refined interconnection approval process has been established by PJM to expedite and streamline the interconnection procedures.[194] This initiative reflects the RTO's commitment to addressing the challenges posed by the escalating demand for new-generation resources while ensuring an efficient and reliable grid.

(b) MISO

As of July 2023, 2 GW of stand-alone storage projects and an additional 4 GW of wind generation with storage have received interconnection approval and are awaiting construction in MISO's interconnection process.[195] Projects, on average, experience a two-year delay in reaching commercial operation, primarily due to permitting and supply chain challenges. Regional organizations are actively refining processes to accommodate a growing number of renewable and storage projects in the future.

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[192] Utility Dive's FERC interconnection rule may not speed process in much of US: experts, Aug 4, 2023, Available at https://www.utilitydive.com/news/ferc-interconnection-queue-reform-spp-miso-pjm-rto/689965/

[193] Lawrence Berkeley National Laboratory. (n.d.). Generation, Storage, and Hybrid Capacity. Energy Analysis and Environmental Impacts Division. Available at: https://emp.lbl.gov/generation-storage-and-hybrid-capacity

[194] PJM Interconnection. (June 30, 2023). New Interconnection Process Aims to Ensure Reliability, Enable State Policies. Inside Lines. Available at: https://insidelines.pjm.com/new-interconnection-process-aims-to-ensure-reliability-enable-state-policies/

[195] Howland, E. (September 14, 2023). Midcontinent MISO Interconnection Queue Faces Supply Chain Challenges Amid Transmission Expansion. Utility Dive. https://www.utilitydive.com/news/midcontinent-miso-interconnection-queue-supply-chain-transmission-expansion-mtep/693652/

(c) Interconnection Queue Delays

The existing backlog in interconnection poses considerable financial implications for prospective projects. The current interconnection procedures encounter challenges in accommodating a diverse range of generation projects including combinations such as wind plus storage or solar plus storage. A crucial improvement lies in enhancing the interconnection process to systematically consider resources seeking interconnection based on their type and size. Previous introductions of FERC Order Nos. 845 and 888 have positively impacted the evaluation process, and RTOs and independent system operators ("ISOs") are actively engaged in reforming interconnection processes. These efforts aim to facilitate the seamless integration of renewable and storage resources while mitigating cost escalation attributed to backlogs or inefficient interconnection procedures.

The consequences of insufficient transmission planning for the future generation resource mix are evident in the generator interconnection queues.[196] Prospective generators are often confronted with very high network upgrade costs, reaching hundreds of millions of dollars, to interconnect with the transmission system. This issue of high network upgrade costs, coupled with cost uncertainties within the generator interconnection queues, has given rise to bottlenecks and substantial delays.[197] In certain instances, these delays extend up to four years, hindering the commercial operation of numerous renewable energy projects. The imperative to address and rectify these challenges in transmission planning is underscored by the considerable impact on both costs and timelines within the generator interconnection process.

(2) Financing Barriers

(a) Energy Storage Capital Costs

Energy storage system costs remained high in 2023 after the increase in raw material and component prices increased in 2022 due to supply chain disruptions and inflation.[198] According to Bloomberg, the average cost of a four-hour duration turnkey energy storage system is above $300/kWh. The storage cost projections employed in long-term planning models encompass a broad spectrum of capital costs, spanning both present and anticipated future expenditures. The NREL 2023 utility-scale battery storage cost projections utilize literature-based normalized cost reductions. The projections foresee capital cost reductions of 16-49% by 2030 and 28-67% by 2050.[199] The overall capital cost for a 4-hour battery

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[196] Lieberman, J. (2021). How Transmission Planning & Cost Allocation Processes are Inhibiting Wind & Solar Development in SPP, MISO, & PJM. *American Council on Renewable Energy (ACORE) Report.*

[197] Tackling high costs and long delays for clean energy interconnection. (n.d.). Energy.gov. https://www.energy.gov/eere/i2x/articles/tackling-high-costs-and-long-delays-clean-energy-interconnection

[198] Top 10 energy storage trends in 2023. (2023, January 11). BloombergNEF. https://about.bnef.com/blog/top-10-energy-storage-trends-in-2023/

[199] Cole and Karmakar (2023). Cost Projections for Utility-Scale Battery Storage: 2023 update. National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy23osti/85332.pdf

system based on these projections includes low, mid, and high estimates. These range from \$245/kWh (low), \$326/kWh (mid), and \$403/kWh (high) in 2030 and \$159/kWh (low), \$226/kWh (mid), and \$348/kWh (high) in 2050.[200] These projections include assumed operations and maintenance costs, lifetimes, and round-trip efficiencies.[201]

Several variables may impact the future trajectory of costs, encompassing factors such as market demand, supply chain expansions or limitations, interactions with related sectors such as electric vehicles, and the dynamics of material costs and availability.

(b) RPS Budget Limitations

In the Agency's 2022 Long-Term Renewable Resources Procurement Plan, which is the framework for the IPA's programs and procurements related to renewable energy development, the Agency has highlighted a challenge in modeling future RPS budget impacts due to a variety of uncertainties.[202] For example, project energization delays create budget uncertainties for utility-scale energy projects, and this may be similar for storage projects should existing interconnection challenges continue. SB 1587's suggested procurement strategy for storage projects also uses a non-frontloaded structure. This does not completely eradicate uncertainty. For RECs procured from utility-scale projects, an indexed REC model is utilized. While providing revenue stability to project developers, this model creates RPS budget uncertainty due to unknown future energy prices impacting the resulting REC prices (with REC prices increasing when energy prices decline, and vice versa). With a statutory cap on RPS collections from ratepayers, there is a tension between that cap and the budget uncertainty created by the indexed REC model.

The indexed storage credit mechanism, proposed in SB 1587 to support utility-scale energy storage, is similar to the Indexed REC model used for utility-scale wind, solar, and hydropower procurements. Under SB 1587, an energy storage credit price would be based on the difference between the bidder's strike price and a daily market volatility index that is representative of revenues available to the project through wholesale market arbitrage—meaning that actual credit prices required to be paid cannot be safely predicted even after contract execution. As a result, final design of a procurement structure for utility-scale energy storage should include mechanisms to ensure funding certainty. The model proposed in SB 1587 to support storage when that storage is paired with solar distributed generation would be based on a tariffed utility rate with cost recovery by the utility and thus would not appear to face the same budgeting challenges.

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[200] Cole and Karmakar (2023). Cost Projections for Utility-Scale Battery Storage: 2023 update. National Renewable Energy Laboratory. Available at: https://www.nrel.gov/docs/fy23osti/85332.pdf

[201] Round-trip efficiency: the ratio between the energy supplied to the storage system (measured in MWh) and the energy retrieved from it (also measured in MWh). This efficiency is expressed as a percentage (%). Clark, E. (2023, November 17). What is round trip efficiency? Energy Theory. https://energytheory.com/what-is-round-trip-efficiency/.

[202] 2022 Long-Term Renewable Resources Procurement Plan (n.d.). Illinois Power Agency. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/modified-2022-long-term-plan-upon-reopening-9-may-2022-final.pdf.

iii) Economic Challenges

(1) Calculating the Value of Energy Storage Using LCOEs, LCOS, and LACE

Stakeholders are impacted differently by large-scale energy storage projects, and this yields a difference in economic value interpretation. Project benefits depend on the choice of technology and the role of a stakeholder in the project. Many parties use the Levelized Cost of Energy ("LCOE")[203] and Levelized Cost of Storage ("LCOS")[204] to determine a project's value. LCOE measures the average present cost of electricity generation for a generating plant over the plant's lifetime. Often, generators use LCOE as the price required to achieve their Internal Rate of Revenue which is equal to the discount rate.[205] This metric applies to storage assets to measure the average price of electricity discharged over the lifetime of the energy storage asset. In contrast, LCOS captures the storage value of electricity rather than generation as it excludes the costs related to charging. A refined interpretation of LCOS, focusing on electricity storage rather than generation, excludes charging costs unrelated to cycle efficiency and other losses. Given the different interpretations of LCOS and LCOE, it is important to create a clear definition when developing storage and identify what it covers to capture the true economic value of storage to the grid.

While LCOE serves as a convenient summary measure for assessing the overall competitiveness of various generating technologies, it may not comprehensively encompass all the benefits that actual investments contribute to the grid. For full economic competitiveness between generation technologies, we need to also consider the value that the plant is providing to the grid. This value provides a proxy measure for potential revenues from the sale of electricity generated from a candidate project displacing (or the cost of avoiding) another marginal asset. The value can be captured through the levelized avoided cost of electricity ("LACE"). LACE sums up avoided cost over the financial life of a candidate project and converts to a stream of equal annual payments, which may then be divided by the average annual output of a resource. In contrast to LCOE, the evaluation of LACE necessitates tools capable of simulating the operational dynamics of a storage project within a specific region. Due to the complexity of simulation, most project value assessments commonly rely on LCOE and LCOS. Therefore, to accurately capture the genuine economic value of a storage project to the grid and ratepayers, it is imperative to calculate LCOE, LCOS, and LACE.

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[203] LCOE: measures the average present cost of electricity generation for a generating plant over the plant's lifetime.

[204] LCOS: as the average revenue per unit of electricity generated or discharged that would be required to recover the costs of building and operating a generating plant and a battery storage facility, respectively, during an assumed financial life and duty cycle.

[205] A discount rate is the rate of return used to discount future cash flows back to their present value. CFI Team. (2023, September 28). Discount rate. Corporate Finance Institute. https://corporatefinanceinstitute.com/resources/valuation/discount-rate/.

iv) Technology Limitations

(1) Safety

Safety is a substantial concern with lithium-ion battery technology in grid-scale storage. New York has experienced cases of battery fires on three separate projects. This happened between late May and late July 2023.[206] Fire incidents, occurring at a rate of three in two months, can impede any state's progress toward storage targets, presenting both optical and operational challenges for their clean grid initiatives. Therefore, to avoid fire safety concerns, grid-scale batteries require thermal stability and improved cycling.[207]

(2) Pollution

Besides safety concerns, energy storage systems (especially batteries) may be pollutive. Lithium-ion battery production is mineral-intense, posing a problem to Earth's limited mineral deposits and supply chain issues. It is estimated that Lithium-ion battery production consumes approximately 25% and 40% of all cobalt and lithium mining capacities respectively.[208] As batteries increasingly play a pivotal role in grid operations, the global extraction of resources like graphite, cobalt, lithium, copper, and rare-earth minerals is expected to undergo a 200% expansion in the future.[209] Mineral mining and lithium-ion battery ("LIB") production generate substantial carbon dioxide, while retired LIBs contribute to environmental threats with plastic waste and heavy metals in landfills or oceans. Recycling is crucial for a sustainable mineral supply chain and pollution reduction.

(3) Battery Storage System Degradation

Battery energy storage systems ("BESS"), especially those used in arbitrage (charge the system in the low-price hours and discharge in high price hours), face the threat of rapid asset degradation, as well as a higher capital expenditure volatility compared to thermal peaking plants and renewables.[210] Arbitrage strategies procure energy during periods of low prices, and subsequently sell during price increases. EIA reports that close to 80% of the battery capacity in the California Independent System Operator 60% of nationwide installed utility-scale storage systems were used for price arbitrage in 2021.[211] Battery energy

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[206] Spector, J. (2023, August 21). *New York is reeling from its hot battery summer*. Canary Media. https://www.canarymedia.com/articles/batteries/new-york-is-reeling-from-its-hot-battery-summer?utm_medium=email

[207] Huang, Y., & Li, J. (2022). Key Challenges for Grid-Scale Lithium-Ion Battery Energy Storage. *Advanced Energy Materials*, *12*(48), 2202197. https://doi.org/10.1002/aenm.202202197

[208] Huang, Y., & Li, J. (2022). Key Challenges for Grid-Scale Lithium-Ion Battery Energy Storage. *Advanced Energy Materials*, *12*(48), 2202197. https://doi.org/10.1002/aenm.202202197

[209] M. P. Mills, *2019. The "New Energy Economy": An Exercise in Magical Thinking*, The Manhattan Institute, New York, NY, USA 2019, https://www.manhattan-institute.org/green-energy-revolution-near-impossible

[210] Balaraman, K. (2023, July 18). *Battery storage systems could face rapid asset degradation, especially with arbitrage: Fitch*. Utility Dive. https://www.utilitydive.com/news/battery-storage-systems-rapid-asset-degradation-arbitrage-fitch-ratings/688275/

[211] Balaraman, K. (2023, July 18). *Battery storage systems could face rapid asset degradation, especially with arbitrage: Fitch*. Utility Dive. https://www.utilitydive.com/news/battery-storage-systems-rapid-asset-degradation-arbitrage-fitch-ratings/688275/ .

storage systems that could be developed in in Illinois are likely to engage in arbitrage. Degradation rates and BESS life expectancy will depend on factors such as battery chemistry, temperature, and style and frequency of operation. BESS can combine different revenue streams including capacity, arbitrage, and ancillary services under long-term offtake agreements. Hence, it is important to recognize the degradation of BESS when seeking to invest, develop, and bring more storage onto the Illinois grid.

Battery degradation can be managed through proper operations and maintenance to ensure that energy storage systems continue to provide benefits to the grid over time. SB 1587 proposes energy storage credit contract terms of at least 15 years, with deployment goals by 2030. Ensuring that the procured resources will continue to contribute to Illinois energy markets, grid reliability, and resilience will be the responsibility of the selected participants.

v) Construction Barriers

(1) Supply Chain Issues and Material Costs and Delays

Nationwide, project developers are witnessing the widespread impacts of supply chain limitations, exerting pressure on both the solar and storage industries. The supply chain for battery storage systems in the U.S. has been facing significant challenges, particularly in obtaining traditional electric utility system components, such as transformers and breakers. The U.S. heavily relies on importing the inputs for fabricated advanced battery packs from abroad. This exposes the U.S. to supply chain vulnerabilities that can disrupt the availability and impact the cost of these critical technologies.[212] The shortage of lithium, a crucial material for lithium-ion batteries, has caused a mismatch in supply and demand, leading to a surge in prices. In early 2022, spot prices for battery-grade lithium in China were $11,000/metric ton ("MT"). By February 2023, prices had surged to over $50,000/MT.[213] With the electric vehicle market booming, demand for batteries continues to soar despite limited supply. It takes about five years to establish a new lithium mine and approximately two years to set up a battery manufacturing plant.[214]

This supply chain squeeze is causing delays and price spikes amidst increasing demand. Developers for storage projects face uncertainties, making it difficult to obtain new projects and complete ongoing ones. According to Wood Mackenzie, the U.S. storage industry installed 2,145 MWh and 778 MW of storage in Q1 of 2023.[215] This represents a 26% decline from Q4 of 2022, largely due to supply chain delays that have affected the installation of grid-

[212] FACT SHEET: Biden-Harris administration 100-Day battery supply chain review. (n.d.). Energy.gov. https://www.energy.gov/articles/fact-sheet-biden-harris-administration-100-day-battery-supply-chain-review.

[213] Balaraman, K. (2022, March 31). *Supply-chain squeeze: Solar, storage industries grapple with delays, price spikes as demand continues to grow*. Utility Dive. https://www.utilitydive.com/news/solar-storage-delays-price-supply-chain/620537/

[214] Balaraman, K. (2022, March 31). *Supply-chain squeeze: Solar, storage industries grapple with delays, price spikes as demand continues to grow*. Utility Dive. https://www.utilitydive.com/news/solar-storage-delays-price-supply-chain/620537/

[215] Adapted from Colthorpe, A. (2023, June 15). *Supply chain, interconnection queues result in slow Q1 for US energy storage industry*. Energy-Storage.News. https://www.energy-storage.news/supply-chain-interconnection-queues-result-in-slow-q1-for-us-energy-storage-industry/

scale energy storage systems. The significant decline in the quarterly market growth can be attributed to two major factors: supply chain issues and interconnection queue backlogs. Addressing these issues is crucial to ensure sustained market growth.

In September 2023, lithium and battery storage system prices became manageable as supply chain issues cooled down.[216] However, the lead times for transformers and other equipment necessary for installing a battery energy system have greatly increased. For the past few years, raw material costs have remained volatile, and the dominance of electric vehicles is squeezing the stationary battery energy storage system industry. To identify and develop a means to solve supply chain-related issues, DOE conducted an assessment of the energy sector industrial base. The assessment identified four key areas that leave the energy supply chain vulnerable.[217] These include reliance on other nations for raw materials, components, and products; lack of developed supply chains for nascent technologies; having broad application requirements for lithium-ion batteries; and lack of standardization for energy storage applications. DOE acknowledges the pivotal role of a secure and resilient supply chain in achieving clean energy goals and leveraging the economic opportunities inherent in the energy sector's transition.[218] Therefore, DOE identified strategic opportunities to address the energy supply chain challenges, which include expanding domestic manufacturing capabilities; investing in and supporting the formation of diverse, reliable, and socially responsible foreign supply chains; and enhancing supply chain knowledge and decision-making. This may become a solution for reducing lead times for materials needed for developing energy storage systems and related supply chain issues.

A secure, resilient supply chain will be critical in harnessing emissions outcomes and capturing the economic opportunity inherent in the energy sector transition toward clean energy.

d) Proposed Energy Storage Procurement

i) Energy Storage Credits

SB 1587 proposes that for all procurements of energy storage credits, the Agency would procure indexed storage credits. Direct respondents would offer a strike price and the purchase price of the indexed energy storage credit payments would be calculated for each day. Each energy storage credit payment would be equal to the difference resulting from subtracting from the energy storage strike price, the sum of the daily energy volatility

[216] Adapted from Colthorpe, A. (2023, June 15). *Supply chain, interconnection queues result in slow Q1 for US energy storage industry*. Energy-Storage.News. https://www.energy-storage.news/supply-chain-interconnection-queues-result-in-slow-q1-for-us-energy-storage-industry/

[217] U.S Department of Energy. (2022). Grid Energy Storage: Supply chain deep dive assessment. U.S. Department of Energy Response to Executive Order 14017, "America's Supply Chains". https://www.energy.gov/sites/default/files/2022-

[218] U Grid energy storage: Supply chain deep dive assessment (Technical report). (2022, February 24). OSTI.GOV | U.S. Department of Energy Office of Scientific and Technical Information. https://www.osti.gov/biblio/1871557.

index,[219] and the reference capacity price for that day. If the difference is a positive number, the electric utility would owe the seller the amount multiplied by the number of indexed storage credits produced on a relevant day. If this difference results in a negative number, the settlement would be zero.

Contrasting indexed storage credits to RECs, RECs are designed to offer long-term financial certainty to projects, reduce financing costs, and maximize value for ratepayers. In the REC structure, generators receive compensation for generating and delivering power to the grid. However, indexed storage credits require compensation to be made in MWh because storage provides energy at needed hours. It is important to implement mechanisms that incentivize storage discharge at times of greatest need rather than discharging as much as possible. This underscores a key rationale for pairing storage with renewables— to provide energy during intermittent times.

For example, New York uses an index storage credit model for bulk storage (the primary focus is on 4-hour and 8-hour duration technologies). Operational storage projects are credited and compensated Index Storage Credits ("ISCs") equal to the MWh of storage discharge capacity of the unit. The ISCs are awarded only for the day on which a storage project is operational and available for dispatch. This makes the ISC structure lose the performance-based element encouraged under the Index RECs structure. ISC contracts have no performance, discharge, operation, and throughput requirements.

Furthermore, Index Storage Credits payments under NYSERDA are calculated as the strike price minus the reference price. The reference price is designed based on a set of indices or an index to approximate the amount of market revenue available to a typical project. Therefore, projects would be susceptible to price signals from commodity markets. Projects benefitting from the energy storage credit pricing mechanism are exposed to price signals from the energy market and must discharge when it makes sense given the market prices.[220] Failure to discharge when market prices dictate may result in the inability to generate market revenue. In the absence of market revenue, the payment for ISCs alone would not be anticipated to render projects economically viable.

Both ISCs from NYSERDA, and storage credits proposed in SB 1587, recommend contracts of at least 15 years for the specified amount of energy storage systems. The duration of storage credit payments to support projects impacts overall costs and effectiveness to hedge for revenue.[221] NYSERDA developed the program under 15-year contract terms after looking

[219] Daily energy volatility index" means a calculation, for a contracted energy storage system, of the difference in average price per megawatt-hour between the average of the "X" highest-priced hours and the "X" lowest-priced hours for each day in the day-ahead energy market of the energy storage duration of the contracted energy storage system for each day in the day-ahead energy market of the applicable pricing node of the independent system operator or regional transmission organization, where "X" equals the energy storage duration of the contracted energy storage system.

[220] New York's 6GW Energy Storage Roadmap (December 28, 2022). Available at: [Energy Storage Program - NYSERDA](), Page 49

[221]New York energy storage policy. (n.d.). Sandia National Laboratories. https://www.sandia.gov/app/uploads/sites/163/2021/09/GESDB_NewYorkStorageSummary_v2.pdf

into previous program data.[222] Contracts that are too short have additional risks in the later years of operational life that are not covered in the contracted revenue mechanism.

One other comparison between NYSERDA's energy storage programs and the program proposed in SB 1587 is the cost recovery mechanism for electric utilities. In New York, utilities amortize and recover the contract costs over the term of the contract and costs are recovered from all delivery customers.[223] SB 1587 proposes that utilities recover costs associated with the procurement of energy storage credits by assessing an automatic adjustment clause tariff across all retail customers in a uniform cents per kilowatt-hour charge. Additionally, while NYSERDA's Bulk Storage Incentive Program provides financial support for new energy storage systems that provide wholesale market energy, ancillary services, and/or capacity services, NYSERDA's competitive solicitations also include conducting competitive solicitations to deploy new long-duration and multi-day energy storage as proposed in SB 1587.

Finally, though NYSERDA's residential energy storage program emphasizes maximizing local benefits and benefits to Disadvantaged and Environmental Justice communities, NYSERDA's energy storage program contracts do not contain minimum equity standards or geographic requirements as proposed in SB 1587.

ii) Virtual Power Plant, Peak Remediation, and Large Distributed Generation Programs

SB 1587 proposes the study of a Virtual Power Plant Program where behind-the-meter systems may receive dispatch signals to manage load through aggregation. Aggregation allows pairing with eligible devices to reach the required minimum capacity. Aggregators must enroll retail customers and have a combined capacity of 100 kilowatts or more. Aggregators will also facilitate the dispatch of eligible systems and receive compensation from utilities.

Besides the Virtual Power Plant program, SB 1587 proposes the study of a Large Distributed Generation Program to enable participating customers to collectively deploy 100 kilowatts or more of eligible devices. The Large Distributed Generation Program aims to encourage pairing distributed renewable energy projects with one or more energy storage systems. This spills over to the Peak Remediation Program which tries to establish or encourage renewable energy dispatch during peak demand. However, the Peak Remediation Program has a maximum capacity. The Peak Remediation Program allows eligible devices with a nameplate capacity of at least 100 kilowatts but no more than 5 MW. The Peak Remediation Program also requires the deployment of devices to occur at a specified peak demand time, which includes from 4-8p.m. during the months of June, July, August, and September.

[222] New York's 6GW Energy Storage Roadmap, (December 28, 2022). Page 52. Available at: [Energy Storage Program - NYSERDA]

[223] New York energy storage policy. (n.d.). Sandia National Laboratories. https://www.sandia.gov/app/uploads/sites/163/2021/09/GESDB_NewYorkStorageSummary_v2.pdf.

The Virtual Power Plant Program closely resembles the Solar Plus Storage Initiative available to residential and commercial customers in Long Island, New York through the NY-Sun Incentive Program and Dynamic Load Management. Objectives for Dynamic Load Management include peak load shaving for Long Island residential customers. Eligible storage projects receive an upfront incentive of $250 kWh[224] per installed energy storage capacity (AC) and low-to-moderate residential customers can receive an additional $150/kWh. The initial budget for Long Island projects was $55 million.[225]

While both the Large Distributed Generation Program and Peak Remediation Program proposals from SB 1587 aim to encourage pairing renewable projects with storage (for discharge during peak times), the proposals differ from New York's programs through eligibility criteria. Long Island's Solar Plus Storage Program aims to encourage incorporation of only new Solar Plus storage and does not apply to already interconnected PV projects and standalone residential storage. Proposals in SB 1587 do not disqualify already interconnected PV paired with storage or residential storage not paired with PV.

Differences also arise in the maximum eligible capacity of an energy storage system. While SB 1587 proposes a nameplate capacity of at least 100 kilowatts and not more than 5 MW in the peak remediation program, the maximum eligible capacity energy storage system in New York is 25 kWh for residential storage and 15 MWh for commercial storage.[226] New York's program prevents inappropriate oversizing of energy storage capacity through the system's associated inverter because capacity (kWh AC) eligible for the incentive is limited to four times the rating (kW AC) of the inverter (i.e., a 4-hour battery). For example, if an inverter of 5 kW is needed for the function of the storage, incentives will be limited to 20 kWh (AC) of storage capacity.

SB 1587 proposes large distributed renewable projects paired with storage systems of up to 5MW, which resembles New York's Retail Energy Storage Incentive Program. New York's program accepts projects connected either directly to the distribution system or with a load behind the meter. The program design has helped New York procure over 300 MW of projects and an estimated project pipeline of about 1.5 GW of projects.[227]

New York's Dynamic Load Management Program also allows aggregation and targets to reduce peak demand. Participants receive compensation for reducing electricity drawn from

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[224] EC&M. (2019, July 19). *N.Y. Commits $55 million to Long Island energy storage*. https://www.ecmweb.com/renewables/article/20904757/ny-commits-55-million-to-long-island-energy-storage

[225]Solar Plus Energy Storage. (n.d.). NYSERDA - New York State Energy Research & Development Authority - NYSERDA. https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/2019-07-11-li-incentive-overview-program.pdf

[226]Solar Plus Energy Storage. (n.d.). NYSERDA - New York State Energy Research & Development Authority - NYSERDA. https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/2019-07-11-li-incentive-overview-program.pdf

[227] New York's 6GW Energy Storage Roadmap. (December 28, 2022). Available at:

https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/ny-6-gw-energy-storage-roadmap.pdf the grid on hot summer days. Pairing renewable projects, such as solar with storage, allows system charging during excess generation and discharge during peak times.

While there are nuanced differences, the structure and design of peak remediation programs share similarities with initiatives in Massachusetts and New York. These programs are fundamentally geared toward reducing emissions, integrating renewables, and bolstering grid resilience during peak hours. New York has defined its geographical focus, centering on New York City and Long Island, motivated by the presence of aging fossil resources in these regions. Significantly, akin to the Peak Remediation Program, New Yor''s Clean Peak Credit initiative compensates projects for discharging during specified peak hours.[228] In Massachusetts, the Clean Peak Standard mandates that utilities procure storage as a percentage of peak power, with noncompliance resulting in an alternative compliance payment. This underscores the State's commitment to achieving specific storage targets during peak hours. The Clean Peak Standard strategically incorporates storage as an integrative solution for renewable energy, facilitating the provision of power from renewables during intermittent periods.[229] SB 1587 accentuates the importance of peak remediation programs by delineating designated hours and advocating for synergies with renewable projects and aggregators, particularly those with a project size between 100 kilowatts and 5,000 kilowatts.

iii) Large Distributed Energy Resources Dynamic Load Program

SB 1587's proposed Large Distributed Energy Resources Dynamic Load Program seeks to evaluate customer aggregation and deployment of systems with loads of 100 kilowatts or more. These include aggregators, community renewable generation projects, distributed energy resources management systems, distributed renewable energy generation devices, eligible devices, and energy storage systems. The distributed level energy storage programs seek to add both commercial and residential programs with customer-sited batteries to provide grid benefits and cost-savings to ratepayers.

The Large Distributed Energy Resources Dynamic Load Program describes projects that resemble those in New York's Retail Storage Incentive Program, which seeks to procure distribution-connected projects. The major difference between the programs is that New York's retail storage incentive is a declining block structure and is unique depending on the region. Some of the blocks in New York include Long Island, Westchester, New York City, and the rest of the State. The category has managed to procure 320 MW of storage projects and

[228] Sustainable Energy Advantage, LLC. (July 6, 2023). New York's Index Storage Credits: Panacea or Pipedream? Available at: New York's Index Storage Credits: Panacea or Pipedream? | Sustainable Energy Advantage, LLC (seadvantage.com)

[229] Spector, J. (2020, March 20). Massachusetts Set to Launch Clean Peak Standard, Opening New Chapter in Grid's Evolution. Greentech Media. Available at: https://www.greentechmedia.com/articles/read/massachusetts-clean-peak-standard-is-ready-to-go

has a target of 1,500 MW of retail storage by 2030.[230] The overall cost for the 320 MW deployment across New York regions is $193 million.[231]

Unlike New York's retail program that has distributed-connected projects of up to 5MW in capacity, Illinois' Large Distributed Energy Resources Dynamic Load Program requires aggregating at least 100 kilowatts.[232] In New York, projects with a capacity size of over 5MW are classified as bulk storage and are eligible for a fixed, upfront incentive rate in dollars per kilowatt-hour of energy capacity, which decreases over time. The initial allocation for New York's bulk storage incentive program was 580 MW, but this was subsequently adjusted to 480 MW due to project cancellations. Twelve projects falling under the bulk storage category received $113 million in Market Acceleration funding,[233] with completion anticipated by the end of 2025.

iv) Long Duration or Multi-day Energy Storage Program

SB 1587 also proposes the study of long-duration or multi-day energy storage.[234] The proposal includes a firm energy resource procurement plan for new resources, including initiating proceedings and conducting competitive solicitations to deploy new long-duration[235] and multi-day[236] energy storage. SB 1587 proposes that the initial procurement would be a minimum of two new long-duration or multi-day energy storage resources each with a rated capacity greater than 20 megawatts.

Long-duration energy storage systems are designed to dispatch energy for periods of ten hours or more, whereas multi-day duration systems cater to dispatch needs exceeding 24 hours. In New York, the NYSERDA innovation program actively backs long-duration storage and has allocated a total funding of $33.6 million for this purpose. The first tranche of this funding saw five long-duration projects receiving a total of $16.6 million. Additionally, the initiative includes another tranche that involves a competitive solicitation process to procure storage, with a total allocation of $17 million. SB 1587's proposal does not mention whether the long-duration or multi-day storage procurements are competitive.

Even though different in market size than Illinois, California is actively involved in supporting long-duration storage projects. The California Energy Commission awarded $30 million in grants to support a 5 MW iron-air battery project set to be constructed in

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[230] New York's 6GW Energy Storage Roadmap (December 28, 2022). Available at: [Energy Storage Program - NYSERDA, page 14]

[231] New York's 6GW Energy Storage Roadmap, (December 28, 2022). Page 14

[232] https://ilga.gov/legislation/103/SB/PDF/10300SB1587sam001.pdf.

[233] The Market Acceleration Bridge Incentive Program: A part of the Energy Storage Program by the New York State Energy Research and Development Authority (NYSERDA)

[234] (20 ILCS 3855/1-94 new) Sec. 1-94.

[235] "Long-duration energy storage" means an energy storage system capable of dispatching energy at its full rated capacity for 10 or more hours.

[236] "Multi-day energy storage" means an energy storage system capable of dispatching energy at its full rated capacity for greater than 24 hours.

Mendocino County.[237] This storage project is the largest long-duration project in California and aims to discharge energy for an unprecedented duration of 100 hours. It is scheduled to begin operation by the end of 2025. Noteworthy among other long-duration project approvals is the $31 million allocated for a 60 MW renewable backup microgrid in San Diego County and $32 million allocated for a 20 MW microgrid project in Tehama County. These projects seem to indicate that long-duration storage projects can act like microgrids.

v) Coal to Solar and Energy Storage in Illinois

This Policy Study incorporates an examination of former coal plants or sites as potential venues for energy storage projects, in accordance with the directives outlined in P.A 103-0580. Former coal plant sites suitable for storage deployment are listed in Table 5-6. Many of these plants have either ceased operations or are slated for closure. Establishing storage facilities in these locales represents an opportunity for reinvestment in the respective communities. The strategic placement of energy storage systems could be advantageous as it leverages existing transmission infrastructure, thereby potentially mitigating the necessity for extensive infrastructure expenditures and repurposing utility infrastructure already present at these sites.

CEJA contained energy storage opportunities for Illinois that involve the conversion of coal plants or sites into energy storage facilities. The initiatives offered incentives to generators for installing energy storage facilities at former coal plant sites, contributing advantages to the electric grid, and enhancing the capacity for increased utilization of renewable resources. As a component of the clean energy transition, CEJA established both the Coal to Solar and Energy Storage Initiative and the accompanying Coal to Solar and Energy Storage Initiative Fund.

CEJA included a Coal-to-Solar Procurement conducted by the IPA in April 2022.[238] CEJA created subsection 1-75(c-5) of the Illinois Power Agency Act to support the development of "new renewable energy facilities installed at or adjacent to the sites of electric generating facilities that burn or burned coal as their primary fuel source." The provisions in the new subsection 1-75(c-5) also required the IPA to procure no more than 625,000 annual RECs for $30 per REC. The participating utility-scale solar projects had to be at least 20 MW but no more than 100 MW in size. Also, the storage facility size associated with the solar project was required to be at least 2 MW and no larger than 10 MW.

A total of six projects, all at the sites of coal facilities owned by Vistra Corp., were selected as these six projects met the requirements of the IPA Act. These projects include Baldwin Solar BESS LLC, Coffeen Solar BESS LLC, Duck Creek Solar BESS LLC, Hennepin Solar BESS LLC,

[237] CEC awards $30 million to 100-Hour, long-duration energy storage project. (n.d.). California Energy Commission. https://www.energy.ca.gov/news/2023-12/cec-awards-30-million-100-hour-long-duration-energy-storage-project.

[238] April 2022 Procurement of Renewable Energy Credits under the Coal-to-Solar and Energy Storage Initiative, (April 29, 2022). Illinois Power Agency. https://ipa-energyrfp.com/wp-content/uploads/2022/04/Public-Notice-of-Spring-2022-C2S-Procurement-Results-2022-4-29.pdf

Kincaid Solar LLC, and Newton Solar BESS LLC, each with a storage capacity facility of 2.24 MW (DC rating). However, in late 2023 Vistra indicated that three of these projects (the Kincaid Solar and BESS project, the Hennepin Solar and BESS project, and the Duck Creek Solar and BESS project) will not be constructed. The project developers cited economic infeasibility, attributing it to various factors, including but not limited to inflation, increases in the cost of capital, and challenges in the supply chain.

Also, the Coal-to-Solar provisions of CEJA created the Energy Storage Grant Program to incentivize firms to install energy storage facilities at former coal plants. The program administrated through DCEO identifies closed coal plants or those in the process of closing for participation. On June 1, 2022, Governor JB Pritzker and DCEO announced five recipients for grants from this initiative, with the first payments to be issued in 2025.[239] They include NRG Midwest Storage, LLC (NRG) in Lake County, NRG Midwest Storage LLC (NRG) in Will County, Dynegy Midwest Generation, LLC (Vistra) in Mason County, Electric Energy, Inc. (Vistra) in Massac County, and Illinois Power Resources Generating, LLC (Vistra) in Peoria County.[240] Following the criteria specified in Section 1-75(c-5), the five coal plant sites are set to receive a cumulative amount of $280.5 million over a ten-year duration, capped at $28.05 million annually. The initial disbursements are scheduled for 2025, aligning with the anticipated commercial operational status of the facilities. The funding allocated to each project is proportional to the megawatts (MW) of stored energy capacity implemented at the respective facilities.

[239] DCEO. (2022, June 1). *Press release*. Illinois Department of Commerce and Economic Opportunity. https://dceo.illinois.gov/news/press-release.24987.html

[240] Press release. (n.d.). Illinois Department of Commerce and Economic Opportunity. https://dceo.illinois.gov/news/press-release.24987.html

Table 5-6: Coal to Solar and Energy Storage Projects

Coal to Solar and Energy Storage Initiative				
Program/Procurement	**Project Name/Location**	**Status**	**Storage Size**	**Developer/Grantee**
IPA Procurement–- Coal to Solar	Baldwin Solar BESS LLC	Under Development	2.24 MWdc	Vistra Corp.
	Coffeen Solar BESS LLC	Under Development	2.24 MWdc	Vistra Corp.
	Duck Creek Solar BESS LLC	Terminated Contract	2.24 MWdc	Vistra Corp.
	Hennepin Solar BESS LLC	Terminated Contract	2.24 MWdc	Vistra Corp.
	Kincaid Solar LLC	Terminated Contract	2.24 MWdc	Vistra Corp.
	Newton Solar BESS LLC	Under Development	2.24 MWdc	Vistra Corp.
DCEO–- Coal to Solar Energy Grant	Waukegan Energy Storage Center	Under Development / Pending Grant Finalization	72 MW	NRG Midwest Storage, LLC (NRG)
	Will County Energy Storage Center	Under Development / Pending Grant Finalization	72 MW	NRG Midwest Storage, LLC (NRG)
	Havana Battery Energy Storage System	Under Development / Pending Grant Finalization	37 MW	Dynegy Midwest Generation, LLC (Vistra)
	Joppa Battery Energy Storage System	Under Development / Pending Grant Finalization	37 MW	Electric Energy, Inc. (Vistra)
	Edwards Battery Energy Storage System	Under Development / Pending Grant Finalization	37 MW	Illinois Power Resources Generating, LLC (Vistra)

Data source: Illinois Power Agency April 2022 Procurement of Renewable Energy Credits under the Coal-to-Solar and Energy Storage Initiative[241] and DCEO press release[242]

The table below shows a list of coal plant sites in Illinois that have either had retirements since 2016 or planned future retirements. The list includes operating sites with both operational units and closed units (for example Baldwin Energy Complex). The table also indicates whether the plants have previously participated in the coal-to-solar and storage initiative by the DCEO and IPA coal-to-solar procurements (including projects that terminated their contracts). N/A represents coal plants with no participation information or plans of hosting storage (N/A) and could be opportunities for the location of storage projects.

[241] April 2022 Procurement of Renewable Energy Credits under the Coal-to-Solar and Energy Storage Initiative, (April 29, 2022). Illinois Power Agency https://ipa-energyrfp.com/wp-content/uploads/2022/04/Public-Notice-of-Spring-2022-C2S-Procurement-Results-2022-4-29.pdf

[242] DCEO. (2022, June 1). *Press release*. Illinois Department of Commerce and Economic Opportunity. https://dceo.illinois.gov/news/press-release.24987.html

Table 5-7: Coal Plant Sites That Could Be Locations For Energy Storage Projects

Owner	Plant Name	County	RTO/ ISO	Capacity (MW)	Retirement Year	Status	Participating Program
Vistra	Kincaid Generation LLC	Christian	PJM	1112	2027	Operating	IPA Procurement*
NRG	Powerton	Tazewell	PJM	1785	2028	Operating	N/A
Vistra	Baldwin Energy Complex	Randolph	MISO	1156	2025	Operating (retired another unit in 2020)	IPA Procurement
City of Springfield	Dallman	Sangamon	MISO	230.1	2023	Out of service (retired 2 units in 2020)	N/A
Southern Illinois Power Co-op	Marion	Williamson	MISO	99		Operating (retired another unit in 2020)	N/A
Vistra	Newton	Jasper	MISO	617.4	2027	Operating (retired another unit in 2016)	IPA Procurement
Vistra	E D Edwards	Peoria	MISO	780	2022	Retired	DCEO Grant
Vistra	Joppa Steam	Massac	MISO	1100	2022	Retired	DCEO Grant
NRG	Waukegan	Lake	PJM	803	2022	Retired	DCEO Grant
NRG	Will County	Will	PJM	598.4	2022	Retired	DCEO Grant
Vistra	Duck Creek	Fulton	MISO	441	2019	Retired	IPA Procurement*
Vistra	Coffeen	Montgomery	MISO	888	2019	Retired	IPA Procurement
Vistra	Havana	Mason	MISO	488	2019	Retired	DCEO Grant
Vistra	Hennepin Power Station	Putnam	MISO	282	2019	Retired	IPA Procurement*
Vistra	Wood River	Madison	MISO	112.5	2016	Retired	N/A

Note: IPA Procurement* - Terminated IPA Coal-to-Solar Contract (discussed above)

Data Source: EIA Monthly Electric – November 2023 Generator Issue[243]

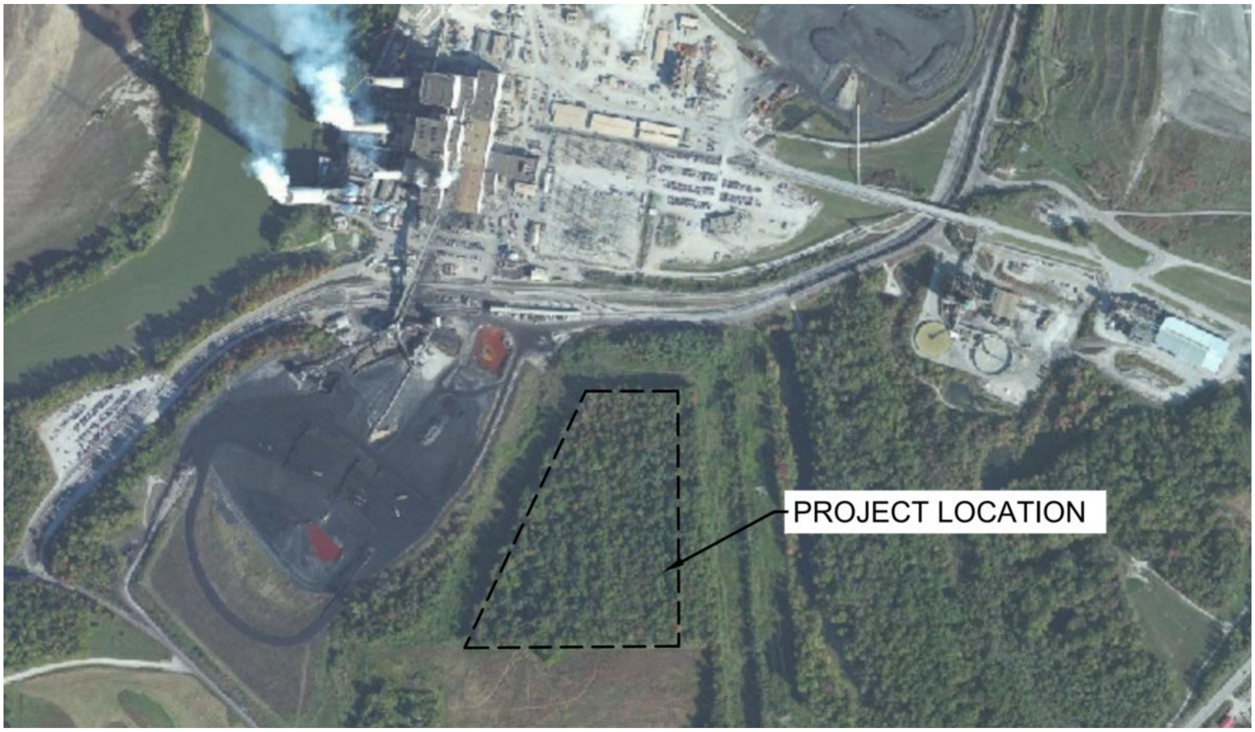
Former coal plant sites are increasingly being considered as potential locations for energy storage facilities.[244] Various states such as Indiana, New Jersey, and Massachusetts are actively exploring the transformation of former or retiring coal plant sites into energy storage facilities of different sizes. One significant example is the Pike County Energy Storage Project in Indiana (see Figure 5-8 below), designed to address the anticipated capacity shortfall in the winter of 2025, influenced in part by MISO's shift to seasonal capacity.[245]

[243] Preliminary monthly electric generator inventory (based on form EIA-860M as a supplement to form EIA-860). (n.d.). U.S. Energy Information Administration (EIA). https://www.eia.gov/electricity/data/eia860m/

[244] Former Coal Plant Sites Get Second Life With Energy Storage Systems, (September 11, 2023). American Public Power Association. [Former Coal Plant Sites Get Second Life With Energy Storage Systems | American Public Power Association]

[245] Howland, E. (2023, July 20). *AES Indiana plans 200-MW/800-MWh energy storage at retiring coal plant.* Utility Dive. https://www.utilitydive.com/news/aes-indiana-fluence-energy-storage-systems-petersburg-coal-plant/688478/

Figure 5-8: Pike County Energy Storage Project Location[246]



With approval to construct a 200 MW battery storage facility at a retiring coal plant, the project aligns with Indiana's Integrated Resource Plan and is expected to come online by December 1, 2024. The project anticipates eligibility for 40% federal tax credits as it falls within an "energy community" area.[247] Its impact on customer bills in Indiana, especially residential customers using 1,000 kWh or more, includes a modest increase of approximately 1% or $1.13 in the monthly bill.

e) Environmental Justice Impacts from Developing Energy Storage Projects

i) Utility-Scale Energy Storage Projects

Unlike the proposed offshore wind project and the SOO Green HVDC transmission line, proposals to develop energy storage projects in Illinois do not have specific locations identified, other than a high-level goal of 70% of utility-scale projects located in the MISO region of the State and 10% in Chicago.[248] This creates challenges for how to alleviate

[246] Weaver, J. F. (2023, July 26). *Replacing coal plant with largest energy storage project in Indiana*. pv magazine USA. https://pv-magazine-usa.com/2023/07/26/replacing-coal-plant-with-largest-energy-storage-project-in-indiana/

[247] Energy community is a community that has been historically sited near environmentally harmful industries like coal mining or oil extraction. https://www.democrats.senate.gov/imo/media/doc/inflation_reduction.

[248] One exception is the virtual power plant program described in SB 1587 provides that the Commission may provide compensation for third party aggregators deploying electricity to the grid to the extent that the aggregators' participating customers are located in equity investment eligible communities as defined by Section 1-10 of the IPA Act.

potential impacts on environmental justice communities from utility-scale energy storage facilities.[249]

For example, utility-scale energy storage facilities typically resemble a series of large shipping containers and feature associated electrical switching gear. These facilities will likely be in areas zoned for industrial or commercial use, not in residential communities. The potential energy storage sites modeled for transmission reliability and grid resilience range in size from 40 to 300 MW, which is illustrative of projects large enough to participate in an IPA procurement event for utility-scale energy storage. Small energy storage projects, such as Battery Energy Storage Systems, generally require one to two acres. For instance, a small project might consist of a cluster of battery banks (or modules) that are roughly the same size as a shipping container.[250] Large energy storage projects can require significantly more land. For example, the Manatee Energy Storage Center, which consists of 132 energy storage containers each holding roughly 400 battery modules, is spread across a 40-acre parcel of land.[251] Only the interconnection point, not exact location of the projects that were modeled for this Policy Study, is publicly available. The distance from that interconnection point to the actual proposed facility is not known, therefore it is difficult to assess the number of proposed energy storage projects in Illinois that would be in environmental justice communities.

The procurement for utility-scale energy storage projects outlined in SB 1587 includes requirements that winning bidders comply with the equity accountability standards outlined in Section 1-75(c-10) of the IPA Act (as well as the prevailing wage requirements contained in Section 1-75(c)(1)(Q)). One key aspect of the equity accountability system is the requirement that an increasing portion of the project workforce consist of equity eligible persons.[252] Qualifying as an equity eligible person requires the individual either to have graduated from or participated in a qualifying training program, to have graduated from or were enrolled in the foster care system, to have been formerly incarcerated, or to live in an Equity Investment Eligible Community.[253] The definition of Equity Investment Eligible Communities is broader than the definition of environmental justice communities as it also includes R3 communities, which are communities that have been "harmed by violence,

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[249] For a map of environmental justice communities in Illinois, as used in the IPA's Illinois Solar for All Program see: https://elevate.maps.arcgis.com/apps/webappviewer/index.html?id=d87a45c18a5c4e0fa96c1f03b6187267. This map is based a methodology contained in the Agency's Long-Term Renewable Resources Procurement Plan which calculates the top 25% of census tracts in Illinois based on a formula that utilizes eleven environmental and six demographic indicators and designates them as environmental justice communities. For more information, see Section 8.12 of the Long-Term Plan, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/modified-2022-long-term-plan-upon-reopening-9-may-2022-final.pdf. Note that this methodology differs slightly from that used by other State agencies in that it includes racial and ethnic demographics. This is due to the differing definitions of Environmental Justice Communities used in different Illinois statutes, but does not have a significant impact on the mapped areas.

[250] SolarLandLease, Should you lease your land for an energy storage project? (2021, August 19). https://www.solarlandlease.com/lease-land-for-an-energy-storage-project.

[251] Renewable Energy World. 10 notable battery storage projects that went live in 2021 (2022. January 11). https://www.renewableenergyworld.com/solar/10-notable-battery-storage-projects-that-went-live-in-2021/.

[252] The requirement is currently 10% and is required to grow to 30% by 2030. As part of that growth trajectory the Agency has proposed that the level will increase to 14% in 2025-2026 in the Long-Term Renewable Resources Procurement Plan currently under consideration by the Illinois Commerce Commission.

[253] For more information on Equity Eligible Person qualifications see: https://energyequity.illinois.gov/job-seekers.html.

excessive incarceration, and economic disinvestment."[254] This designation was developed as part of the cannabis legalization process in Illinois, and largely overlaps environmental justice communities. Requiring utility-scale energy storage projects to comply with minimum equity standards will help to facilitate employment opportunities for residents of environmental justice communities.

The Coal to Solar procurements conducted by the Agency in 2022 included a requirement that participating projects have a storage component including a provision that "the applicant commits that if selected, it will negotiate a project labor agreement for the construction of the new renewable energy facility and associated energy storage facility that includes provisions requiring the parties to the agreement to work together to establish diversity threshold requirements and to ensure best efforts to meet diversity targets, improve diversity at the applicable job site, create diverse apprenticeship opportunities, and create opportunities to employ former coal-fired power plant workers."[255] Similar provisions apply to the grants issued by DCEO under the Coal to Solar Energy Storage Grant Program.[256, 257] While SB 1587 would require project labor agreements, it does not contain similar provisions that those project labor agreements have diversity requirements, or commitments to hire displaced workers. Including these types of provisions could further connect utility-scale energy storage project development with workers from environmental justice communities.

ii) Distributed Storage

The proposals contained in SB 1587 to create opportunities for distributed storage (e.g., paired with solar projects for homes and businesses and with community solar projects) are not based on a competitive procurement model similar to what would be used for utility-scale storage projects. Instead, they are designed as a tariffed rate offered by a utility and managed through aggregators.

While there is no explicit discussion in the proposals of targeting specific communities, the storage would be paired with solar projects that would be participating in either Illinois Shines or Illinois Solar for All incentive projects. Projects participating in Illinois Shines are required to meet the same minimum equity standard as utility-scale projects, and through that standard, would similarly create employment opportunities for residents of environmental justice communities. The Illinois Solar for All Program (which focuses on supporting solar for income-eligible households and communities) has a different workforce requirement that is focused on utilizing graduates of job training programs. Illinois Solar for

254 See: https://r3.illinois.gov/ for more information on R3 communities, and https://energyequity.illinois.gov/resources/equity-investment-eligible-community-map.html for a map of Equity Investment Eligible Communities..

255 20 ILCS 3855/1-75(c-5)(1)(G).

256 20 ILCS 3855/1-75(c-5)(9)(C)(12).

257 "Pritzker Administration Announces Recipients of Coal-to-Solar Program as Part of Landmark Climate Initiative," June 1, 2022. https://dceo.illinois.gov/news/press-release.24987.html

All also features a goal of 25% of its funding allocated to projects located in environmental justice communities.

Distributed storage has an advantage over the other proposals considered in this Policy Study in that the sheer number of projects that would likely be supported is far greater, potentially thousands per year in the residential sector. This creates opportunities to tailor the proposal to provide targeted incentives to increase the number of projects located in environmental justice communities. This could be achieved through a higher tariff rate for projects in environmental justice communities, or potentially for those paired with projects participating in Illinois Solar for All.

One challenge that the Illinois Solar for All Program has faced in supporting solar for income-eligible residents is that many houses need roof and/or electrical upgrades before being suitable for solar installation. The program currently has a home repair pilot underway to explore reducing those barriers to participation.[258] Homes located in environmental justice communities are likely to face similar barriers for installing storage if the home's electric system needs substantial upgrades. Electric upgrades are upfront costs that are not well suited to be supported by a tariff, which would only provide benefits back to the customer once the storage system is installed and in operation. Identifying funding to assist homeowners with electric upgrades to make their homes suitable for installing storage systems could be essential for increasing adoption rates in environmental justice communities and income-eligible communities.

f) Modeling Results

As discussed in Chapter 4, the Agency conducted four different modeling exercises to assess the impacts of each policy proposal. The models used were:

- GE MARS to evaluate the impacts on generation reliability and resource adequacy (conducted by GE Energy Consulting)
- Siemens PTI PSS®E and PowerGEM TARA to evaluate the impacts on transmission reliability and grid resilience (conducted by ENTRUST Solutions Group)
- Aurora production cost simulation to evaluate the impacts on electricity prices and generation related emissions (Conducted by Levitan and Associates)
- IMPLAN to evaluate the impacts on the State's economy including job creation (Conducted by Levitan and Associates)

Full reports of each modeling exercise are available as Appendices B to E of this Study, and Chapter 8 provides an overview of the methodology used for each. This section breaks out the specific results for proposed levels of energy storage development. For generation reliability, resource adequacy, transmission reliability, and grid resilience, only utility-scale energy storage was modeled as distributed energy storage projects (e.g., paired with residential or commercial solar projects, or with community solar projects) are connected to

[258] See: https://www.illinoissfa.com/programs/residential-solar/.

the distribution system, not the transmission system and thus would not have transmission grid impacts. Because SB 1587 did not propose a level of deployment for distributed energy storage, a proxy 1,000 MW is used in the Aurora and IMPLAN modeling.

i) Generation Reliability and Resource Adequacy

Generation Reliability and Resource Adequacy are measured through two criteria, Loss of Load Expectation, and Effective Load Carrying Capability. Each were studied in 2030 and 2040 to evaluate impacts over time. The industry standard LOLE is 0.1 days/year (which can also be thought of as one day in ten years). This is the base case against which adding the proposed policy is studied to see if that level increases or decreases.

ELCC measures the resource's ability to produce electricity when the grid is most likely to experience an electricity shortage and is expressed as a percentage of a resource's total capacity. The value of this criteria is that it provides context for the significance of the contribution of the resource. For example, a resource may be 1,000 MW in size, but only 200 MW of that resource may have an impact on ensuring reliability. This discounting or derating could be due to factors such as when the resource is providing electricity to the grid.

The proposed 7,500 MW of utility-scale energy storage would have an impact on generation and resource adequacy. Against a base case of a 0.1 LOLE level, in 2030, LOLE would drop to 0.01, and in 2040, the LOLE would drop to 0. In other words, utility-scale energy storage could be expected to eliminate the likelihood of a loss of load event in 2040. In 2030, the proposed levels of energy storage would not yet be fully deployed, and thus the impact is not fully realized. Similarly, the ELCC for the deployment of utility-scale energy storage would be 94% in 2030 and 64% in 2040, indicating that a significant portion of the energy delivered by utility-scale energy storage systems would contribute to generation and resource adequacy.

Overall, the proposed deployment of 7,500 MW of utility-scale energy storage would have a positive impact to generation reliability and resource adequacy.

ii) Transmission Reliability and Grid Resilience

Transmission reliability and grid resilience are considered by looking at how power flows would change if the proposed policy were implemented. In looking at those power flows, a key portion of the examination is how the policy would drive the need for upgrades to the transmission system. As generation resources are added to the grid, existing overloaded grid conditions or constraints can increase, and new overloads or constraints can be created.[259] The analysis conducted for this policy study identified likely transmission upgrades that would be needed. However, these are only estimates and ultimately actual costs can only be determined by the completion of full interconnection studies by the applicable RTO. Results

[259] These constraints are referred to as violations, and the goal of transmission upgrades is to remove the likelihood of the violations occurring.

are expressed in total dollar cost to portray a magnitude of the investments needed to allow for interconnection and then also on a dollars per megawatt basis which allows for the comparison of costs between different types of projects and proposals.

While this Policy Study does not directly analyze the impact of distribution-level storage systems on grid resilience and transmission reliability, findings from other states and academic entities shed light on their potential contributions. For example, an MIT Energy Initiative study noted that peak shifting facilitated by distribution-level storage generates "knock-on effects" on generation design, which is a reduction in required storage discharges during peak hours and a decrease in necessary solar capacity installations to charge up the storage. [260]

The value that distributed storage systems can provide varies depending on configuration, size, and location of the storage system. These variable aspects make it hard to quantify a specific value that fits all distributed energy storage systems. States such as New York have not determined a single value for distributed storage benefits, but rather evaluate them through different pilot rate programs such as those found in the New York Energy Storage Value Stream Reference Guide.[261] One of the value streams for energy storage under the reference guide is the customer demand delivery charge reduction contained in Rider Q. Rider Q, a pilot tariff rate in ConEd's service territory that provides alternative rate options for energy storage customers receiving standby service.[262] Rider Q was proposed to compensate customers for the value provided by distributed energy resources, particularly energy storage systems. Rider Q identifies the value of distributed energy storage as being in a range between 8%-17% of energy and demand charges, and that provides an illustrative example of the potential value of distributed storage.

The Illinois Commerce Commission has an ongoing investigation into the value of, and compensation for, distributed energy resources, including distributed storage batteries.[263] A presentation made by Enernex, the facilitator of the Commission's investigation, highlighted key components of distributed energy resources value on improving grid resilience and reliability by enhancing energy security and reducing vulnerability to centralized grid failures.[264] A presentation by the Brattle Group also describes how adding storage to

[260] MIT Energy Initiative, (n.d.). The Future of Energy Storage. https://energy.mit.edu/wp-content/uploads/2022/05/The-Future-of-Energy-Storage.pdf

[261] NYSERDA. (n.d.). *New York Energy Storage Value Stream Reference Guide for Developers and Contractors.* NYSERDA - New York State Energy Research & Development Authority. https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/Value-Stream-Reference-Guide.pdf

[262] NYSERDA. (2018). Standby Rate + Con Ed Rider Q Fact Sheet NY-BEST Summer 2018 – NYSERDA Energy Storage Program. NYSERDA - New York State Energy Research & Development Authority - NYSERDA. https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/Rider-Q.pdf

[263] Investigation into the value of, and compensation for, distributed energy resources. (n.d.). Illinois Commerce Commission. https://www.icc.illinois.gov/programs/climate-and-equitable-jobs-act-implementation-investigation

[264] Investigation Into The Value Of, And Compensation For, Distributed Energy Resources (n.d.). Illinois Commerce Commission. https://icc.illinois.gov/api/web-management/documents/downloads/public/CEJA/ICC%20Value%20of%20DER%20Workshop%20-%20Value%20of%20DER.pdf

distributed generation could provide value to the power system.[265] The values identified by Brattle start with how distributed generation (e.g., rooftop solar) adds benefits to the grid that include energy, reducing emissions, providing resilience, ancillary services, and generation capacity. The addition of behind-the-meter ("BTM") storage can increase these benefits provided by rooftop solar in some cases to provide transmission and distribution capacity. The transmission capacity value of BTM occurs would come from when storage discharges during peak hours thus reducing the long-run need for peak-driven local transmission capacity investment. To capture the transmission capacity value investment, significant levels of BTM storage adoption would be required, or alternatively, storage be paired with other demand-side resources to reach the necessary scale.

SB 1587 calls for competitive procurements of storage credits from utility-scale energy storage projects and thus it is not possible to know with certainty where future utility-scale energy storage projects would be located. As a proxy, the models used projects currently in the PJM or MISO interconnection queue. The following results are illustrative of the range of interconnection costs that utility-scale energy storage projects might face. These costs would not be directly incurred by customers, rather they are potential development costs that would be factored into the economics of any given project by its developer. A key takeaway is that the costs vary greatly by location. This makes sense as the grid is a complex network and localized conditions will differ.

[265] Illinois Commerce Commission. (2023). *Investigation into the value of, and compensation for, distributed energy resources*. https://www.icc.illinois.gov/programs/climate-and-equitable-jobs-act-implementation-investigation

Table 5-8: MISO ESS Network Upgrade Costs and Unit Costs

Queue Position	Queue Cycle	Project Size (MW)	Cost of Network Upgrades ($)	Cost of Network Upgrades ($/MW)
J1655	DPP-2020	50	$12,091,984.29	$241,839.69
J1695	DPP-2020	50	$5,975,035.02	$119,500.70
J1882	DPP-2021	45	$6,310,000.00	$140,222.22
J1973	DPP-2021	40	$1,777,500.00	$44,437.50
J1975	DPP-2021	40	$1,721,000.00	$43,025.00
J2124	DPP-2021	100	$4,016,900.00	$40,169.00
J2159	DPP-2021	50	$7,190,000.00	$143,800.00
J2161	DPP-2021	50	$922,857.85	$18,457.16
J2170	DPP-2021	150	$122,710,000.00	$818,066.67
J2195	DPP-2021	100	$8,337,700.00	$83,377.00
J2197	DPP-2021	100	$8,436,600.00	$84,366.00
J2375	DPP-2022	100	-	-
J2376	DPP-2022	60	$29,820,000.00	$497,000.00
J2377	DPP-2022	300	$6,970,000.00	$23,233.33
J2379	DPP-2022	200	$12,311,000.00	$61,555.00
J2383	DPP-2022	100	$2,350,000.00	$23,500.00
J2402	DPP-2022	200	$1,290,000.00	$6,450.00
J2413	DPP-2022	150	$13,091,560.00	$87,277.07
J2426	DPP-2022	200	$39,830,000.00	$199,150.00
J2532	DPP-2022	200	$18,790,000.00	$93,950.00
J2536	DPP-2022	200	$4,360,000.00	$21,800.00
J2551	DPP-2022	110	$13,270,000.00	$120,636.36
J2552	DPP-2022	80	$8,180,000.00	$102,250.00
J2575	DPP-2022	198	$23,350,000.00	$117,929.29
J2607	DPP-2022	200	$7,480,000.00	$37,400.00
J2627	DPP-2022	150	$14,880,000.00	$99,200.00
J2647	DPP-2022	300	$6,100,000.00	$20,333.33
J2724	DPP-2022	300	$11,290,000.00	$37,633.33
J2853	DPP-2022	100	$6,570,300.00	$65,703.00
J2974	DPP-2022	50	$29,256,500.00	$585,130.00
J2998	DPP-2022	200	$34,449,313.92	$172,246.57
J3011	DPP-2022	100	$17,587,400.00	$175,874.00
J3031	DPP-2022	200	$13,210,000.00	$66,050.00
J3200	DPP-2022	250	$18,782,500.00	$75,130.00
J3216	DPP-2022	300	$6,970,000.00	$23,233.33

Table 5-9: PJM ESS Cost of Network Upgrades and Unit Costs

Queue Position	Project Size (MW)	Cost of Network Upgrades ($MM)	Cost of Network Upgrades ($/MW)
AG1-298	500	$67.47	$134,940
AG2-357	250	$13.77	$55,080
AG2-545	400	$19.65	$49,125
AF2-441	250	$50.08	$200,320
AH2-015	110	$157.52	$1,432,000
AH2-204	170	$113.24	$666,118
AH2-259	150	$119.25	$795,000
AH2-290	60	$19.29	$321,500
AH2-339	110	$425.05	$3,864,091
AH2-341	250	$220.11	$880,440

Based on the current status of PJM's Transition Cycle #1, Transition Cycle #2, and Cycle #1 it is not possible at this point to accurately determine the cost allocation of network upgrades for a project that will be studied as part of Cycle #1. As other projects enter and withdraw from the generation queue and network upgrades for those projects are developed, the cost responsibility for future projects will become clearer.

iii) Impact on Electricity Costs

The modeling of impacts on electricity costs was conducted using Aurora, a tool that conducts a production cost simulation of the electric system. Production simulation models are widely used in the power industry to estimate the cost of electricity and to simulate the operation of generation and transmission systems under a specified set of assumptions about electricity demand, fuel prices, and generation resource mix and operating performance.[266]

The proposed 7,500 MW of utility scale storage projects would impact electricity costs in two ways.

First, netting out an estimate of the revenue the projects would receive from capacity and energy sales leaves an estimated $239.1 million per year difference in 2022 dollars between expected market revenues and revenues required to cover costs. That $239.1 million per

[266] The costs and emissions reduction results presented in this section have been revised from the draft Policy Study to reflect several corrections in modeling. The most significant revisions include those described in the Agency's February 8 errata that updated the reporting of energy revenue, and revisions made after receiving comments on the draft Policy Study that include updating retirement schedules for certain plants, adopting an adjustment to the capacity price for the ComEd zone, and including the investment tax credit for the proposed offshore wind project. For details on those corrections please see Section 8.d.i.i.

year difference constitutes the annualized cost that would be supported by Illinois ratepayers through the purchase of energy storage credits from the projects.

Second, deployed storage projects supported through SB 1587 would benefit ratepayers by impacting wholesale energy costs, lowering those costs for Illinois ratepayers by $739.1 million over 20 years, or $22.6 million on an annualized basis in 2022 dollars.

Based on similar modeling, deploying 1,000 MW of distributed energy storage would carry an annualized cost of $82.23 million, while contributing $4.0 million in lower wholesale electricity costs.

For the average Ameren residential customer, the modeling indicates that the monthly bill impact from 2030-2040 of implementing the energy storage policy would be $2.88 in nominal dollars and $1.89 in real 2022 dollars. For the average ComEd customer, the impact would be $1.85 in nominal dollars and $1.21 in 2022 real dollars. This difference is due to the lower average consumption of ComEd customers compared to Ameren customers. For more information on these comparisons, see Section 8.d.ix.

The introduction of storage resources had a significant impact on the dispatch of ZEFs. Storage reduced the output of ZEFs by 63%. The introduction of storage resources also effectively "idled" approximately 2,100 MW of ZEF capacity that was included in the base case. The idled units had zero output in the second half of the study period (2040-2049) in the Storage case.[267]

iv) Impact on Emissions

The production cost simulation estimates emissions abatement that could be created from electricity generated by the combustion of fossil fuels in the absence of additional renewable generation modeled by each policy proposal. Emissions from the combustion of fossil fuels—specifically, particulate matter ("$PM_{2.5}$"), sulfur dioxide ("SO2") and nitrogen oxides (NOx)—are linked to a wide range of adverse health effects and carbon dioxide ("CO_2") emitted by the combustion of fossil fuels, contributes to climate change. Table 5-10 contains the avoided emissions projected from the proposed energy storage program over a 20-year period from 2030 to 2049.

Table 5-10: Energy Storage Emissions Impacts (2030-2049)

CO_2 (Tons)	CO_2 (tons/MWh)	SO_2 (Tons)	SO_2 (lbs./MWh)	NO_x (Tons)	NO_x (lbs./MWh)	$PM_{2.5}$ (Tons)	$PM_{2.5}$ (lbs./MWh)
27,309,080	0.17	8,223	0.10	15,528	0.19	701	0.01

[267] ZEFs are Zero Emissions Fuel units included in the Aurora production cost modeling to establish the base case that policy scenarios are compared against. ZEFs are called upon sparingly in the Aurora production cost modeling but are critical during stressed system conditions. 8.5 GW of ZEFs are included in the modeling. See Section 8.d.v for more details on the use of ZEFs.

As described in more detail in Chapter 8, estimating the dollar impact of avoided emissions reductions is a complex and uncertain exercise, and the range of estimates can have a ten-fold span. Chapter 8 summarizes recent literature on emissions costs. This includes a range of CO2 prices based on the Social Cost of Carbon established by the Interagency Working Group in 2016, and more recent estimates developed by the U.S. EPA that are currently under consideration. Based on those ranges, an estimate of the monetized value of the avoided emissions reductions from the proposed energy storage program over the 20-year are shown in Table 5-11.

Table 5-11: Energy Storage Range of Value of Emissions Impacts (2030-2049, Shown in 2022 Real Dollars

CO_2	\$423 million - \$4.15 billion
SO_2	\$65 – 288 million
NO_x	\$434 -259 million
$PM_{2.5}$	\$9 - 85 million

v) Economic Impacts

Economic impacts and job creation modeling was conducted using IMPLAN, a modeling tool used widely in many industries. A set of inputs are entered into the IMPLAN model and the software generates results that include estimates of output, value added, and jobs created. If deemed necessary, the capital and operating expenditures include high and low values to reflect into the model a range of uncertainties contained in the inputs. The results are reported in both total dollar amounts and as function of the size of the project (MW) and the energy output (\$/TWh). Job creation is reported as Fulltime Equivalents in Illinois (e.g., one FTE is 2,080 hours of work, which could all occur in one year, or be spread out across several years), and is expressed as both totals and as a function of the size of the project and the energy output.

Energy storage was modeled in two scenarios. The first scenario was for the deployment of 7,500 MW of utility-scale energy storage, and the second scenario was for the deployment of 1,000 MW of distributed storage, of which 200 MW was for residential projects and 800 MW was for commercial or community solar projects. The inputs for capital and operating expenditures are higher for distributed storage due to higher equipment and labor costs for smaller-scale systems.

Table 5-12: Total (Direct, Indirect and Induced) Value Added

Case	Total Value Added		
	$	$/MW	$/TWh
Utility-Scale Energy Storage Low CapEx	$1,969,419,166	$262,589	$12,060,567
Utility-Scale Energy Storage High Capex	$8,836,463,187	$1,178,195	$54,113,801
Utility-Scale Energy Storage Low Opex	$1,138,331,501	$151,778	$6,971,052
Utility-Scale Energy Storage High Opex	$4,490,941,843	$598,792	$27,502,172
Distributed Energy Storage Low Capex	$510,450,822	$510,451	$23,444,703
Distributed Energy Storage High Capex	$2,036,437,850	$2,036,438	$93,532,382
Distributed Energy Storage Low Opex	$259,859,576	$259,860	$11,935,196
Distributed Energy Storage High Opex	$1,005,621,973	$1,005,622	$46,187,620

Table 5-13: Total (Direct, Indirect and Induced) Job Creation

Case	Total Job Creation		
	FTE-Years	FTE-Years/MW	FTE-Years/TWh
Utility-Scale Energy Storage Low Capex	16,473	2.196	100.877
Utility-Scale Energy Storage High Capex	62,107	8.281	380.338
Utility-Scale Energy Storage Low Opex	9,555	1.274	58.515
Utility-Scale Energy Storage High Opex	31,766	4.235	194.534
Distributed Energy Storage Low Capex	4,198	4.198	192.807
Distributed Energy Storage High Capex	14,329	14.329	658.136
Distributed Energy Storage Low Opex	2,191	2.191	100.608
Distributed Energy Storage High Opex	7,127	7.127	327.345

6) New Utility-Scale Offshore Wind Project in Lake Michigan

This Policy Study tasked the Agency with modeling the feasibility of one pilot offshore wind project sited in Lake Michigan. This project would be at least 200 MW in size and interconnected within the PJM regional system. HB 2132 would require this project to utilize a fully executed project labor agreement with any applicable local building and construction trades council for the length of the renewable energy credit contract. The project would be required to have a defined, comprehensive, and detailed equity and inclusion plan. That plan would be required to be crafted to create opportunities for underrepresented local populations and equity investment eligible communities that this project would impact. The project would also need to acquire proper permitting pursuant to the Rivers, Lakes, and Streams Act from the Illinois Department of Natural Resources ("IDNR") for a site that is in a preferred area pursuant to Section 15 of the Lake Michigan Wind Energy Act. This outline is the basis of the Agency's research and modeling for a pilot offshore wind project in Lake Michigan.

a) Introduction of U.S. Offshore Wind

Offshore wind in the United States is a growing sector of the energy economy. It provides the promise of large, utility-scale clean energy generating facilities that could be located closer to geographically constrained high-load demand areas compared to land-based wind facilities. Offshore wind allows for larger turbines, bigger projects, and access to stronger oceanic winds comparted to land-based turbines.[268] Investment in offshore wind is anticipated to grow in the coming decade, despite some recent setbacks. Offshore wind has the potential to supply substantial amounts of clean energy to meet the United States' power demand, with extraneous benefits that include creating domestic jobs and addressing climate change through carbon-free power generation. Offshore wind projects also have the potential to provide reliable and increasingly more affordable renewable power when located near coastal cities.[269] Additionally, offshore wind can meet energy load need where there is geographic constraint for site availability for large-scale renewable developments on land. This opportunity to supply local power to meet coastal cities' energy demand is encouraging oceanic states to adopt proactive offshore wind energy policies to capture the benefits of offshore wind.[270] The extraneous benefits that can be claimed from offshore wind include economic growth, energy independence, and reduced greenhouse gas emissions for communities that offshore wind projects serve.

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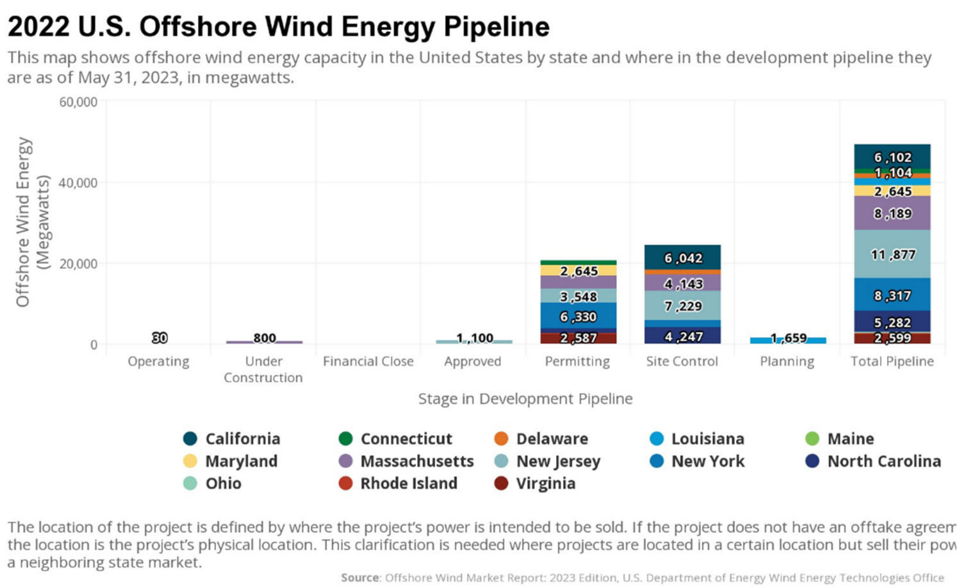
[268] Beiter, P., W. Musial, L. Kilcher, M. Maness, and A. Smith. 2017. An Assessment of the Economic Potential of Offshore Wind in the United States from 2015 to 2030 (Technical Report). NREL/TP-6A20-67675. National Renewable Energy Laboratory (NREL), Golden, CO (United States).

[269] Shen, W., Chen, X., Qiu, J., Hayward, J. A., Sayeef, S., Osman, P., & Dong, Z. Y. (2020). A comprehensive review of variable renewable energy levelized cost of electricity. *Renewable and Sustainable Energy Reviews*, *133*, 110301.

[270] Seven states have enacted statutory procurement mandates, which totals to about 42,000 MW anticipated by 2040, with six additional states with offshore-wind-specific planning targets (DOE/GO-102023-6059, 2023)

The U.S. Department of the Interior Bureau of Ocean Energy Management ("BOEM")'s Renewable Energy Program supports offshore wind turbines for utility-scale development, as well as through providing tax incentives and loan guarantees for energy production of various types.[271] The program began in 2005 and has since executed 301 leases and grants issued to wind developers.[272] Of those 301 leases or grants, 37 of them are active or consolidated. Currently, the U.S. East Coast sees the greatest offshore wind development activity. A 2021 report from DOE found that states with current offshore procurement targets, in aggregate, wish to deploy at least 39,298 MW of offshore wind capacity by 2040.[273] As of December 2022, about 300 GW of wind capacity were in transmission interconnection queues, with 113 GW being from offshore wind and 24 GW from hybrid projects (mostly wind paired with storage).[274] As of May 2023, DOE estimates the U.S. offshore wind energy pipeline has about 52,000 MW of capacity.[275]

Figure 6-1: Offshore Wind Pipeline



This Policy Study looks at the feasibility of an offshore wind project as proposed in HB 2132 and models a 200 MW wind turbine project within the Illinois boundary waters of Lake

[271] The Energy Policy Act of 2005, 42 U.S.C. ch. 149 § 15801 et seq., 16 U.S.C. ch. 46 § 2601 et seq., 42 U.S.C. ch. 134 § 13201 et seq.,

[272] Lease and Grant Information | Bureau of Ocean Energy Management (boem.gov)

[273] Office of Energy Efficiency and Renewable Energy (EERE); Wind Energy Technologies Office (WETO), McKenzie, N., & Maher, M., Offshore Wind Energy Strategies (2022). U.S. Department of Energy. https://www.energy.gov/sites/default/files/2022-01/offshore-wind-energy-strategies-report-january-2022.pdf

[274] Wiser, R., Bolinger, M., Hoen, B., Millstein, D., Rand, J., Barbose, G., ... & Paulos, B. (2023). *Land-Based Wind Market Report: 2023 Edition*. Lawrence Berkeley National Laboratory (LBNL), Berkeley, CA (United States).

[275] This capacity is the sum of installed projects, projects under construction, projects approved for construction, projects undergoing various state and federal permitting processes, existing lease areas, and the development potential of yet to be leased wind energy areas; Musial, W., Spitsen, P., Duffy, P., Beiter, P., Shields, M., Hernando, D. M., Hammond, R., Marquis, M., King, J., & Sathish, S. (2023, August). Offshore Wind Market Report: 2023 Edition (No. DOE/GO-102023-6059). EERE Publication and Product Library, Washington, DC (United States)

Michigan. This Study also looks at the successes and challenges currently facing the offshore wind industry in the U.S. and what can be learned from proposed projects in the Great Lakes, such as Ohio's Icebreaker project.

i) Offshore Wind Types and Offshore Technology

Offshore wind technology saw its first commercial operation success in 1991 with the commissioning of Vindeby Wind Farm, owned by Ørsted, off the coast of Denmark.[276] While the project was decommissioned in 2017, there have been many advancements in wind technology since Vindeby's energization. Wind turbine size and capacity affects all aspects of a project. Ocean-based offshore wind development increasingly relies on larger turbine size (in MW) due to economies of scale needed to build a commercially operated project, with manufacturers beginning to develop offshore wind turbines with capacities of up to 15 MW.[277] As of 2023, the average size of installed turbine capacity globally averages 7.7 MW, with an average hub height[278] of about 116 meters (this includes both land-based and offshore wind). In contrast, land-based turbines in the U.S. have an average nameplate capacity of only 3.2 MW with an average hub height of about 98.1 meters.[279]

There are two main categories of offshore wind substructures: fixed bottom foundation and floating bottom foundation (See Figure 6-2 and Figure 6-3). Fixed bottom foundations are considered industry standard. Similar to Vindeby Wind Farm, monopiled fixed-bottom substructures are the most prevalent, with 50,623 MW of fixed bottom offshore wind turbines operating worldwide as of 2021.[280]

Figure 6-2 shows a visualization of varying types of fixed-bottom offshore wind turbine substructures,[281] including monopile foundations which are driven into the seabed by piledrivers. DOE reports that 56.5% of announced offshore projects intend on using a monopiled substructure,[282] and 60.2% of existing capacity worldwide uses monopile foundations.[283]

[276] Ørsted. (n.d.). 1991-2001 The First Offshore Wind Farms (Chapter 2/6). Ørsted. Fredericia Denmark

[277] Musial, W., Spitsen, P., Duffy, P., Beiter, P., Shields, M., Hernando, D. M., Hammond, R., Marquis, M., King, J., & Sathish, S. (2023, August). Offshore Wind Market Report: 2023 Edition (No. DOE/GO-102023-6059). EERE Publication and Product Library, Washington, DC (United States).(Musial et al., 2023)

[278] A wind turbine's hub height is the distance from the ground to the middle of the turbine's rotor. Hartman, L. (2023, August 24). Wind Turbines: the Bigger, the Better. EERE. https://www.energy.gov/eere/articles/wind-turbines-bigger-better

[279] Wiser, R., Bolinger, M., Hoen, B., Millstein, D., Rand, J., Barbose, G., ... & Paulos, B. (2023). *Land-Based Wind Market Report: 2023 Edition*. Lawrence Berkeley National Laboratory (LBNL), Berkeley, CA (United States).

[280] Musial, W., Spitsen, P., Beiter, P., Duffy, P., Marquis, M., Hammond, R., ... & Shields, M. (2022). *Offshore wind market report: 2022 edition* (No. DOE/GO-102022-5765). EERE Publication and Product Library, Washington, DC (United States).

[281] Illustration by Stein Housner, National Renewable Energy Laboratory (NREL)

[282]Musial, W., Spitsen, P., Duffy, P., Beiter, P., Shields, M., Hammond, R., Marquis, M., (2023, August). Offshore Wind Market Report: 2022 Edition (No. DOE/GO-102023-6059). EERE Publication and Product Library, Washington, DC (United States).

[283] 59,009 MW of global operating substructure capacity in 2022. (Musial et al., 2023)

Figure 6-2: Fixed Bottom Foundations

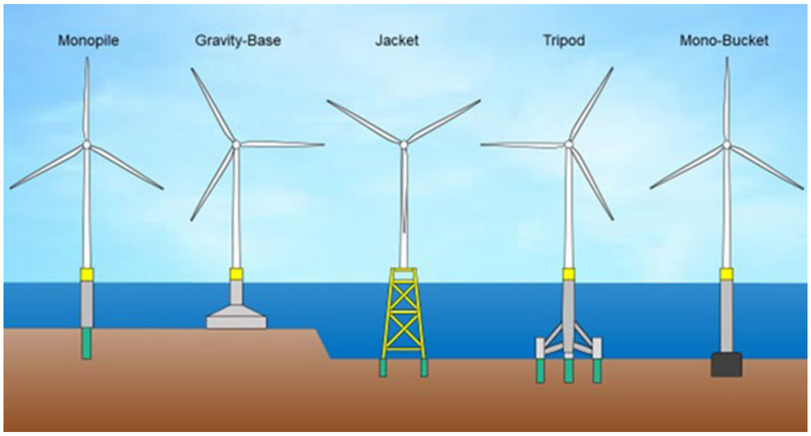
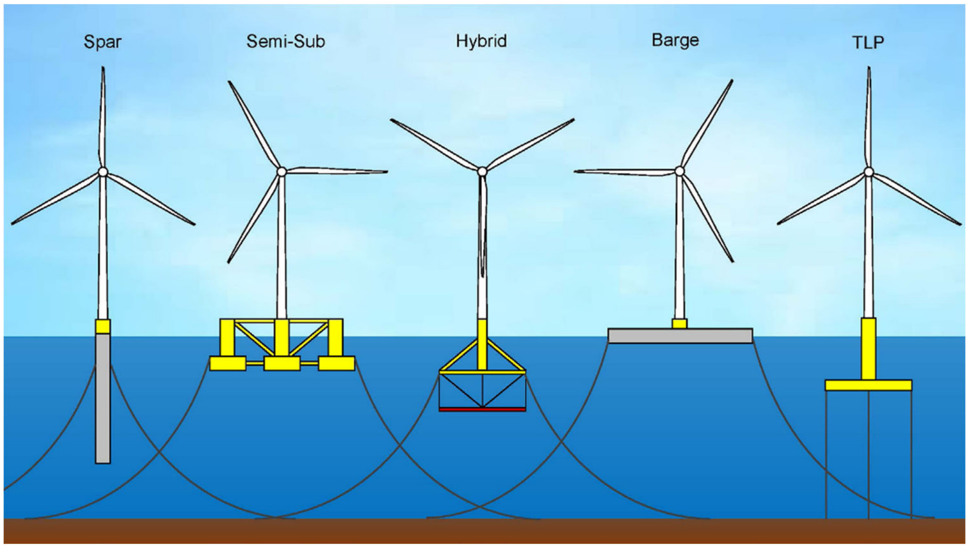


Figure 6-3: Floating Foundations



Though monopiled substructures are the incumbent technology type, as new projects are increasingly sited in deeper waters, jackets are being seen a more attractive fixed bottom foundation type than monopiled structures. Jacket foundations as seen in Figure 6-2 typically contain four legs connected by braces, similar to offshore oil and gas platforms. In 2022, jacket substructure types made up 10.4% of announced offshore wind projects and are expected to grow to 14.8% of future offshore wind projects.[284] The first U.S. commercial offshore wind farm, Block Island, uses a jacket foundation.[285]

In addition to jacket substructures, gravity-base foundations are projected to grow in market share. Unlike monopile substructures which are driven into the seabed via piledriving, and impact marine animals with noise pollution during construction, gravity-base foundations merely sit on the seabed.[286] However, gravity-based foundations come with construction challenges. For example, proper seabed preparation is needed when sited on softer soils, and dredging is typically required to prepare the soil for construction. According to DOE, for any lake-based wind projects, gravity-based substructures, tripods,[287] and monobuckets,[288] could be the most suitable option for rocky lakebed areas where pile driving may be difficult. These options can also be useful for when underwater pile driving noise needs to be avoided to protect wildlife.[289] NREL concurs that gravity-based foundations, tripods, and monobuckets are more suitable fixed-bottom substructures for Great Lakes wind than monopiles and jackets.[290, 291] While ocean-based offshore wind faces challenges, NYSERDA, in conjunction with NREL, conducted a classification of conventional fixed-bottom and floating substructures to identify ideal substructure types for the Great Lakes within New York's territory.[292] The classification assessed the feasibility of substructure type in the Great Lakes based on installation ability, lakebed compatibility, ice-structure interaction, local manufacturability, system cost, and technology readiness. The assessment findings are consistent with those from DOE.

In addition to fixed-bottom substructures, floating turbines are quickly gaining market share for new oceanic projects and for projects that favor semisubmersible substructures. By DOE's estimate, worldwide, 79.6% of floating projects in development "intend to use a

[284] 109,698 MW of future projects that have publicly announced plans, monopiles are anticipated to remain the most common choice for substructure with 47.5% of announced capacity being monopiled substructure project types technologies (Musial et. al, 2023).

[285] Fried, Samantha, Desen Ozkan, Katarina Halldén, Bridget Moynihan, John DeFrancisci, Dan Kuchma, Chris Bachant, and Eric Hines. 2022. Low-Carbon, Nature-Inclusive Concrete GravityBased Foundations for Offshore Wind Turbines. Technical Report OSPRE Report 2022-02. Offshore Power Research & Education Collaborative. Massachusetts, USA: Tufts University. https://dl.tufts.edu/pdfviewer/t722hq84r/pk02cr377

[286] Fried et. al, 2022

[287] Tripod foundations consist of three foundation piles connecting to a base above the waterline.

[288] Monopiled substructures with a suction bucket foundation where once lowered to the seabed the bucket is flooded until the bucket is pushed into the seabed, pumps create a pressure differential by pumping water out of the suction bucket and forcing it deeper into the seabed. Grismala, R. (2022). Summary of Existing Foundations, Installation Methods, and Effects. In U.S. Offshore Wind Noise Reduction Workshop. National Renewable Energy Laboratory (NREL) & Pacific Northwest National Laboratory (PNNL).

[289] Musial et. al, 2022

[290] Musial, Walter, Rebecca Green, Ed DeMeo, Aubryn Cooperman, Stein Housner, Melinda Marquis, Suzanne MacDonald, Brinn McDowell, Cris Hein, Rebecca Rolph, Patrick Duffy, Gabriel R. Zuckerman, Owen Roberts, Jeremy Stefek, and Eduardo Rangel. 2023. Great Lakes Wind Energy Challenges and Opportunities Assessment. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-84605. https://www.nrel.gov/docs/fy23osti/84605.pdf

[291] NREL notes that "Tripods are technically feasible but are perceived to be expensive, and monobuckets are less mature and as a result may have a higher risk" (Musial, 2022). Tripods make up 1.8% of current existing offshore wind MW capacity (Musial et al., 2023).

[292] New York State Energy Research and Development Authority (NYSERDA). 2022. "New York State Great Lakes Wind Energy Feasibility Study: Substructure Recommendations," NYSERDA Report Number 22-12e. Prepared by the National Renewable Energy Laboratory, Golden, CO nyserda.ny.gov/publications

semisubmersible substructure."[293] DOE's 2022 Offshore Wind Market Report shows a general trend in offshore wind projects in early stages of development are larger, further from land, and are in deeper water.[294] Larger project size correlates to lower project costs due to economies of scale.[295] Additionally, externalities from technology advancements in electrical grid infrastructure, such as high-voltage direct-current technology, enables further project siting from land. Increased demand contributing to near-shore site scarcity also encourages development deeper offshore. These siting trends favor floating or semi-submersible substructures and encouraging floating offshore wind project expansion from demonstration scale to utility scale project size will be critical in coming years for these technologies to take hold.

NYSERDA's 2022 Great Lakes Wind Energy Feasibility Study found that for Lake Erie's relatively shallow depths,[296] a fixed-bottom substructure is assumed to be the only technology that will be used in the Lake due to cost effectiveness and lakebed conditions.[297] This is consistent with development in Lake Erie for the proposed IceBreaker Project (discussed below). However, Lake Michigan is significantly deeper than Lake Erie, with depths in the Illinois territory up to 100 meters (See Figure 6-4 below) and this could impact what designs would be considered for a project sited in Illinois. The NYSERDA 2022 report does not recommend fixed bottom substructures for use in the deeper waters of Lake Ontario. NYSERDA recommends floating substructures for any development in Lake Ontario, as it is optimally conditioned to support floating substructure technology with its deeper waters. Lake Michigan has similar depths to Lake Ontario and could also be potentially suited for floating substructures.[298]

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[293] Musial et. al, 2022

[294] Musial et. al, 2022

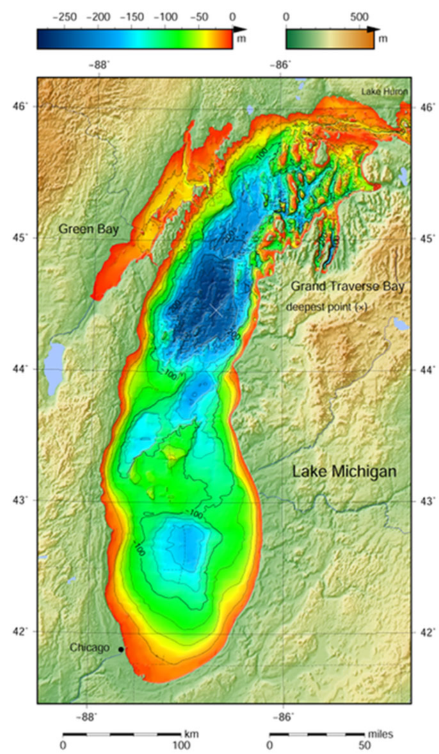
[295] Musial, W., Spitsen, P., Beiter, P., Duffy, P., Marquis, M., Cooperman, A., ... & Shields, M. (2021). *Offshore wind market report: 2021 edition* (No. DOE/GO-102021-5614). EERE Publication and Product Library, Washington, DC (United States).

[296] Lake Erie with an average depth of 19m with its deepest point at 64m, this is in comparison with Lake Michigan having an average depth of 85m. U.S. EPA. (2023, December 13). Physical features of the Great Lakes | US EPA. Physical Features of the Great Lakes.

[297] New York State Energy Research and Development Authority (NYSERDA). 2022. "New York Great Lakes Wind Energy Feasibility Study," NYSERDA Report Numbery 22-12. Prepared by the National Renewable Energy Laboratory, Advisian Worley Group, and Brattle Group/Pterra Consulting. nyserda.ny.gov/publications

[298] New York State Energy Research and Development Authority (NYSERDA). 2022. "New York State Great Lakes Wind Energy Feasibility Study: Substructure Recommendations," NYSERDA Report Number 22-12e. Prepared by the National Renewable Energy Laboratory, Golden, CO nyserda.ny.gov/publications

Figure 6-4: Lake Michigan Depths[299]



NREL, DOE, and NYSERDA are each optimistic that in the future floating substructures could become economically viable and easier to manufacture, install, and decommission relative to fixed-bottom substructures. Floating turbines use buoyant substructures that are moored to the lakebed with chains, ropes, and anchors (See Figure 6-2 above). This would reduce lakebed disruptions with less of the site being used for substructure installation. A floating turbine could potentially be more aerodynamic, hydrodynamic, and ice-loading than a fixed bottom substructure, overcoming the harsh meteorological conditions faced by a project sited in the Great Lakes. NYSERDA's report revealed that offshore wind substructure developers demonstrated interest in developing Great Lakes-specific floating substructures to be optimized for Great Lakes conditions.[300] In DOE's 2023 report, the Department stated, "May 2022, the 2-MW DemoSATH[301] demonstration project completed mooring installation at the Biscay Marine Energy Platform test site off the coast of the Spanish Basque Country."[302] As of July 2023, the project has not been energized. However, once energized it will be the

[299] Wikipedia. (2015, April 4). File:Lake Michigan bathymetry map.png - wikipedia.

[300] New York State Energy Research and Development Authority (NYSERDA). 2022. "New York Great Lakes Wind Energy Feasibility Study," NYSERDA Report Numbery 22-12. Prepared by the National Renewable Energy Laboratory, Advisian Worley Group, and Brattle Group/Pterra Consulting. nyserda.ny.gov/publications

[301] DemoSATH is a floating offshore wind power pilot project being developed off the Basque coast of Armintza in northern Spain by RWE Renewables; Rwe. (n.d.). Floating offshore wind in Spain: Floating Offshore Wind at RWE. RWE. https://www.rwe.com/en/our-energy/discover-renewables/floating-offshore-wind/demosath/

[302] Jaén, Coral, Sinje Vogelsang, and Charlotte Holst Frahm. 2022. "DemoSATH floating wind project successfully completes the offshore mooring installation." Press Release. https://www.rwe.com/-/media/RWE/documents/07-presse/rwe-renewables/2022/2022-05-17-demosath-floating-wind-project-successfully-completes-the-offshore-mooring-installation.pdf.

first floating offshore wind project in the world. Immediate construction of a floating wind project in the Great Lakes is unlikely in the short term, but advancements in turbine substructure technology are making the industry hopeful for future consideration for lake-based floating turbines.

While there are currently no proposed designs for floating offshore wind turbines in the Great Lakes, future designs may want to incorporate shoreline assembly and include lower waterline profiles in their designs to avoid the ice loading constraints for potential Great Lakes' projects. Future Great Lakes turbine design challenges need to address known supply-chain limitations, such as the narrow width of the St. Lawrence River (through which offshore construction vessels would travel to reach the Great Lakes) and optimize vessel design to accommodate canal locks. Due to the design challenges and trends facing floating wind technology in the Great Lakes, a feasibility assessment must be performed to determine the suitability of each of the floating substructure types for possible deployment in the Great Lakes. Previous feasibility studies done by NYSERDA for floating and fixed bottom substructures considered Lakebed compatibility (for fixed-bottom substructures), ice interactions with waterline profiles, local manufacturability, and overall estimated cost.[303] If offshore wind development in Lake Michigan is to move forward, technological barriers and optimizing turbine design for the Great Lakes will need to be studied to reduce costs for potential developments. As it currently stands, there is no commercial scale floating offshore wind under development and no freshwater wind farms energized in the world.[304]

Any near-term project proposals will need to rely on a fixed-bottom substructure until there is floating substructure technology actualized for the Great Lakes. The proposed Lake Erie LeedCo Icebreaker project (discussed further in this chapter) submitted a monobucket design as the turbine substructure foundation. This proposed hybrid approach has the combined benefits of a gravity base, a monopile, and a suction bucket. The developer claimed this substructure design considers factors such as 50-year weather extremes, average wind speed, wind gusts, turbulence intensity, waves, and ice loads to optimize a turbine output at 3.45 MW output per turbine.[305]

While there are several substructure designs that could be considered for a lake-based wind project, for this Policy Study the Agency has assumed a fixed bottom substructure with a turbine size of about 6 MW.

ii) Offshore Wind Development in the Great Lakes

Offshore wind development has increased in the world's oceans, however, offshore wind development in the Great Lakes presents different challenges for developers. Offshore wind

[303] NYSERDA 22-12

[304] Musial et. al, 2023

[305] The total number of turbines proposed to be installed would be 6, "Accounting for the total generating capacity of approximately 21 MW, anticipated operating times, and turbine capacity factors, the Proposed Project would generate approximately 75,000 MWh of electricity each year." (Final Environmental Assessment LEEDCo Project Icebreaker, 2018)

in the Great Lakes region will require different solutions than those used in coastal states to address deficiencies. There is also a possibility that incumbent industry knowledge in ocean states may not address the unique offshore wind deployment issues faced by Great Lakes developers. Due to these differences and without substantial investment, technological advancement, collaborative infrastructure planning, proactive stakeholder engagement, technology readiness, and cost reduction for Great Lakes wind energy generation is more likely to be delayed relative to ocean-based development.[306] Further, inadequate research in Great Lakes wind development and insufficient research on supply chain development will likely result in higher costs of entry than late adopters of lake-based offshore wind and will result in developments bearing cost overruns.

A 2023 NREL report analyzed potential issues that may impact offshore wind development in the Great Lakes.[307] NREL's report also developed comprehensive research plans to address and resolve these issues from a regional perspective. In their analysis, NYSERDA's 2022 Great Lakes Wind Energy Feasibility Study[308] used the LCOE corresponding to hypothetical Offshore wind REC ("OREC") strike prices that a potential project would offer in response to a NYSERDA solicitation and found that a commercially-sized project between 400 and 800 MW would have a potential strike price of between $98-$138.[309] When comparing this value to NYSERDA's Tier 1[310] and offshore wind projects that have already been awarded contracts by NYSERDA, Tier 1 contracts have a strike price ranging between $42-$63, meaning Great Lakes Wind strike prices would be considerably higher than those seen for Tier 1 projects.[311] Similar to NYSERDA, the Agency conducted further cost analysis as described in Chapter 8.

Neither NREL's Great Lakes report nor NYSERDA's feasibility study considered current unresolved Great Lakes offshore wind development challenges, such as logistics around the narrow width of the river and canal locks. Additionally, there are outstanding infrastructure logistics that need to be addressed to achieve a successful lake-based wind deployment to commercial scale. Both reports outline that one of the largest hurdles to be addressed, despite perfectly modelled cost scenarios, is that there is significant concern that locks and

[306] Musial et al., 2023; NYESERDA 22-12, 2022

[307] Musial, Walter, Rebecca Green, Ed DeMeo, Aubryn Cooperman, Stein Housner, Melinda Marquis, Suzanne MacDonald, Brinn McDowell, Cris Hein, Rebecca Rolph, Patrick Duffy, Gabriel R. Zuckerman, Owen Roberts, Jeremy Stefek, and Eduardo Rangel. 2023. Great Lakes Wind Energy Challenges and Opportunities Assessment. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-84605. https://www.nrel.gov/docs/fy23osti/84605.pdf

[308] Prepared in response to New York Public Service Commission Order Case 15-E-0302.

[309] New York State Energy Research and Development Authority (NYSERDA). 2022. "New York State Great Lakes Wind Energy Feasibility Study: Cost Analysis," NYSERDA Report Number 22-12g. Prepared by the National Renewable Energy Laboratory, Golden, CO. nyserda.ny.gov/publications

[310] Tier 1 RECs are produced by generators using new renewable energy resources that entered commercial operation on or after January 1, 2015.

[311] The LCOE estimated for a Great Lakes Wind project, in NYSERDA's analysis does not account for total costs that are included in a all-in bid for (O)REC project costs, additional costs needed to build out the ports, vessels, and supply chain required for Great Lakes Wind is not included in the LCOE.

canals of the St. Lawrence seaway will limit large scale deployment of offshore wind in the Great Lakes due limiting the sizes of vessels that may travel through.

Due to vessel transit limitations to the Great Lakes and the capacity limitations of land-based cranes that can operate in the lakes and adjacent ports, offshore wind turbines in the Great Lakes may need to be smaller than conventional offshore wind turbines. The locks of the St. Lawrence River are too narrow for most conventional oceanic installation vessels to navigate, and current ports and cranes on the Great Lakes are currently not large enough to support wind farm development.[312,313] Despite limitations on vessel size, certain fixed bottom substructure types for lake-based offshore wind turbines may be assembled, installed, and commissioned onshore, and may be towed out to the project site. These factors minimize the need for heavy-lift installation vessels and may be beneficial for operations and maintenance ("O&M") development timelines.

There is currently no energized offshore wind project in any Great Lake. The first proposed offshore wind project in the Great Lakes was a 20.7 MW offshore wind project ("Icebreaker") approximately 8 miles offshore from Cleveland, Ohio in Lake Erie.[314,315] Icebreaker was overseen by the Lake Erie Energy Development Corporation ("LEEDCo") led by the Great Lakes Energy Development Task Force in Ohio. Icebreaker ran into many challenges, and after much delay, in 2022, the Ohio Supreme Court approved the project.[316] Further, the U.S. DOE was to provide federal funding to LEEDCo for the project. However, without adding tariffs to ratepayers' utility bills to subsidize the project costs, DOE funding alone was not sufficient to recoup total project costs. While Public Power agreed to buy one third of the 20.7 megawatts of electricity that Icebreaker would generate, LEEDCo was not successful in securing additional financing by the end of fiscal year 2023. As of October 2023, DOE is no longer funding Icebreaker (DOE rescinded what's left of the $50 million grant extended to LEEDCo nearly a decade ago).[317] DOE's funding rescission and current high interest rates have left Icebreaker less desirable to potential developers and investors. Thus, in early December 2023, LEEDCo's CEO announced that the project is temporarily halted.[318]

[312] The lock size in the St. Lawrence canals allows maximum vessel size of 225.5 m long, 23.77 m wide and 8.08 m in draft (boat draft is the minimum amount of water required for a boat to float without touching the bottom of the canal). This also limits the height for overhead clearance, or air draft to not exceed 35.5. (Great Lakes St. Lawrence Seaway Development Corporation, n.d.).

[313] EA-2045: Final Environmental Assessment. Energy.gov. (n.d.). https://www.energy.gov/nepa/articles/ea-2045-final-environmental-assessment

[314] Kroll, K. (2009, February 12). Great lakes energy development task force tracks lake Erie ice movements. Cleveland.Com. Retrieved from https://www.cleveland.com/business/2009/02/post_30.html

[315] Krouse, P. (2022, September 16). Icebreaker Wind Project proposed for Lake Erie needs to find more financing soon. cleveland.com. https://www.cleveland.com/news/2021/10/icebreaker-wind-project-proposed-for-lake-erie-needs-to-find-more-financing-soon.html

[316] Hancock, L. (2022, August 10). In 6-1 decision, Ohio Supreme Court approves Icebreaker Wind Project in lake erie. cleveland.com. https://www.cleveland.com/news/2022/08/in-6-1-decision-ohio-supreme-court-approves-icebreaker-wind-project-in-lake-erie.html

[317] Department of Energy (2023, October). The U.S. Department of Energy is no longer funding this project. https://www.energy.gov/nepa/ea-2045-lake-erie-energy-development-corporations-project-icebreaker-offshore-wind-advanced

[318] Krouse, P. (2023, December) Icebreaker Wind project halted, no plans to resurrect effort to put wind turbines in Lake Erie. Cleveland.com. https://www.msn.com/en-us/money/other/icebreaker-wind-project-halted-no-plans-to-resurrect-effort-to-put-wind-turbines-in-lake-erie/ar-AA1ld3Hz

iii) Offshore Wind Development in Lake Michigan

In 2011, the now inactive Great Lakes Wind Commission published *Best Practices for Sustainable Wind Energy Development in the Great Lakes Region.*[319] The report recommended best practices and policies for states to take into consideration, covering the lifecycle of a Lake Michigan offshore wind project including development, operations, and decommissioning.[320] The report also recommends that developers work with stakeholders to reach consensus to protect environmental and economic interests of offshore wind projects in Lake Michigan. NYSERDA also suggests using a collaborative approach, which has been beneficial in U.S. East Coast offshore wind development.[321] Federally, updates would be required to the U.S. Army Corps of Engineers' current regulatory and legal frameworks (Section 10 of the Rivers and Harbors Act and Section 404 of the Clean Waters Act) that regulate lakebed use and permitting in the Great Lakes.[322]

Further examination of issues and policy recommendations related to Lake Michigan offshore wind energy development in state waters can be found in a 2009 report from the Great Lakes Wind Council.[323] The report outlines key recommendations for offshore wind in Michigan regarding mapping criteria, permitting, leasing, and public engagement.[324] The report found a small fraction of Michigan's Great Lakes could produce significant amounts of wind energy.[325] The council also provided recommendations on a legislative framework for bottomland (lakebed) leasing and permitting for offshore wind energy systems in Michigan's Great Lakes. One recommendation suggests, beyond site-specific data related to mapping criteria, permitting criteria should include specificity for the State to understand the risks to the public trust resources while also accounting for public benefits associated with a project.

In contrast in Illinois, as outlined in the Lake Michigan Wind Energy Act,[326] the scoring matrix does not offer insight into cost-benefits of siting areas for a potential project in Illinois waters. The Michigan report also recommends compensation received by the State for leasing bottomlands (the lakebed) through legislation via application fee, rent, and or royalties. Michigan Part 325 is the governing statute in Michigan established to protect the

[319] Commission, Great Lakes, Pebbles, Victoria, Hummer, John, & Haven, Celia. (2011) Best Practices for Sustainable WInd Energy Development in the Great Lakes Region and Beyond. United States. https://doi.org/10.2172/1032864

[320] GLC, 2011.

[321] New York State Energy Research and Development Authority (NYSERDA). 2022. "New York Bight Offshore Wind Farms: Collaborative Development of Strategies and Tools to Address Commercial Fishing Access," NYSERDA Report Number 22-24. Prepared by National Renewable Energy Laboratory, Responsible Offshore Development Alliance, and Global Marine Group, LLC. nyserda.ny.gov/publications

[322] Rivers and Harbors Act of 1899, Section 10. 33 U.S.C. § 403 (2000), Clean Water Act. 33 U.S.C. §1344 (2001)

[323] Michigan Great Lakes Wind Council. 2010. "Report of the Michigan Great Lakes Wind Council" Prepared by Mikinetics Consulting LLC, Public Sector Consultants Inc. https://www.baycounty-mi.gov/uploads/GLOWreportOct2010_with%20appendices.pdf

[324] (MGLWC, 2010)

[325] Kloosterman, S. (2015, February 11). Whatever happened to offshore wind energy? five years since lake Michigan wind turbines proposed. Michigan Live. Retrieved from https://www.mlive.com/news/muskegon/2015/02/whatever_happened_to_offshore.html.

[326] (20 ILCS 896/25),

public trust in Great Lakes bottomlands and waters.[327] Under previous statues, offshore wind development would not be permitted as permits may not be issued to a non-riparian.

A Wisconsin Public Service Commission exploratory committee published a report, *Harnessing Wisconsin's Energy Resources: An Initial Investigation Into Great Lakes Wind Development*,[328] which outlines the potential for offshore wind to meet Wisconsin's RPS. This in-depth report encompasses all mechanisms and exercises under Wisconsin law that could be applicable to offshore wind. The report concluded that further collaboration with the Great Lakes Commission to establish and develop a set of guidance and required studies, similar to BOEM's auctioning process, would be beneficial to all states with lakebed authority in the Great Lakes region.

There had been some legislative consideration on potential wind development in Illinois prior to the introduction of HB 2132. Illinois passed the Lake Michigan Wind Energy Act[329] in 2012, tasking the State's Lake Michigan Offshore Wind Energy Advisory Council to provide clarification regarding the State's authority to permit offshore wind development[330] and provide additional recommendations to further the sustainable and responsible development of the State's wind energy resources above Lake Michigan.

Further, the IDNR's Lake Michigan Offshore Wind Energy Advisory Report outlines the concept of the public trust doctrine, which is that "federal and state common law recognize the State of Illinois holds its public water resources, specifically including the water and the bed of Lake Michigan, in trust for the benefit of and the use by its citizens."[331] The report notes that the public trust doctrine determines whether and how offshore wind development occurs in Lake Michigan and what needs further guidance from the Illinois General Assembly. Recommendations from this report seek authorizing legislation from the legislature that clarifies the authority of the IDNR to develop a phased approach to leasing the bed of Lake Michigan for offshore wind energy development where it includes guidance on what an applicant must provide impact studies on.[332] Recommendations from the report ask that the legislature clarify IDNR authority on whether to determine which portions of the lakebed of Lake Michigan are available for lease.[333]

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[327] MCL 324.32501–32516

[328] Wisconsin Public Service Commission. 2009. Harnessing Wisconsin's Energy Resources: An Initial Investigation Into Great Lakes Wind Development. A Report to the Public Service Commission of Wisconsin. Docket 5-EI-144. https://apps.psc.wi.gov/ERF/ERFview/viewdoc.aspx?docid=106801

[329] 20 ILCS 896/5

[330] 20 ILCS 896/5(8)

[331] Illinois Department of Natural Resources (IDNR). 2012. "Lake Michigan Offshore Wind Energy Report". Prepared by the Illinois Department of Natural Resources, https://dnr.illinois.gov/content/dam/soi/en/web/dnr/documents/lmowefinalreport62012.pdf

[332] IDNR, 2012

[333] While developing the framework for lakebed leasing and permitting procedures is outside of the scope of this Policy Study, the Agency recognizes that resources that are held in trust for the public, such as Lake Michigan's lakebed, are to be safeguarded under the public trust doctrine. The three basic principles that apply to public trust doctrine considerations are established in *Lake Michigan Federation v. United States Army Corps of Engineers*, 742 F. Supp. 441 (1990). These three principles are: (1) courts should be critical of attempts by the State

iv) Incentives and Costs

(1) Production Tax Credit

The 2022 passage of the IRA spurred industry in the United States to meet the Biden administration's goals of 100% carbon-emissions-free electricity sector by 2035 and zero carbon emissions nationwide by 2050.[334] Relatedly, DOE has an ambitious goal to deploy 30 GW of new offshore wind energy by 2030.[335]

To support this goal, DOE's Loan Programs Office ("LPO") released a guide regarding $3 billion in funding opportunities through LPO's Title 17 Innovative Energy Loan Guarantee Program.[336] In January 2022, DOE issued a national strategy report outlining "priority areas" that can accelerate the sustainable development of offshore wind energy in the United States.[337] This strategy document outlines DOE's contributions to meet the challenges in deploying this quantity of wind, acknowledging the challenges associated with this growth. Issues that require further consideration for widespread offshore development include reducing the levelized cost of energy; expanding predictable leasing and permitting processes; developing the domestic supply chain; and expanding transmission. All of these challenges currently impede rapid offshore wind deployment in the United States.

The IRA extends and increases both investment tax credits ("ITC") and production tax credits ("PTC") through 2024 for wind projects that begin construction prior to January 1, 2025.[338] ITCs provide a credit against regular income tax otherwise due for the taxpayer. This is calculated as a percentage of investment in equipment and facilities made by the taxpayer. The PTC provides a credit against income tax otherwise due based on the amount of energy produced from a facility. The PTC is allowable only if the facility produces electricity while the investment credit is available, without needing output from the facility as long as it is energized.

To best maximize tax credits, available owners and developers of offshore wind energy facilities are likely to claim the ITC instead of the PTC; however, credit value is dependent on

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to surrender valuable public resources to a private entity; (2) the public trust is violated when the primary purpose of a legislative grant is to benefit a private interest; and (3) any attempt by the State to relinquish its power over a public resource should be invalidated under the doctrine.

334 The White House. (2021, April 22). FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies. Retrieved from https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/.

335 Energy Secretary Granholm Announces Ambitious New 30GW Offshore Wind Deployment Target by 2030. (2021, March 29). Retrieved from https://www.energy.gov/articles/energy-secretary-granholm-announces-ambitious-new-30gw-offshore-wind-deployment-target.

336 Department of Energy LPO, REEE. (n.d.). Renewable Energy an Efficient Energy, Loan Guarantees. Retrieved from https://www.energy.gov/sites/default/files/2021-03/DOE-LPO_Program%20Handout_T17-REEE-Offshore%20Wind_2021-03-26.pdf.

337 Marlay, R., Lefler, K., & Moreno, A. (2022, January). Offshore Wind Energy Strategies Report. https://www.energy.gov/sites/default/files/2022-01/offshore-wind-energy-strategies-report-january-2022.pdf

338 GovTrack.us. (2024). H.R. 5376 — 117th Congress: Inflation Reduction Act of 2022. Retrieved from https://www.govtrack.us/congress/bills/117/hr5376

construction start date and other factors. The ITC provides cash flow up-front at the start of the project, helping fund the development of a project. For a project commencing construction by December 31, 2024, the IRA expands and extends the ITC for up to 30% of the cost of installed equipment. This is subject to apprenticeship and prevailing wage requirements as outlined in the IRA.[339] This is significant for the offshore and distributed wind sectors, which are more capital-intensive and tend to benefit more from the up-front tax benefits than from the longer-term PTC.

Beyond extending the ITC and PTC for developers, the IRA also has provisions for credits of up to 10% for meeting domestic content thresholds[340] and locating facilities in fossil-fuel-powered communities or on brownfield sites.[341] These bonus credits can be combined with the ITC or PTC for qualifying projects. If a project meets the prevailing wage and apprenticeship requirements, and can successfully claim one or both bonus credits, a project could potentially claim up to 50% ITC.

In April 2023, the IRS issued Notice 2023-29 on what a qualified facility located in an energy community ("EC Project") is eligible for a credit.[342,343] As offshore wind projects are not in the boundary waters of a state, there was not a consensus on what should happen. In this Notice, the Internal Revenue Service ("IRS") and the U.S. Department of Treasury ("Treasury") indicated that "if an EC Project with offshore energy generation units has nameplate capacity but none of the EC Project's energy-generating units are in a census tract, metropolitan statistical areas ("MSA"), or non-metropolitan statistical areas ("non-MSA"), then the Nameplate Capacity Test for such EC Project is applied by attributing all the nameplate capacity of such EC Project to the land-based power conditioning equipment that conditions energy generated by the EC Project for transmission, distribution, or use and that is closest to the point of interconnection."[344] If a project's generating units are beyond a census tract, then the onshore substation that connects the project's generation output for transmission, distribution, or use and that is located nearest to the point of land-based interconnection *and* is located in an energy community, the taxpayer may attribute the nameplate capacity to that onshore substation. If they met the requirement, then the entity can claim the increased tax credit. In June 2023, the IRS issued Notice 2023-45,[345] which

[339] For more information on prevailing wage and apprenticeship under the Inflation Reduction Act please see the IRS's FAQ: Frequently asked questions about the prevailing wage and apprenticeship under the Inflation Reduction Act | Internal Revenue Service (irs.gov)

[340]For more information see: http://www.energy.gov/infrastructure/qualifying-advanced-energy-project-credit-48c-program :http://www.irs.gov/pub/irs-drop/n-23-38.pdf

[341] http://www.irs.gov/pub/irs-drop/n-23-29.pdf

[342] U.S. Department of the Treasury. Internal Revenue Service. (2023). Notice 2023-29, retrieved from https://www.irs.gov/pub/irs-drop/n-23-29.pdf

[343] Energy communities are a federal designation for prioritizing communities impacted by coal closures that was created through the Inflation Reduction Act. They are not the same Equity Investment Eligible Communities or Environmental Justice Communities as used in Illinois. For more information on energy communities including an online mapping tool, see: https://energycommunities.gov/

[344] IRS, No. 2023-29, 2023

[345] U.S. Department of the Treasury. Internal Revenue Service. (2023). Notice 2023-45, retrieved from https://www.irs.gov/pub/irs-drop/n-23-45.pdf

updates Notice 2023-29,[346] describing its determination on what constitutes an energy community for the PTC and ITC. This did not impact the offshore wind Nameplate Capacity Attribution Rule,[347] however it did alter the Prior Modification of Special Rule for Beginning of Construction.[348]

Many coastal states have recently filed comments regarding the IRA's Energy Community Bonus Credit for Offshore Wind (Notice 2023-29). The Connecticut Department of Energy and Environmental Protection, Maryland Energy Administration, Massachusetts Executive Office of Energy and Environmental Affairs, New Jersey Board of Public Utilities, NYSERDA, and Rhode Island Office of Energy Resources asked the Treasury and the IRS to broaden their guidance on availability and qualification for the ITC and PTC.[349] States' comments provided concerns that, without further guidance from the Treasury or IRS, current guidance is insufficient to achieve offshore wind deployment outcomes due to lack of clarity. In the absence of improved guidance, developers will assume that tax credits will not be accessible, leading to higher project costs reflected in higher state procurement costs. This current uncertainty is holding back investment and long-term growth in offshore wind development.

The IRA can address supply side issues and reduce impacts from inflation. For qualifying projects, each bonus tax credit can help offset 10% of the costs of a new project, providing up to 40% in cost support when combined with the 30% base ITC or PTC.[350] If developers can maximize these clean energy tax credits, the Treasury and the IRS can incubate a stronger domestic offshore wind industry, reducing energy costs, and enhancing U.S. manufacturing production and jobs.

(2) Project Costs and Project Economics

Given the large investment cost for the construction of floating or fixed-base turbines needed for offshore wind development in Lake Michigan, absent policy-based financial incentives, projects would need increased electricity prices to recoup costs solely through the generation of electricity. Electricity rates are relatively low in Illinois compared to other Midwestern states and the East Coast, where offshore wind development has been the

[346] N-2023-29 (irs.gov)

[347] If a qualified Offshore Wind project (500W nameplate capacity) is located on the outer continental shelf. Then all energy generating units are not in a census tract, MSA, or non-MSA. The onshore substation that the Project's uses as the nearest to the point of land-based interconnection. A Taxpayer may attribute the Project's nameplate capacity to that onshore substation under the Nameplate Capacity Attribution Test, if in an EC the Taxpayer can claim that bonus adder as well. (IRS N-2023-45, 2023)

[348] If a taxpayer begins construction of an EC (energy Community) Project on or after January 1, 2023, in a location that is an energy community as of the beginning of construction (BOC) date, the location will continue to be considered an energy community for the duration of the credit period, applicable for §§ 45, 45Y, 48, and 48E of the Internal Revenue Code (IRS N-2023-45, 2023).

[349] Offshore Wind Procuring States' Comments on the Inflation Reduction Act of 2022's Energy Community Bonus Credit for Offshore Wind (https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Offshore-Wind/Resource-Library/Multistate-comments-2022-IRA-energy-community-credit.pdf)

[350] Horwath, J. (2023, August 15). Ira at 1: U.S. Boost to offshore wind imperiled by struggling projects. S&P Global Homepage. IRA at 1: US boost to offshore wind imperiled by struggling projects | S&P Global Market Intelligence (spglobal.com)

greatest.[351] Illinois and much of the Midwest has significant renewable energy provided by land-based wind projects compared to coastal states, specifically the East Coast.[352] One factor that will be advantageous to offshore wind developers and will lower costs compared to ocean-based offshore wind development is the jurisdiction of the Great Lakes. Individual states will have the ability to license offshore wind energy projects in their respective state waters (in state jurisdiction), unlike ocean-based offshore wind developments, which must go through federal BOEM permitting processes.[353]

In comments to the Treasury and the IRS, Atlantic states are concerned that consecutive price reductions in new offshore wind contracts between 2016 and 2022 has reversed since late 2022. This has had negative impacts on recent procurements and many states are seeing project attrition from those under old contracts (2016-2022) as discussed in Section 6)b)ii)(1) below. Further, Atlantic states have brought concerns around the slow release of guidance for IRA funding. These concerns include that offshore wind costs for early adopting are higher than costs will be in the future, after the U.S. offshore wind industry matures. Through the ITC and PTC, the federal government is an essential partner in lowering the initial costs to the states' ratepayers and enabling the early procurements needed to grow a domestic offshore wind industry.[354] For a project to reach economies of scale, investing IRA funding into an early buildout of the Great Lakes offshore wind supply chain and investing in a trained workforce will have better outcomes in future offshore wind solicitations and procurements. Current procurements will lower the costs of future offshore wind deployments, not just to coastal states, but also to others as well as their projects face higher development costs given the slower supply chain build out.

(3) Other Federal Funding

Beyond the ITC and PTC, there are other federal incentives available for offshore wind development. DOE has allocated over $300 million to competitively selected offshore wind research, development, and demonstration projects. This is to further technology advancement research for offshore wind and bring down development costs for commercially developed offshore wind projects. DOE's Wind Energy Technologies Office

[351] Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, The East North Central region has an average residential electricity price in September 2023 of 16.00 (Cents per Kilowatt-hour), whereas New England and the MidAtlantic for the same month have prices of 27.41 and 20.11 (Cents per Kilowatt-hour) respectably. Illinois had an average price of 14.79 (Cents per Kilowatt-hour) during this time. Electric Power Monthly – U.S. Energy Information Administration (EIA). (n.d.). https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_5_06_a

[352] See Hoen, B.D., Diffendorfer, J.E., Rand, J.T., Kramer, L.A., Garrity, C.P., and Hunt, H.E., 2018, United States Wind Turbine Database v6.1 (November 28, 2023): U.S. Geological Survey, American Clean Power Association, and Lawrence Berkeley National Laboratory data release, https://doi.org/10.5066/F7TX3DN0.

[353] Bureau of Ocean Energy Management (BOEM). (n.d.). Renewable energy on the Outer Continental Shelf – Bureau of Ocean … https://www.boem.gov/sites/default/files/uploadedFiles/Fact%20Sheet%20BOEM%20Renewable%20Energy.pdf

[354] Connecticut Department of Energy and Environmental Protection, Maryland Energy Administration, Massachusetts Executive Office of Energy and Environmental Affairs, New Jersey Board of Public Utilities, New York State Energy Research and Development Authority, & Rhode Island Office of Energy Resources. (2023, September 27). Offshore Wind Procuring States' Comments on the Inflation Reduction Act of 2022's Energy Community Bonus Credit for Offshore Wind (Notice 2023-29). Retrieved from https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Offshore-Wind/Resource-Library/Multistate-comments-2022-IRA-energy-community-credit.pdf.

("WETO") has set up a $41 million national offshore wind Research and Development Consortium, administered by NYSERDA, to address near-term needs to support the development of the U.S. offshore wind industry. These near-term needs include holding solicitations to conduct research on wind plant technology advancement; wind resource and physical site characterization; installation, operations, and maintenance; and supply chain technology solutions.[355] The Consortium provides as roadmap of example projects that it could approve from a solicitation, such as creating geospatial ice models that can predict ice ridge formation and magnitude, or ice models that estimate loading. The IRA provides the U.S. Environmental Protection Agency ("EPA") with $3 billion to fund zero-emission port equipment and infrastructure as well as climate and air quality planning at U.S. ports.[356] Notice of Funding Opportunity ("NOFO") has not been released yet. EPA anticipates disbursing this Clean Ports Program funds through two sub-programs: Climate and Air Quality Planning Sub-Program (up to $300M)[357] Zero-Emission Technology Deployment Sub-Program (up to $2.6 billion).[358,359] The U.S. Department of Transportation's Maritime Administration ("MARAD") has put out NOFO for $662 million in Federal Fiscal Year ("FY") 2023, for funding for MARAD's Port Infrastructure Development Program ("PIDP") which closed FY 2023 applications in April 2023.[360] From the Bipartisan Infrastructure Law ("BIL"), it designates $450 million annually for the next five years for PIDP applicants. This will allow improvements to port facilities on coasts, rivers, and the Great Lakes. Improvement projects can fall into one of four categories: loading and unloading of goods at a port; movement of goods into, out of, around, or within a port; resilience;[361] and environmental and emissions mitigation measures.[362] If a port qualifies under one of these improvement categories, they can apply to receive funding to support offshore wind development.

[355] National Offshore Wind Research and Development Consortium. (2023, April). Research and Development Roadmap–4 - National Offshore Wind. https://nationaloffshorewind.org/wp-content/uploads/NOWRDC-Research-Development-Roadmap-4.0.pdf

[356] H.R.5376

[357] This can include activities such as Emissions inventory and accounting practices; Stakeholder collaboration and communication, with a focus on near-port communities; Strategy analysis and goal-setting; and Resiliency planning

[358] This includes activities such as Cargo handling equipment; Drayage trucks; Locomotives; Harbor craft; Charging and other fueling infrastructure for zero emission port equipment, including shore power for marine vessels.

[359] Macedonia, J., Núñez, A., Simon, K., & Moltzen, M. (n.d.). EPA Clean Ports Program – First Look!, 31, October, 2023, Retrieved from https://www.epa.gov/system/files/documents/2023-11/clean-ports-prog-update-webinar-2023-10-31.pdf.

[360] USDOT Announces More Than $660 Million Available Through the Port Infrastructure Development Program. (2023, February 8). Retrieved from https://www.transportation.gov/briefing-room/usdot-announces-more-660-million-available-through-port-infrastructure-development#:~:text=WASHINGTON%20%2D%20The%20U.S.%20Department%20of,Infrastructure%20Development%20Program%20(PIDP).

[361] Such as addressing flooding, and/or extreme weather events, etc.

[362] Such as improvement projects to reduce or eliminate port-related pollutants and/or greenhouse gas emissions.

b) Offshore Wind Case studies in Other U.S. States

i) States

Atlantic coast states have seen significant offshore wind policy development and account for most of the offshore wind project capacity under development.[363] Not all states have developed offshore wind policy in the same manner. Some states have aspirational planning goals that may not require various agencies to take any direct action, whereas other states have procurement mandates that require state agencies and/or utilities to develop and execute offshore wind energy solicitations. Thirteen states have set offshore wind planning goals or procurement mandates. DOE's 2023 Offshore Wind Market Report shows an overview of all current state planning goals and mandated state procurements by year (See Table 6-1). DOE also calculates that all thirteen states with set planning goals and/or procurement mandates total up to 112,286 MW of offshore wind capacity by 2050, with procurement mandates from various states equating to 42,730 MW of capacity by 2040.[364]

Table 6-1: Offshore Wind Goals and Procurements[365]

State	Planning Goal - Capacity (MW)	Planning Goal - Year	Offtake Contracts Awarded (MW)	Awarded Projects (MW)	Ongoing Procurement (MW)	Supporting Policies and Documents
Maine	156	2030	12	Aqua Ventus (12)		*Maine Wind Energy Development Assessment (2012)*
Massachusetts	23,000	2050	3,236	Vineyard Wind 1 (800) SouthCoast Wind 1 (804) South Coast Wind 2 (400) New England Wind (1,232)	400–3,600 (closes 1/31/2024)	*Act to Promote Energy Diversity (2016)* *Act to Advance Clean Energy (2018)* *Massachusetts 2050 Decarbonization Roadmap (2020)* *Act Creating a Next Generation Roadmap for Massachusetts Climate Policy (2021)*
Rhode Island	1,430	2030	430	Block Island Wind Farm (30) Revolution Wind (400)	600–1,000 (closed 3/13/23)	*Request for Proposals for Long-Term Contracts for Offshore Wind Energy (2022)*
Connecticut	2,000	2030	1,104	Revolution Wind (304) Park City Wind (800)	Draft request for proposal for 1,196	*Public Act No. 19-71 (2019)*
New York	20,000	2050	4,362	South Fork Wind (132) Empire Wind 1 (816) Sunrise Wind 1 (924) ~~Empire Wind 2 (1,260)~~ ~~Beacon Wind 1 (1,230)~~ Attentive Energy One (1,404 MW) Community Offshore Wind (1,314 MW) Excelsior Wind (1,314 MW)	1,000–2,000 (closed 1/26/2023)	*Case 18-E-0071 (2018)* *Climate Leadership & Community Protection Act (2019)* *New York State Climate Action Council Scoping Plan (2022)*
New Jersey	11,000	2040	3,758	~~Ocean Wind 1 (1,100)~~ ~~Ocean Wind 2 (1,148)~~ Atlantic Shores Offshore Wind South (Project 1) (1,510) Leading Light Wind (2,400) Attentive Energy Two (1,342)	1,200–4,000 (closes 6/23/23)	*Offshore Wind Economic Development Act (2010)* *Executive Order 8 (2018)* *Executive Order 92 (2019)* *Executive Order 307 (2022)*
Maryland	8,500	2031	2,045	Skipjack 1 (120) MarWin (270) Momentum Wind (808) Skipjack 2 (846)		*Maryland Offshore Wind Energy Act (2013)* *Clean Energy Jobs Act (2019)* *Promoting Offshore Wind Energy Resource Act (2023)*
Virginia	5,200	2034	2,599	CVOW Pilot (12) CVOW Commercial (2,587)		*Virginia Clean Economy Act (2021)*
North Carolina	8,000	2040	-			*Executive Order 218 (2021)*
California	25,000	2045	-			*AB 525 (2021)* *Offshore Wind Energy Development off the California Coast: Maximum Feasible Capacity and Megawatt Planning Goals for 2030 and 2045 (2022)*
Ohio	-	-	21	~~LEEDCo (21)~~		*None*
Louisiana	5,000	2035	-			*Louisiana Action Plan (2022)*
Oregon	3,000	2030	-			*HB 3375 (2021)*
Total	**112,286**	**2050**	**17,567**			

[363] New Jersey, New York, and Massachusetts Account for Over 50% of the Capacity in the U.S. Project Pipeline (Musial et al., 2023).

[364] Musial et. al, 2023

[365] Projects that are strike through indicate projects that previously received awards and have since cancelled their projects.

(1) New York

New York's 2019 Climate Leadership and Community Protection Act[366] requires the State to achieve a 100% carbon free electricity system by 2040 and to reduce greenhouse gas emissions 85% below 1990 levels by 2050. Within this law are mandates that at least 70% of New York's electricity come from renewable energy sources by 2030 and 9,000 megawatts of offshore wind energy by 2035.[367] NYSERDA is the State authority charged with implementing New York's offshore wind energy goals. In 2015, NYSERDA published its first report on *Advancing the Environmentally Responsible Development of Offshore Wind Energy in New York State.*[368] Anticipating the growing industry of offshore wind, in that report, NYSERDA brought together State and federal regulators to participate in a process to help define the goals of environmental assessments for offshore wind and wildlife. At the time there was little precedent for permitting, leading to questions and uncertainties about the environmental permitting process for offshore wind. Additionally, in 2018, NYSERDA issued New York State's first competitive solicitation for at least 800 megawatts of offshore wind energy, awarding contracts to two projects.[369] Since then, NYSERDA has held three additional competitive solicitations.

NYSERDA's 2018 Offshore Wind Policy Options Paper lays out several dynamic procurement pricing mechanisms to ensure that offshore wind can be supported through the State's procurements.[370] One option is a fixed price REC approach, through which NYSERDA issues a Request for Proposals to procure RECs from offshore wind projects through long-term contracts. The offshore wind projects offer competitive bids at a fixed $/megawatt-hour (MWh) price to NYSERDA. NYSERDA then executes contracts similar to their REC Tier 1 solicitations.[371] Although this provides revenue certainty for projects, this model does not provide a long-term electricity price hedge and project developers would be allowed to seek other private agreements for hedges. The benefit of a fixed price REC procurement structure is that it is implementable and is the standard model in many markets. Concurrent with other reports on offshore wind development, NYSERDA notes that the limitation of this model "is that it leaves commodity price risk with the offshore wind project, with the elevated risk to

[366] NY State Senate Bill 2019-S6599 (nysenate.gov)

[367] Governor's Office State of New York (2019, July 18) Governor Cuomo Executes the Nation's Largest Offshore Wind Agreement and Signs Historic Climate Leadership and Community Protection Act | Governor Andrew M. Cuomo (archive.org)

[368] NYSERDA (June 2015) Advancing the Environmentally Responsible Development of Offshore Wind Energy in New York State: A Regulatory Review and Stakeholder Perceptions https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Research/Environmental/Advancing-Environmental-Response-Development-Off-Shore-Wind-New-York.pdf

[369] New York State Energy Research and Development Authority (NYSERDA). (2018). Offshore wind: 2018 Solicitation. https://www.nyserda.ny.gov/All-Programs/Offshore-Wind/Focus-Areas/Offshore-Wind-Solicitations/2018-Solicitation

[370] NYSERDA, 2020. https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Research/Biomass-SolarWind/Master-Plan/Offshore-Wind-Policy-Options-Paper.pdf.

[371] NYSERDA, 2020 https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Research/Biomass-Solar-Wind/Master-Plan/Offshore-Wind-Policy-Options-Paper.pdf

the developer leading to increased cost of capital for offshore wind projects and resultant higher offshore wind REC prices than alternatives which hedge commodity revenues."[372]

NYSERDA found that designing a procurement structure that provides a hedge against electricity price risk will have a significant reduction in project finance costs, thus impacting premium payments and ratepayers.[373] NYSERDA asserts that that one mechanism to provide this hedging certainty is a bundled power purchase agreement ("PPA"), which would fully hedge a revenue stream for the value of power and RECs, diminishing risk in revenue uncertainty. Unlike a fixed price REC, a bundled PPA would submit bids as the "all-in" revenue amount per MWh required by the project giving the strike price.

Further, NYSERDA's Offshore Renewable Energy Credit ("OREC") contract structure delivers an agreed-upon number of RECs for offshore wind projects. Remaining energy and capacity would be sold by the offshore wind project and report the sale revenues to NYSERDA. NYSERDA would then deduct from the strike price the actual revenues received by the offshore wind generator from selling energy and capacity. This structure is similar to the IPA's current Indexed REC procurement model used for utility-scale wind and solar projects. Instead of a traditional procurement structure, New York took a unique approach to offshore wind procurements. NYSERDA decided on a hybrid bid approach for projects participating in its procurement. Each project is required to include two bids, one for a fixed OREC price ("Fixed OREC") and one for an adjustable OREC price ("Index OREC"). NYSERDA then awards a contract for either contract structure, noting that if an Index OREC is selected, there is reversion in the contract specifying conditions that may trigger the contract to default to a Fixed OREC.[374]

Additionally, NYSERDA has a library of technical studies to support the State's offshore wind goals. New York is also making a $500 million investment proposal for offshore wind ports, manufacturing, and supply chain infrastructure.[375] NYSERDA is also releasing funding in three phases to help attract and catalyze additional private funds for further development of the industry. The first phase of this funding was made available as part of the State's third offshore wind solicitation (ORECRFP22-1) issued in 2022.[376] NYSERDA's Offshore Wind

[372] NYSERDA Offshore Wind Policy Paper, 2018

[373] NYSERDA. 2015. "Large-Scale Renewable Energy Development in New York: Options and Assessment" NYSERDA Report 15-12. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={26BD68A2-48DA-4FE2-87B1-687BEC1C629D}; DPS. 2016. "Clean Energy Standard White Paper – Cost Study."

[374] Maryland, North Carolina, and Virginia (2020, October 29) MOU To Create the Southeast and Mid-Atlantic Regional Transformative Partnership for Offshore Wind Energy Resources (SMART-POWER) https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Offshore-Wind/NYSERDA-OSW-ORECRFP22-1-Proposers-Conference_Presentation-Slides.pdf

[375] Governor's Office State of New York (2022, January 5) Governor Hochul Announces Nation-Leading $500 Million Investment in Offshore Wind | Governor Kathy Hochul (ny.gov)

[376] Governor's Office State of New York (2022, July 27) Governor Hochul Announces New York's Third Offshore Wind Solicitation to Accelerate Clean Energy Development https://www.governor.ny.gov/news/governor-hochul-announces-new-yorks-third-offshore-wind-solicitation-accelerate-clean-energy

Policy Options Paper[377] explored transmission and interconnection strategies directing radial and backbone.[378] NYSERDA continues to actively study transmission and other interconnection strategies for different areas of shoreline to best support offshore wind. Finally, NYSERDA has held four offshore wind procurement solicitation events since 2018. While New York currently has over 8,000 MW from three solicitations events under contract,[379] there are current contract default issues. This is discussed more in Section (6)b)ii)(1) below.

(2) Maryland

Offshore wind development off Maryland's coast was spurred when the State enacted the Maryland Offshore Wind Energy Act of 2013.[380] The Act altered Maryland's RPS goal where 25% of electric consumption in the State is to come from renewable energy by 2020, with an offshore wind technology carve-out not to exceed 2.5 percent (about 500 MW) of the overall RPS. Projects from this initial target are known as Round 1 projects. Maryland passed the Clean Energy Jobs Act ("MCEJA") in 2019, which revised the State's RPS to 50 percent by 2030.[381] MCEJA also removed its ceiling cap on offshore wind development towards RPS goals to require an additional 1,200 MW of projects through three new offshore wind procurement rounds. These are known as Round 2 targets.

Maryland's Market Offshore Wind Renewable Energy Credit ("OREC") is the payment structure for its procurements.[382] The Maryland OREC and NYSERDA OREC both provide revenue certainty for the developer by locking in the value of energy in the settled upon strike price. The Maryland Public Service Commission ("PSC") has approved a total of 2,022.5 MW of offshore wind capacity through the Round 1 and Round 2 OREC procurements.[383] Maryland estimates that the projects accepted are anticipated to create more than 12,000 direct full time equivalent ("FTE") jobs during the development and constructions phase and 3,000 direct long-term FTE jobs during the operations and maintenance of the projects' lifetime.[384] Project developers have committed to small businesses and minority-, women-,

[377] New York State Energy Research and Development Authority. 2018. Offshore Wind Policy Options Paper. https://www.nyserda.ny.gov/-/media/Files/Publications/Research/Biomass-SolarWind/Master-Plan/Offshore-Wind-Policy-Options-Paper.pdf

[378] Direct radial transmission facilities are developed, sized, and constructed to support one offshore wind facility. Backbone transmission facilities are expandable to accommodate an initial facility as well as facilities built in the future (Offshore Wind Policy Options Paper, 2018).

[379] NYSERDA (2023) New York Offshore Wind Projects

[380] 2013 Regular Session - House Bill 226 Chapter (maryland.gov)

[381] 2019 Regular Session - Senate Bill 516 Chapter (maryland.gov)

[382] 2013 Regular Session - House Bill 226 Chapter (maryland.gov)

[383] PSC Order No 88192, Order No 90011

[384] Offshore Wind (maryland.gov)

and veteran-owned business participation goals.[385] For example, the developer U.S. Wind commits to 15 percent of labor for its project in Maryland.

The Maryland Energy Administration also has funding opportunities available to businesses to support the establishing an offshore wind supply chain and an experienced workforce. The Maryland Offshore Wind Supply Chain Investment Program provides non-competitive grants to support new or existing businesses entering the offshore wind supply chain in Maryland.[386] The Maryland Offshore Wind Workforce Training and Education Program is a competitive grant for new or existing workforce training centers and academic institutions to expand to support the State's offshore wind workforce training and education efforts.[387] Further, to support offshore wind, the governors of Maryland, North Carolina, and Virginia have created the Southeast and Mid-Atlantic Regional Transformative Partnership for Offshore Wind Energy Resources ("SMART-POWER").[388] SMART-POWER's memorandum of understanding ("MOU") provides that it is a collaboration to provide a framework for the three states to promote, develop, and expand offshore wind and the accompanying industry supply chains and workforces. One goal of which is for the three states to align state regulatory requirements related to offshore wind construction and installation of offshore wind projects to reduce administrative burdens.

(3) Rhode Island

Rhode Island saw the U.S.'s first commercial offshore wind project with the 30 MW Block Island Wind Farm commissioned in 2016.[389] Through Executive Order 20-01 *Advancing a 100% Renewable Energy Future for Rhode Island by 2030*, Rhode Island seeks to meet total electricity demand with renewable energy by 2030.[390] The Rhode Island Office of Energy Resources ("OER") conducted an economic and energy market analysis and developed policy and programmatic pathways to meet this goal.[391] This report estimated that there was 900-1,100 MW of offshore wind needed to fill the entire 2030 renewable energy gap. In October 2023, Rhode Island, Massachusetts, and Connecticut announced New England's first offshore wind joint multi-state coordination MOU for a potential coordinated procurement of

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385 Order No. 881–2 - Case No. 94–1 - Offshore Wind (maryland.gov)

386 Maryland Energy Administration (2023) Maryland Offshore Wind Supply Chain Investment Program Fiscal Year 2024 https://energy.maryland.gov/SiteAssets/Pages/Info/renewable/supplychaininvestment/FY24%20SCIP%20Overview.docx.pdf

387 Maryland Energy Administration (2023) Maryland Offshore Wind Workforce Training & Education Program Fiscal Year 2024 https://energy.maryland.gov/SiteAssets/Pages/Info/renewable/offshorewindworkforce/FY24%20WF%20Program%20Overview%20Doc%20%284%29.pdf

388 Maryland, North Carolina, and Virginia (2020, October 29) MOU To Create the Southeast and Mid-Atlantic Regional Transformative Partnership for Offshore Wind Energy Resources (SMART-POWER) Microsoft Wo–d - SMART POWER MOU_FINAL.docx (nc.gov)

389 "Offshore Wind Farm Raises Hopes of U.S. Clean Energy Back"rs". *The New York Times*. 24 July 2015. Archived from the original on 27 January 2017. Retrieved 1 March 2017.

390 Rhode Island Office of Energy Resources (2020, December) The Road to 100% Renewable Electricity; Executive Order 20-01 | Governor's Office, State of Rhode Island (ri.gov)

391 Rhode Island Office of Energy Resources (2020, December) The Road to 100% Renewable Electricity energy.ri.gov/sites/g/files/xkgbur741/files/documents/renewable/The-Road-to-100-Percent-Renewable-Electricity---Brattle-04Feb2021.pdf

offshore wind as each state solicits offshore wind energy generation through their respective state procurements.[392] For the joint MOU, the three states are having developers submit multi-state offshore wind project proposals through their respective offshore wind procurements for selection in 2024, based on interconnection location.[393]

Previously, Rhode Island Energy rejected a proposal it received from a procurement in 2022.[394] Rhode Island Energy chose not to move forward on a contract for Revolution 2 (884 MW) due to affordability concerns.[395,396]

(4) Massachusetts

The Massachusetts Clean Energy Center ("MassCEC") anticipates that offshore wind will be the State's largest source of clean energy and will help the Commonwealth meet its greenhouse gas emission reduction mandate.[397] Additionally, the 2016 bill titled, *An Act Relative to Energy Diversity*, requires Massachusetts utility companies to procure 1,600 megawatts (MW) of cost-effective offshore wind energy by 2027.[398] The first RFP by the utilities took place in June 2017.[399] Massachusetts has held three procurements with a fourth solicitation ongoing as of publication of this Policy Study.[400] The current RFP process seeks 3,600 MW of new offshore wind generation, which is roughly 25% of the State's annual electricity demand.[401] Massachusetts currently has about 4,000 MW under contract from the previous three RFPs.

Massachusetts uses a PPA structure where the distribution utility is the main driver of the contract, the offshore wind generator sells energy and RECs to the distribution utility, who sells excess energy into ISO-NE.[402] The RECs from the offshore wind generator are transferred to the distribution utility through the PPA, where they are then sold bilaterally

392 MA-RI-CT Offshore Wind Procurement Collaboration Memorandum of Understanding– -- Final 10-3-23 CEM Sig[45].pdf

393 MA-RI-CT Offshore Wind Procurement Collaboration Memorandum of Understanding– -- Final 10-3-23 CEM Sig[45].pdf

394 Rhode Island Office of Energy Resources. (2022, July 6). Governor McKee Signs Legislation Requiring Offshore Wind Procurement for 600 to 1,000 Megawatts | Rhode Island Office of Energy Resources

395 Sherman, E. (2023, July 19). RI Energy rejects plan for nearly 1000MW offshore wind project. WPRI.com. https://www.wpri.com/target-12/ri-energy-rejects-plan-for-100mw-offshore-wind-project/

396 Rhode Island Energy, "Rhode Island Energy not moving forward on sole bid received in most recent offshore wind solicitation" (July 18, 2023) (news release), https://news.pplweb.com/news-releases?item=137899.

397 Massachusetts 2050 Decarbonization Roadmap webinar slides, 1/15/21, MA Decarbonization Roadmap | Mass.gov

398 Bill H.4568 (malegislature.gov)

399 Pursuant to Section 83C of Chapter 169 of the Acts of 2008 Session L–w - Acts of 2008 Chapter 169 (malegislature.gov)

400 Healey-Driscoll Administration Files Historic Draft RFP for Massachusetts' Fourth Offshore Wind Solicitation. (2023, May 2). Massachusetts Government . Retrieved from https://www.mass.gov/news/healey-driscoll-administration-files-historic-draft-rfp-for-massachusetts-fourth-offshore-wind-solicitation.

401 Healey-Driscoll, 2023

402 Beiter, Philipp, Jenny Heeter, Paul Spitsen, David Riley. 2020. Comparing Offshore Wind Energy Procurement and Project Revenue Sources Across U.S. States. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5000-76079. https://www.nrel.gov/docs/fy20osti/76079.pdf.

to various electricity suppliers, who retire RECs to meet their state-mandated RPS requirement.

Massachusetts is also investing heavily in port infrastructure. MassCEC, through its Offshore Wind Ports Infrastructure Investment Challenge, awarded around $180 million in competitive grants in 2022 to develop offshore wind port assets Massachusetts.[403]

(5) New Jersey

New Jersey is the first state to enact offshore wind procurement legislation, via its Offshore Wind Economic Development Act in 2010.[404] The Act directed the State's Board of Public Utilities to create an offshore RECs ("ORECs") structure so that offshore wind projects could be compensated for their environmental attributes of generation and meet the State's target of procuring 1,100 MW of offshore wind energy off its coast.[405] These OREC requirements were finalized in 2018 through an Executive Order,[406] and the New Jersey legislature codified a procurement goal of 3,500 MW by 2030. This goal was expanded in 2020 to 7,500 MW by 2035.[407,408] In September 2022, New Jersey Governor Murphy signed Executive Order No. 307, further increasing the State's offshore wind energy generation goal to 11,000 MW by 2040.[409]

New Jersey's OREC structure has many overlaps with Maryland's OREC structure. For example, under OREC's structure, offshore wind generators sell electricity into PJM and directly receive the revenues from the electricity which then is returned to ratepayers via the distribution utility.[410] New Jersey has five offshore wind solicitations planned through 2028, with three events having occurred.[411] The first three solicitations brought a combined total of 7,500 MW to the State's total planned capacity.[412] New Jersey's fourth solicitation has a target to launch in early 2024 and project awards are expected in early 2025.[413]

New Jersey is also investing in port manufacturing facilities to support offshore wind development. The New Jersey Economic Development Authority is developing the New

[403] Niforos, Kathryn. 2022. "Baker-Polito Administration Announces $180M in Funding Through the Offshore Wind Ports Infrastructure Investment Challenge and Administration Releases the 2022 Clean Energy Industry Report." Massachusetts Clean Energy Center. https://www.masscec.com/press/baker-polito-administration-announces-180m-funding-throughoffshore-wind-ports-infrastructure

[404] New Jersey Legislature. 2010. Offshore Wind Economic Development Act. https://www.njleg.state.nj.us/2010/Bills/AL10/57_.PDF.

[405] New Jersey Legislature, 2010

[406] Governor Philip D. Murphy. 2018. Executive Order No. 8. https://nj.gov/infobank/eo/056murphy/pdf/EO-8.pdf.

[407] Governor Philip D. Murphy. 2020. Executive Order No. 92. https://nj.gov/infobank/eo/056murphy/pdf/EO-92.pdf

[408] New Jersey Legislature. 2018. Offshore Wind Economic Development Act. NJ A3723. https://legiscan.com/NJ/text/A3723/2018.

[409] Microsoft Word - EO-307 (nj.gov)

[410] NREL, 2020

[411] Murphy, 2020

[412] 6-21-19-8D.PDF (njcleanenergy.com) , OSWFactSheets_Final_630.pdf (nj.gov)

[413] State of New Jersey, Governor Philip D. Murphy, https://www.nj.gov/bpu/newsroom/2023/approved/20231129.html

Jersey Wind Port.[414] The Wind Port is located in Lower Alloways Creek, New Jersey, and once completed, is intended to support offshore wind marshalling and activities. The port also has potential for additional expansions to include co-located offshore wind manufacturing activities, and has a potentially developable footprint of over 200 acres. Any potential expansion beyond marshalling activities would be dependent on market demand as well as other factors.

The Wind Port can be home to multiple manufacturing facilities that will build the necessary components for offshore wind turbines. It is also strategically situated for component staging, final assembly, and transport (collectively known as marshalling). The New Jersey Economic Development Authority is leading the development of the project on behalf of the State, working alongside key departments and state agencies such as the Governor's Office, the Department of Treasury, the Department of Transportation, and the Board.

ii) Successes and Challenges

(1) Recent Contract Default Issues

There have been increased challenges offshore wind development since 2022. DOE reports that supply chain constraints, high inflation, and rising interest rates have resulted in significant project cost increases of 11%–30% during 2022.[416] Current supply chain issues are seeing higher costs which developers are trying to pass on to states' ratepayers due to developers wanting to recoup their costs to finance and bring offshore wind to energization. Without significant alleviation of inflation or supply chain issues, states will be forced to reject projects or allow previously procured projects to renegotiate.

Further, many states are concerned that inflationary pressures, lingering supply chain disruptions from the COVID-19 pandemic, and increased competition for labor, supplies, and financing from European nations seeking new clean energy projects to replace fossil fuel imports from Russia will decrease interest in project development in the U.S. By September 2023, economic pressures from supply chain constraints, inflation, and high interest rates have attributed to approximately 2.4 GW of announced project cancellations from previously procured offshore wind project contracts across the U.S.[417] Recent offshore wind procurement events in the U.S. have also been unsuccessful in filling target amounts.[418]

[414] New Jersey Wind Port (nj.gov)

[415] New Jersey Wind Port (nj.gov)

[416] DOE, 2023

[417] "SouthCoast Wind joins Commonwealth in scraping power contracts," *The Salem News* (June 6, 2023), https://www.salemnews.com/news/southcoast-wind-joins-commonwealth-in-scraping-power-contracts /article_0a06a318-04a4-11ee-80d8-4f03ada52794.html; McDermott, J., Daley, M., Hill, M., & Catalini, M. (2023, November 4). Offshore wind projects face economic storm. cancellations jeopardize biden clean energy goals. Associated Press . Retrieved from https://apnews.com/article/offshore-wind-orsted-cancellation-biden-new-jersey-3f2ff7c9832210ce862f6e7179fae439.

[418] Rhode Island Energy, "Rhode Island Energy not moving forward on sole bid received in most recent offshore wind solicitation" (July 18, 2023) (news release), https://news.pplweb.com/news-releases?item=137899 , Results Of Gulf Of Mexico Offshore Wind Auction & Recent U.S. Offshore Wind Update–. - Conventus Law

New York is presently in contract disputes with Orsted, Equinor, and BP over requests for increasing contract prices on formerly executed contracts.[419] The New York Public Service Commission found that amending contracts would result in increases of as much as 6.7% on residential utility customers' monthly bills.[420]

Until recently, allocation events in the United Kingdom ("UK") have successfully facilitated large amounts renewable deployment.[421] In 2022, the most recent allocation (Round 4) results saw nearly 11 GW of new renewable projects, simultaneously striking record low prices for offshore wind, which cleared at £37.35 per MWh (2012 prices).[422] In the UK, contracts utilize a Contract for Differences ("CfD") model. Differing from Maryland's OREC structure, the UK's CfD's commodity revenue amounts are derived from an index or composite of indices. This means the generator does not need to provide actual sales revenue data.

The most recent procurement conducted by the UK in late 2023 (Round 5 allocation) failed to allocate any offshore wind contracts. The UK aimed to award up to 5 GW of contracts for CfDs to offshore wind projects, but no bids were submitted after developers argued the prices offered by the government were too low. The UK lowered the price cap to 44 pounds per MWh ($53.9/MWh, 50.9 €/MWh), down from 46 £/MWh in the previous auction round, despite rising component costs.[423] Developers in the UK and Europe are raising similar concerns as developers in the U.S. regarding rising costs from rising inflation and increasing supply costs. The Swedish energy company Vattenfall estimates that in total its costs have increased by about 40% for offshore wind development.[424]

An NREL study looking at 100% clean electricity generation by 2035 details that for new projects to meet expected demand increases nationwide, an additional 2,000 GW of renewable capacity is needed to meet projected demand growth and to offset fossil retirements.[425] By September 2023, attributing economic pressures from supply chain constraints, inflation, and high interest rates there have been approximately of 2.4 GW of

[419] Disavino, S., & Groom, N. (2023, October 12). New York rejects Orsted, Equinor, BP requests to charge more for offshore wind. Reuters. Retrieved from https://www.reuters.com/sustainability/climate-energy/ny-will-not-change-offshore-wind-other-renewable-power-sales-contracts-2023-10-12/.

[420] PSC Issues Decision to Preserve Competitive Renewable Energy Market and Protect Consumers. (2023, October 12). New York State Department of Public Service. Retrieved from https://dps.ny.gov/system/files/documents/2023/10/pr23105.pdf#:~:text=ALBANY%20%E2%80%94%20The%20New%20York%20State%20Public%20Service,offshore%20wind%20projects%20and%2086%20land-based%20renewable%20projects.

[421] Allocation events are comparable to solicitations or procurement events in the U.S.

[422] Contracts for Difference (CfD) Allocation Round 4: results. (2022, July 7). Retrieved from https://www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-4-results.

[423] Ford, N. (2023, October 13). UK mulls revamp of offshore wind pricing after failed auction. Reuters. Retrieved from https://www.reuters.com/business/energy/uk-mulls-revamp-offshore-wind-pricing-after-failed-auction-2023-10-13/.

[424] Reed, S., & Penn, I. (2023, August 7). Offshore wind runs into rising costs and delays. New York Times. Retrieved from https://www.nytimes.com/2023/08/07/business/offshore-wind-costs-delays.html.

[425] Denholm, Paul, Patrick Brown, Wesley Cole, et al., 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-81644. https://www.nrel.gov/docs/fy22osti/81644.pdf.

announced project cancellations.[426] These announced cancellations are from previously procured offshore wind project contracts. Recent procurement events in the U.S. have also been unsuccessful in filling target amounts.[427] In a joint filing six Atlantic states have asked Treasury and IRS to issue further guidance on ITC and PTC for offshore wind, those states believe that "[w]ithout the guidance we request, up to 10.8 additional GW of our states' previously procured offshore wind projects in the Atlantic are at risk, as are pending and upcoming procurements for up to 13 GW of new offshore wind."[428] Ocean Wind I, the successful bid in New Jersey's first offshore wind solicitation, has encountered setbacks leading to its cancellation. Orsted, the Danish wind energy developer, announced in early November 2023 the abandonment of both Ocean Wind I and II projects off the coast of southern New Jersey. This decision arises from challenges with supply chains, increased interest rates, and the inability to secure desired tax credits. Initially slated to provide over 2.2 GW of power, these projects will no longer proceed as planned.[429]

Current supply chain issues are seeing higher costs which developers are trying to pass on to ratepayers. Developers must recoup costs to finance and bring offshore wind to energization. Without significant alleviation of inflation or supply chain issues, states will be forced to choose between rejecting projects or allowing previously procured projects to cancel.

c) Opportunities and Barriers for Offshore Wind in the Great Lakes and Illinois

i) Opportunities

(1) Legislative Targets

HB 2132 calls for establishing a pilot program for one new utility-scale offshore wind project capable of producing at least 700,000 megawatt hours annually (or have a nameplate capacity that is greater than 150 MW) sited in Lake Michigan. This project must be interconnected to PJM Interconnection's regional transmission system with REC contracts for at least 20 years.

As discussed in the Legislative Proposals chapter, to be eligible for an IPA procurement, the new utility-scale offshore wind project must have a fully executed project labor agreement

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SouthCoast Wind joins Commonwealth in scraping power contracts," *The Salem News* (June 6, 2023), https://www.salemnews.com/news/southcoast-wind-joins-commonwealth-in-scraping-power-contracts /article_0a06a318-04a4-11ee-80d8-4f03ada52794.html.; McDermott et, al., 2023

[427] Rhode Island Energy, "Rhode Island Energy not moving forward on sole bid received in most recent offshore wind solicitation" (July 18, 2023) (news release), https://news.pplweb.com/news-releases?item=137899 , Results Of Gulf Of Mexico Offshore Wind Auction & Recent U.S. Offshore Wind Update–. Conventus Law

[428] Connecticut Department of Energy and Environmental Protection, Maryland Energy Administration, Massachusetts Executive Office of Energy and Environmental Affairs, New Jersey Board of Public Utilities, New York State Energy Research and Development Authority, & State of Rhode Island Office of Energy Resources. (2023, September 27). Re: Offshore Wind Procuring States' Comments on the Inflation Reduction Act of 2022's Energy Community Bonus Credit for Offshore Wind (Notice 2023-29). Retrieved from https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Offshore-Wind/Resource-Library/Multistate-comments-2022-IRA-energy-community-credit.pdf .

[429] Mcdermott et, al. 2023

with the applicable local building and construction trades council for the length of the REC contract. Additionally, the project must meet equity requirements and must submit a comprehensive and detailed equity and inclusion plan outlining how the project will create opportunities for underrepresented local populations and equity investment eligible communities. Before it can bid into a procurement, the project must also secure a permit from the IDNR, pursuant to the Rivers, Lakes, and Streams Act, for a site that is in a preferred area pursuant to Section 15 of the Lake Michigan Wind Energy Act. Funding for such a procurement will be paid for through an adjustment to the line-item tariffs on electricity utility customers' bills that currently fund the Illinois RPS. The current rate impact cap for the RPS requires that retail customers will pay no more than 4.25% of 2009 rates.

Under HB 2132, once a project commences operation, after a 90-day notice to the IPA, the rate impact would increase to 4.5% of the billing month following commercial operations. This would increase annual collections by approximately $33-34 million. Lastly, HB 2132 creates a special state fund in the Illinois State Treasury: the Illinois Rust Belt to Green Belt Fund. It appears that this fund would be used to receive federal funding specifically, although transfers could be taken "from any source, public or private." Managed by DCEO, deposits into the Illinois Rust Belt to Green Belt Fund could then be leveraged for purposes including "financial assistance related to construction of ports and infrastructure" and "workforce development related to offshore wind."

(2) Role of Offshore Wind in Meeting 100% Clean Energy Objectives

A potential offshore wind procurement structure, similar to the IPA's Indexed REC procurements for land-based projects, could be a workable mechanism to support wind project development in Lake Michigan. Under the IPA Act's Indexed REC structure, the Agency deducts from the strike price the actual price of wholesale electricity for the given month the applicable RECs were produced.[430] This market structure is such that the price of the REC could be positive or negative. The Indexed REC approach hedges revenue risk by reference to a market price index instead of the generator's actual commodity revenue. While an Indexed REC structure creates an imperfect hedge, this may still require the developer to manage discrepancy between the price reflected in the market index and the electricity sale value that the generator is receiving.

The current Indexed REC structure for land-based wind procurements in Illinois is still a relatively new market structure in the region. To date, only three wind projects have been selected for Indexed REC contracts. Current uncertainty around interest rates and securing a reliable supply chain has led many developers to pull back their risk appetite to develop a project contracted not only under an Indexed REC structure but through bilateral PPAs with private entities as well.

[430] https://www.ipa-energyrfp.com/wp-content/uploads/2023/08/Indexed-Wind-Solar-and-Brownfield-Final-Indexed-REC-Contract_8-18-2023.docx

(a) Offshore Wind as a potential "Last 10%" Type Solution[431]

Many energy industry analysts argue that the U.S. will need offshore wind to decarbonize its energy supply.[432] A 2022 NREL study on potential pathways to achieve 100% clean electricity generation by 2035 notes that, with the assumed increased electricity demand from electrification, there is need for about two terawatts[433] of renewable capacity to meet this demand projection.[434] NREL estimates that more than one terawatt of combined land-based and offshore wind energy is needed to meet this goal.[435] Further, the Global Wind Energy Council ("GWEC") forecasts that at least 205 GW of new offshore wind capacity will be added globally by 2030.[436] While offshore wind will be a significant source of capacity to meet anticipated electrification induced demand in land-constrained coastal states, in the Great Lakes region (including Illinois), it is unknown exactly how much offshore wind is needed to support states' decarbonization and RPS goals.

(b) Offshore Wind Impacts on Environmental Justice Communities

An offshore wind project, as proposed HB 2132, has the potential to significantly impact environmental justice communities in the Lake Calumet Region of Chicago through constructing one of the potential interconnection points, developing port facilities, and the hiring a local workforce. As discussed in Chapter 8, the offshore wind project's specific interconnection point has not been determined. The Agency modeled interconnection costs at five potential locations, picking one as the primary interconnection point for the purposes of this analysis. The potential points of interconnection are located in environmental justice communities along the Calumet River connecting Lake Calumet to Lake Michigan or along the nearby lakefront of Lake Michigan.[437] Similarly, the location of the associated port facility used in the construction of the wind turbines has not yet been identified but would presumably also be in the Lake Calumet Region which is entirely made up by environmental

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431 Many researchers have demonstrated that cost-effective high-renewable power systems are possible, but costs increase as systems approach 100% carbon-free electricity and what has become known as the "last 10% problem" to solve this.

432 Paliwal, U., Abhyankar, N., McNair, T., Bennett, J.D., Wooley, D., Matos, J., O'Connell, R. and Phadke, A. 2023. 2035 and Beyond: Abundant, Affordable Offshore Wind Can Accelerate Our Clean Electricity Future. Goldman School of Public Policy, University of California, Berkeley; (Denholm et al., 2022); (Paliwal et al., 2023); (EERE, 2022)

433 Two terawatts is equivalent to 200,000 MW.

434 Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-81644. https://www.nrel.gov/docs/fy22osti/81644.pdf

435 Wiser et al., 2023

436 Lee, J., & Zhao, F. (2020). (rep.). Global Offshore Wind Report 2020. Global Wind Energy Council. Retrieved from https://gwec.net/wp-content/uploads/2020/12/GWEC-Global-Offshore-Wind-Report-2020.pdf.

437 For a map of environmental justice communities in Illinois, as used in the IPA's Illinois Solar for All Program see: https://elevate.maps.arcgis.com/apps/webappviewer/index.html?id=d87a45c18a5c4e0fa96c1f03b6187267. This map is based a methodology contained in the Agency's Long-Term Renewable Resources Procurement Plan which calculates the top 25% of census tracts in Illinois based on a formula that utilizes eleven environmental and six demographic indicators and designates them as environmental justice communities. For more information, see Section 8.12 of the Long-Term Plan, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/modified-2022-long-term-plan-upon-reopening-9-may-2022-final.pdf. Note that this methodology differs slightly from that used by other State agencies in that it includes racial and ethnic demographics. This is due to the differing definitions of Environmental Justice Communities used in different Illinois Statutes, but does not have a significant impact on the mapped areas.

justice communities. Investments in new infrastructure would bring tens of millions of dollars into the community and could potentially include site remediation activities if brownfield sites are used for interconnection facilities, staging, or port facilities. However, these potential benefits are beyond the scope of the analysis done in this study as HB 2132 does not feature an identified site for construction for a potential demonstration project.

Beyond the direct impact on the built environment, HB 2132 includes provisions related to equity that would benefit the communities where the onshore portions of the project are located. Specifically, HB 2132 requires the development of an Equity and Inclusion Plan ("Plan") that would be filed with DCEO. DCEO then would score that Plan, requiring a minimum score for projects participating in an IPA-conducted procurement. The Plan would have to include one or more community benefit agreements with community-based organizations located in the area and create opportunities for underrepresented populations and equity investment eligible communities.

Underrepresented communities are defined in HB 2132 as populations identified by DCEO that historically have had barriers to entry or advancement in the workforce and reside within a disproportionately impacted area that is within three miles of the primary staging location of a new utility-scale offshore wind project. Underrepresented populations include, but are not limited to, minorities, women, and veterans. While the staging location for the proposed offshore wind project is not yet known, if it is in the Lake Calumet region, then the given area would consist of environmental justice communities.

HB 2132 also references equity investment eligible communities in the requirements for the Equity and Inclusion Plan. The definition of these communities in the Illinois Power Agency Act is broader than the definition of environmental justice communities as it also includes R3 communities, which are communities that have been harmed by violence, excessive incarceration, and economic disinvestment.[438] This designation was developed as part of the cannabis legalization process in Illinois, and largely overlaps environmental justice communities. Therefore, the use of equity investment eligible communities would not have as meaningful an impact compared to a consideration of solely environmental justice communities.

The provisions proposed in HB 2132 provide a framework that not only ensures that economic benefits created by the proposed offshore wind project would accrue to nearby environmental justice communities, but also creates opportunities to address the historic negative impacts of pollution in the area.

[438] See: https://r3.illinois.gov/ for more information on R3 communities, and https://energyequity.illinois.gov/resources/equity-investment-eligible-community-map.html for a map of Equity Investment Eligible Communities.

ii) Barriers to Offshore Wind Deployment in the Great Lakes and Illinois

(1) Interconnection Barriers

An offshore wind project in Lake Michigan has the potential to bring hundreds of megawatts of power via a high voltage cable to a land-based point of interconnection ("POI") to deliver power to Illinois customers. One objective of this Policy study is to develop an understanding of the feasibility of the interconnection of an offshore wind project to the grid and to inform general feasibility from an interconnection perspective. The results of an analysis of several interconnection scenarios are elaborated in Chapter 8.

(a) PJM

While the potential offshore wind project in Lake Michigan could interconnect to several POIs in Illinois, these existing connections are unlikely to accommodate large amounts of power from an offshore wind project as many are near capacity. The electricity grid network in the Great Lakes Region is congested, and significant upgrades are needed to accommodate large injections of new load.[439] Unless existing generation at current POIs are retired, or the transmission facilities are upgraded to accommodate new generation, an offshore wind project would most likely need to make major investments and have significant development on land to be able to interconnect the project. POI limitations are elaborated further in Chapter 8(c). Interconnection opportunities in PJM require comprehensive analyses, such for as power flow and contingency modeling, production cost modeling, and system stability assessments. The high-level analyses conducted for this Policy Study are applicable as a preliminary screening step. This included considering several POIs for what interconnection upgrade investments would be needed. Looking at the Icebreaker project (discussed previously), a 2016 study identified technical challenges and planning requirements for a 1 GW of offshore wind energy on Lake Erie located in PJM's grid.[440] The project proposal used a single POI on the existing Cleveland Public Power electric grid a 138 kilovolt (kV) Lake Road Substation.

New injections of offshore wind energy in these regions would require significant onshore high-voltage transmission upgrades and/or thermal power plant retirements to free up capacity. Additionally, FERC Order No. 2023 determined that current interconnection procedures for load serving entities are insufficient and hinder the development of new generation.[441] This is impacting RTOs' interconnection queue processes and is significantly overhauling the process to ensure that interconnection seekers can interconnect onto the

[439] Sajadi, A., K. A. Loparo, R. D'Aquila, K. Clark, J. G. Waligorski, S. Baker. June 2016. Great Lakes Offshore Wind Project: Utility and Regional Integration Study. https://www.osti.gov/servlets/purl/1328159.

[440] Sajadi, A., K. A. Loparo, R. D'Aquila, K. Clark, J. G. Waligorski, S. Baker. June 2016. Great Lakes Offshore Wind Project: Utility and Regional Integration Study. https://www.osti.gov/servlets/purl/1328159.

[441] Docket No. RM22-14-000; Order No. 2023

transmission system in a reliable, efficient, transparent, and timely manner. Additionally, the PJM queue reform now operates under a "first-ready, first-served" cycle approach.[442]

NYSERDA's 2022 Great Lakes Feasibility Report shows that POIs in Lake Erie have a potential maximum transmission capacity headroom of 270 MW while POIs in Lake Ontario have a potential maximum transmission capacity headroom of 1,140 MW without transmission upgrades made in either region.[443] Consistent with the PJM queue reform, NYSERDA notes that "headroom represents the potential capability for Great Lakes Wind ("GLW") to interconnect; however, it also represents the capacity that is available to any other generation resource that may want to interconnect at the same POI. The nature of the NYISO market for new generation is competitive and GLW is expected to compete with other resource developments to utilize the available headroom."[444] Shovel-ready projects in the region could also compete and take available headroom capacity, leaving offshore wind out of available capacity to interconnect at shoreline POIs. The rest of Lake Michigan in the MISO region has land-based POIs. According to NREL in 2023, MISO short- and mid-term transmission capacity assessments, the northern area of the MISO system, including around the Great Lakes, is heavily congested in the 5-year-ahead period of analysis.[445] This leaves little headroom for additional new capacity in the region. Given queue backlogs in both PJM and MISO, any new offshore wind projects will not see an interconnection date for several years, both delaying construction and procurement eligibility as defined in current proposed legislation.

(2) Financing Barriers

Critical to the success of any offshore wind project is securing financing. For a project to succeed in energization, financial capital for offshore wind faces major challenges. A project needs secure early years financing, policy support for project financial solvency, workforce development, and transmission and interconnection agreements.[446] Since the IRA's enactment, options for developers to secure financial solvency have increased.

(a) Capital Costs

Project capital expenses are the largest hurdle to move the project forward. Looking at a LCOE, the capital expenditures ("CapEx") would be capital costs per kilowatt required to reach commercial operation. This would include materials and equipment, installation, project development, and moving costs such as site development, permitting, environmental mitigation, insurance, and construction financing. Capital costs also include

442 Docket Nos. ER22-2110-000, ER22-2110-001

443 NYSERDA, 2022

444 NYSERDA, 2022

445 NREL, 2023

446 Hansen, T. A., Wilson, E. J., Fitts, J. P., Jansen, M., Beiter, P., Steffen, B., ... & Kitzing, L. (2024). Five grand challenges of offshore wind financing in the United States. Energy Research & Social Science, 107, 103329.

decommissioning costs. LCOE is used to compare costs of different generation sources. An LCOE calculation would include operational expenditures ("OpEx"), energy production, and financing terms of the project. This is consistent with NREL's Offshore Regional Cost Analyzer ("ORCA").[447] OpEx includes the cost of labor, facilities, equipment, and materials used in day-to-day operations, maintenance, and repairs, in dollars. LCOE is used to compare costs of different generation sources. This report provides a projection of costs for 2030 energization of offshore wind in Lake Michigan.

NREL found the mean CapEx for all the Great Lakes for their Current Scenario ranges from $2,000/kW to $3,600/kW. For the Advanced Research Technology Scenario, CapEx ranges from $1,900/kW to $2,600/kW.[448] Lake Michigan and Lake Erie have the lowest CapEx costs in this range. NREL notes that for fixed-bottom projects, the water depth is a major cost component of differences between lakes' CapEx. Additionally, substructure installation costs are a significant CapEx factor differential. The variation in costs depends on distance to the installation port and water depth of each lake. Actual costs of installation also will greatly vary depending on timing of development compared to other offshore wind development, with early entrants facing higher costs than later entrants.

NREL's estimates of OpEx found that for all lakes in their Current Scenario, all OpEx costs associated with operating a wind power plant aggregate to a range of $85/kW-yr to $156/kW-yr, and their Advanced Research Technology Scenario, range from $63/kW-yr to $96/kW-yr.[449] One driver of cost reduction between the scenarios is wind turbine size. Fewer 17 MW turbines are needed compared to 6 MW turbines for a plant to have the same capacity. Needing fewer turbines can reduce maintenance. Given the constraints of the St. Lawrence Seaway (explained further in the construction challenges section), any turbine to be installed in the near term within Lake Michigan is unlikely to be larger than 6 MW.

NREL notes that more observational wave data is needed to better model how O&M costs are impacted because higher wave heights increase O&M costs. NREL's 2023 Great Lakes Report estimates for the 2035 LCOE of offshore wind in the Great Lakes in the assumed "Current Scenario" range the LCOE is $75/MWh to $129/MWh.[450] The mean LCOE across all lakes in the Current Scenario is $103/MWh. This puts Great Lakes offshore wind costs much higher than onshore wind. EIA estimates that the LCOE for incremental onshore wind capacity ranges from $30.01 to $65.65/MWh.[451] This makes current estimates of offshore wind in the Great Lakes not a competitive intermittent substitute for onshore wind. However, according to NREL, if there was opportunity to develop under their outlined

[447] Musial, W., Duffy, P., Heimiller, D., & Beiter, P. (2021, September 24). Updated oregon floating offshore wind cost modeling - NREL. https://www.nrel.gov/docs/fy22osti/80908.pdf

[448] The CapEx mean for the Current Scenario is $2,993/kW, the Advanced Research Technology Scenario mean is $2,178/kW; (NREL, 2023)

[449] The OpEx mean for the Current Scenario is $122/kW-yr, the Advanced Research Technology Scenario mean is $79/kW-yr

[450] NREL, 2023

[451] U.S. Energy Information Association. (2022). Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022. US Department of Energy, January. Levelized Costs of New Generation Resources in the Annual Energy Outlook 2022 (eia.gov)

Advanced Research Technology Scenario the LCOE could potentially be $62/MWh to $89/MWh, with a mean of $74/MWh.[452] This would make the low end of NREL's estimates competitive with the high end of EIA's LCOE estimates for onshore wind. However, without significant investment in supply chain infrastructure, NREL's Advanced Case scenario is currently unfeasible in the Great Lakes due to vessel size limitations.[453]

NYSERDA used the NREL ORCA model for Lake Erie and Lake Ontario, which assumes a turbine rating of 6 MW, and found the estimated LCOE for the Great Lakes bordering New York "(f)or wind plants beginning operations in 2030, LCOEs range from $96/MWh to $118/MWh with a median value of $105/MWh in Lake Erie and between $97/MWh and $115/MWh with a median value of $103/MWh in Lake Ontario."[454] These cost estimates are higher than NREL's estimates. The lower end of the range is for the eastern portion of each lake in New York, due to nearby potential ports and available POIs located near large load centers (Buffalo and Oswego). NYSERDA's analysis looked at alternative scenarios and found an increase of 51% to 55% in LCOE when modeling a 400 MW plant compared to a 100 MW plant.[455] NREL's analysis shows that Lake Erie has the lowest average LCOE in the Current Scenario but in an Advanced Research Technology Scenario, costs in Lake Michigan could be lower than in Lake Erie.

NREL concludes that Lake Michigan has a higher capacity factor for wind development causing the price differential. NREL estimates the LCOE range for Lake Michigan under the Advanced Research Technology could be as low as $71/MWh.[456] For any of the Great Lakes, the cost averages to be 27.5% lower under the Advanced Research Technology Scenario than the Current Scenario.[457] This is due to economies of scale improving the CapEx value as well as the OpEx value.

NYSERDA further concluded that technology advancements are needed to reduce costs. Examples of these improvements include: the ability to install larger turbines (greater than 6 MW), increased plant size (closer to 1 GW),[458] improved supply chain synergies, additional industrialization, and greater economies of scale. While not all encompassing, NYSERDA's recommendations to mitigate current cost constraints are seemingly unlikely to less in the near term to meet DOE's 2030 target.

[452] NREL, 2023

[453] NREL, 2023

[454] NYSERDA, 22-12

[455] NYSERDA, 22-12

[456] NREL, 2023

[457] NREL, 2023

[458] While NYSERDA's analysis found LCOE increases of 51% to 55% to a 400 MW plant from a 100 MW plant, but found a cost decrease from 400 MW to 800 MW was about 2% across Lake Ontario (See Table 25).

(b) RPS Budget Limitations

As discussed above, under current Illinois law, line-item tariffs on utility customers' bills include a rate cap for retail customers of no more than 4.25% of 2009 rates to support the State's RPS. This equates to a maximum allocated funding of roughly $580 million per year. An increase of 0.25% to that 4.25% would collect an additional ~$34 million per year. Given the proposed requirement in HB 2132 that the offshore wind project deliver at least 700,000 RECs per year, this increase would result in an imputed REC price of $45.71.

(c) Economic Feasibility in a Competitive Market

Given large investment costs for floating or fixed base turbines needed for offshore wind development in Lake Michigan, high LCOE are needed to recoup costs through electricity generation. Electricity rates are low in Illinois compared to the Midwest. The Midwest has lower electricity rates relative to much of the country, including the East Coast. Illinois and much of the Midwest has significant amounts of renewable energy provided by land-based wind power plants compared to oceanic states, specifically when compared to the East Coast. One factor that will be advantageous to offshore wind developers and will lower costs compared to oceanic offshore wind development is jurisdiction of the Great Lakes. Individual states will have the ability to license offshore wind energy projects in their respective state waters, unlike oceanic offshore wind developments which must go through BOEM permitting processes.[459]

Offshore wind is classified as an intermittent resource, and modelling suggests higher output in the winter than other seasons. This is discussed further in the Aurora production cost model (Appendix E). As explained in Chapter 8, the estimated summer output profile for a potential offshore wind project as outlined in HB 2132 has the potential to complement Illinois solar output as offshore wind generation is lowest during the middle of the day, the time when solar output would be the highest. However, offshore wind would not be able to fully mitigate the loss of solar production during a day as offshore wind does not traditionally contain a strong evening ramp up of production as solar production would be trailing off. Traditionally Illinois has had a summer-peaking in load profile. With the ongoing electrification of buildings, and the growth of electric vehicles, this may shift to a winter peak and the seasonality of offshore wind may better match the seasonality of peak demand.

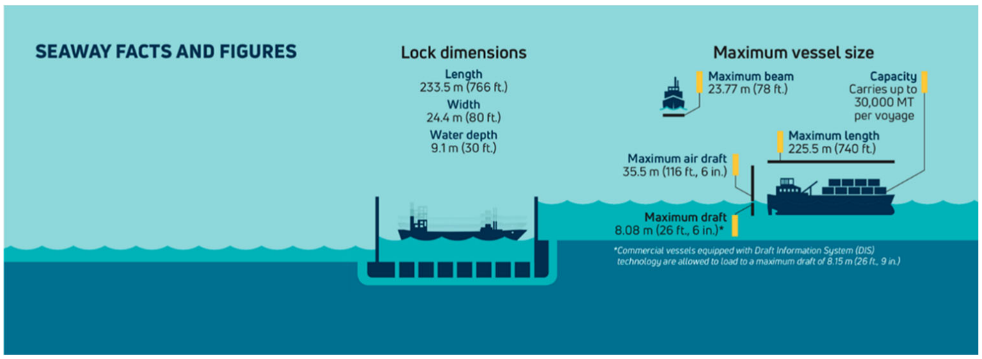
(3) Construction Challenges

The narrow locks of the St. Lawrence Seaway limit some conventional installation and construction vessels from entering the Great Lakes and limit the potential size of turbines (See Figure 6-5). Ocean-based wind turbine installation vessels capable of lifting offshore wind turbines (up to 12 MW) are too wide to move through the locks of the St. Lawrence Seaway to reach the Great Lakes, despite the existing extensive port and manufacturing

[459] Bureau of Ocean Energy Management (BOEM). (2011). Renewable energy on the Outer Continental Shelf https://www.boem.gov/sites/default/files/uploadedFiles/Fact Sheet BOEM Renewable Energy.pdf

infrastructure in the Great Lakes region.[460] Without vessels designed around canal limits in the Great Lakes, construction will not be possible until that issue is resolved. Vessels will also be needed for other aspects of offshore wind energy for cable laying, or O&M might not be sized correctly to navigate the St. Lawrence locks. Solutions to overcome this limitation on vessel size are needed, as the size of the St. Lawrence Seaway in the near term will not increase. A potential near-term solution could be retrofitting existing Great Lakes vessels or building new vessels specifically for the Great Lakes.

Figure 6-5: St. Lawrence Seaway Size Constraints[461]



As noted in NYSERDA's Great Lakes Wind Energy Infrastructure Assessment, the Jones Act[462] impacts the eligibility of vessels that can be used to install wind turbines on the Great Lakes.[463] The Jones Act requires that all vessels transporting goods between U.S. ports must be built, registered, owned, and crewed by U.S. citizens. An assessment of port capabilities in Illinois is not included in this report.

U.S. offshore wind supply chains and infrastructure continue to develop where ports, vessels, manufacturing, and the electric grid are seeing active investment. More than $2 billion was invested in 2022 alone.[464] NREL estimates that ports, large installation vessels, and major manufacturing facilities need more than $22 billion in additional investments to meet DOE targets.[465] However, offshore wind in the Great Lakes would require additional supply chain investments.

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[460] This current infrastructure is not fully pledged to OSW and has current incumbent industries it serves. Offshore Wind Energy Strategies Report.

[461] Great Lakes St. Lawrence Seaway Development Corporation n.d. The Seaway - Great Lakes St. Lawrence Seaway System (greatlakes-seaway.com)

[462] The Jones Act is also called the Merchant Marine Act of 1920 and is a federal statute establishing support for the development and maintenance of a merchant marine.

[463] New York State Energy Research and Development Authority (NYSERDA). 2022. "New York State Great Lakes Wind Energy Feasibility Study: Infrastructure Assessment," NYSERDA Report Number 22-12d. Prepared by the National Renewable Energy Laboratory, Golden, CO. nyserda.ny.gov/publications

[464] Business Network for Offshore Wind 2023

[465] Shields, Matt, Jeremy Stefek, Frank Oteri, Matilda Kreider, Elizabeth Gill, Sabina Maniak, Ross Gould, Courtney Malvik, Sam Tirone, and Eric Hines. 2023. "A Supply Chain Road Map for Offshore Wind Energy in the United States." Golden, CO: National Renewable Energy Laboratory (NREL). NREL/TP-5000-84710. https://www.nrel.gov/docs/fy23osti/84710.pdf.

Another construction challenge is the availability of port facilities for the development of offshore wind. The IPA is unaware of any detailed record of ports that could support future wind energy development in Lake Michigan, but all currently active ports would require upgrades if they were to support offshore wind in Lake Michigan. NREL's 2023 report for floating wind turbines in the Great Lakes recommends that ports install substructure fabrication like ocean-based floating offshore wind energy projects to minimize costs long-term if multiple projects were to be developed.[466] Given the unlikelihood of floating turbines being installed in Lake Michigan anytime soon, and given the size constraints of the St. Lawrence Seaway, fixed-bottom wind systems would be a more likely substructure type, like those that were proposed for Icebreaker. Any potential substructure fabrication ports could be designed for vessels to float out installations already assembled onshore at port facilities. NYSERDA outlines possible jack-up barges or custom modular barges that could accommodate a large land-based crawler crane to assemble the turbine on the water.[467]

Until current manufacturing ports have been updated and are in operation on the Great Lakes to support offshore wind, turbine and substructure components will need to be transported from other manufacturing facilities. These outside components will need to enter the Great Lakes ports by either water, rail, or highway. Depending on the type of ports developed for offshore wind, the components could be offloaded to either a staging area at a port, a floating barge staging area, or the installation vessel.[468] Not only is there need for a manufacturing port, but O&M ports and marshalling ports are needed to support the project throughout all stages of its lifecycle. While not within the scope of this Policy Study, further research on port readiness to support offshore wind development in Illinois may be needed.

(4) Environmental Concerns

The environmental impacts and interactions of any proposed project, including wind turbines, inter-array cables, export cable, substation, O&M, port staging area, and any associated workspace, are important. Offshore wind project regulatory approval processes must also consider the size and scope of the project on Lake Michigan and the type of impact the project has (whether adverse or beneficial), the impact duration, and intensity of such an impact.[469] In its environmental impact assessment of the Icebreaker project, DOE focused on environmental impacts that had greater probabilities of happening. This assessment could serve as guide for regulatory frameworks for possible interactions of offshore wind development in Lake Michigan, noting that DOE did not conduct a detailed analysis on many relevant environmental interactions, such as Icebreaker's impact on land use (e.g., the

[466] NREL, 2023

[467] NREL, 2023

[468] NYSERDA 22-12d.

[469] DOE/EA-2045, 2018

lakebed).[470] Importantly, offshore wind development in Lake Michigan must follow all federal and State environmental laws.[471]

Further, future environmental studies for offshore development in Lake Michigan will need better spatial data for birds and bats flying over the lakes, including data on flight paths, flight height, magnitude of birds and bats flying over the lake, and changes in flight patterns over the lakes relative to weather and light conditions, as similarly noted in NYSERDA's Great Lakes assessment.[472] Additionally, research in defined Environmental Study Areas will be needed to analyze the habitat use patterns and movements of most fish, as well as the distribution and use patterns of fisheries.

(a) Environmental Impacts

Given the number of diesel burning vessels needed to construct an offshore wind project, offshore wind development policy in the Great Lakes should take full account for the environmental impacts of offshore wind facilities. For oceanic development, BOEM has developed a tool to estimate site characterization, construction, operation, and decommissioning activities of vessels and their related estimated emissions. Before allowing leases to offshore land for development, states must require developers to conduct studies estimating potential emissions to quantify marine vessel, emergency generator, and helicopter emissions associated with offshore wind site assessment, construction, maintenance, and decommissioning.[473]

To justify the development of a new offshore wind project, emissions estimations must quantify the displacement of conventional power generation that offshore wind projects replace and must quantify the associated avoided GHG and criteria pollutant emissions from offshore wind development. The anticipated energy quantity the project is projected to produce should then be compared to the amount of energy that is avoided by using electricity generated from the offshore wind project. The U.S. EPA's Emissions & Generation Resource Integrated Database tracks emissions from electricity generating units in the United States.[474]

Some unique environmental issues to be addressed for Great Lake offshore wind development, such as possible avian interactions, include assessing wind project interactions with the multiple endangered migratory species that fly over Lake Michigan. Given that Lake Michigan is located within the Mississippi flyways (

[470] DOE/EA-2045

[471] Permitting and approval subject to Fish and Wildlife Coordination Act (16 U.S.C. 661-666(e)), the Endangered Species Act (16 U.S.C. 1531-1544), the Migratory Bird Treaty Act(16 U.S.C. 703-712), and the Bald Eagle Protection Act (16 U.S.C. 668-668d).

[472] NYSERDA 22-12i, 2022

[473] Chang, R., S. Mendenhall, C. Lamie, H. Perez and R. Billings. 2021. User's Guide for the Offshore Wind Energy Facilities Emission Estimating Tool, Version 2.0. U.S. Department of the Interior, Bureau of Ocean Energy Management, Sterling, VA. OCS Study BOEM 2021-046. 32 pp

[474] Emissions & Generation Resource Integrated Database (egrid) | US EPA. (2023, December 18). https://www.epa.gov/egrid A

Figure 6-6) which are designated as major corridors of bird migration in North America, further analysis should be done on potential interactions with the millions of birds that use this corridor—some of which are protected by the Migratory Bird Treaty Act due to having status as endangered, threatened, or are classified as a species of concern.[475]

Therefore, wind turbines in Lake Michigan will need to be sited in an area that avoids migratory bird flight paths (See Figure 6-6). For example, the Icebreaker project in Ohio was held up for several years because of concerns that the turning offshore wind turbine blades could kill too many migratory birds.[476] The Ohio Power Siting Board's technical staff insisted that, as proposed by concerned parties, halting turbine operations at night for 10 months per year to protect migrating birds would make the project economically nonviable and effectively end the project. In Icebreaker's bird and bat report, LEEDCo found that collision, displacement effects, and avoidance or attraction effects for birds was low risk.[477] The Ohio Environmental Protection Agency ruled that the project installation would comply with federal standards relating to water pollution and avian interaction.[478] NYSERDA's feasibility study recommends that additional data is needed from radar stations, acoustic detectors, thermal imaging, or radiotracking of bird and bat species to provide a better understanding of how species are migrating and foraging over the lakes.[479]

[475] U.S. Fish and Wildlife Service, 2021

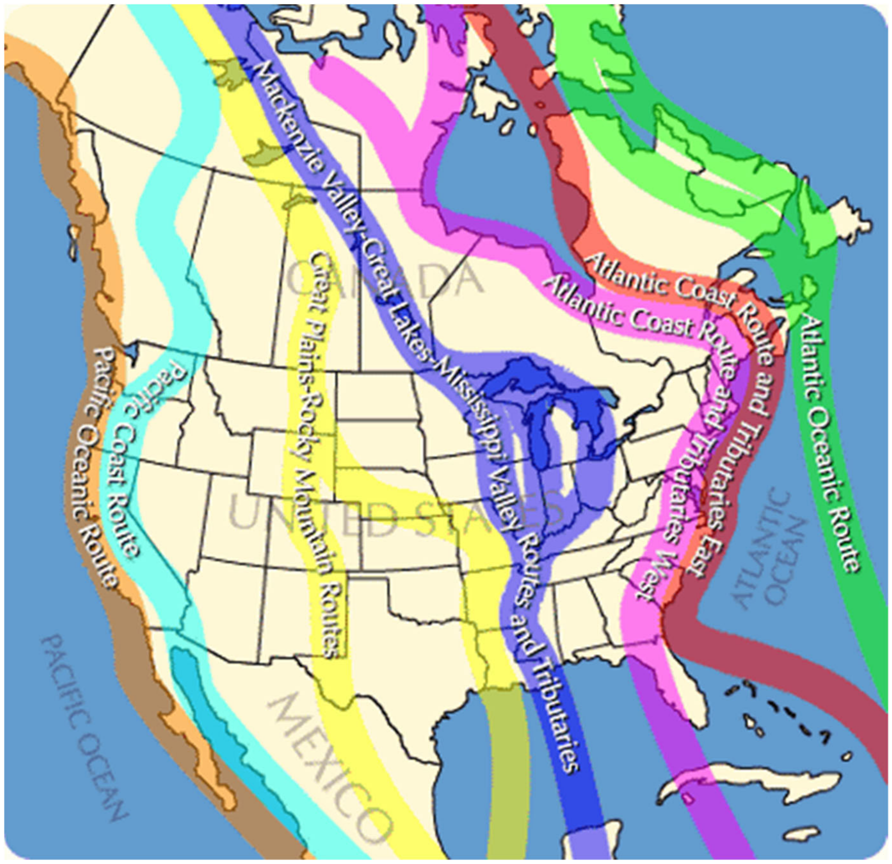
[476] McGraw, D. (2018, August 15). Can offshore wind turbines succeed in the Great Lakes?. Scientific American. https://www.scientificamerican.com/article/can-offshore-wind-turbines-succeed-in-the-great-lakes/

[477] Caleb, G., et. al., Icebreaker Wind Bird and Bat Monitoring Lake Erie, Ohio (2018). WEST Bird and Bat Annual Report 2018 . Retrieved December 21, 2hjn023, from https://www.energy.gov/sites/default/files/2018/09/f55/EA-2045_Appendix_L-2_WEST_Bird_Bat_Annual_Report_2018_0.pdf.

[478] Ohio Environmental Protection Agency. (2017, September 22). Ohio EPA Public Notice Icebreaker Wind. Ohio EPA Public Notice. https://ebiz.epa.ohio.gov/Notices/jsp/view_notice.jsp?noticeID=33279

[479] New York State Energy Research and Development Authority (NYSERDA). 2022. "New York State Great Lakes Wind Energy Feasibility Study: Relative Risks, Minimization/Mitigation, and Benefits," NYSERDA Report Number 22-12i. Prepared by Worley Group, Inc. (dba Advisian), Reading, PA. nyserda.ny.gov/publications

Figure 6-6: Migratory Bird Flyways[480]



Additionally, other flying species that face population threats, such as Monarch Butterflies and several bat species, use the Lake Michigan shoreline as a migratory path. The Great Lakes also have many fish and invertebrate species. The IDNR's *Lake Michigan and Coastal Area Campaign* report notes that, "the present day Lake Michigan fish community includes a diversity of native and nonnative species that comprise a highly managed and unstable fishery."[481] Further, the National Oceanic and Atmospheric Administration's ("NOAA") Great Lakes Environmental Research Laboratory conducts regular lake-wide benthic surveys tracking changes in invertebrate species, such as invasive Zebra and Quagga Mussels, in Lake Michigan.[482] Similar to the NYSERDA environmental analysis for any invertebrate, such as invasive zebra mussels who prefer hard substrates to grow, a turbine structure may further spread of this species.[483]

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480 Source: https://www.ilbirds.com/Environment/BirdMigration/sub/na_flyways.html.

481 Illinois Department of Natural Resources. (n.d.). Lake Michigan and Coastal Area Campaign - Illinois.gov. https://www2.illinois.gov/dnr/xxconservation/IWAP/Documents/LakeMichiganCampaign2022.pdf

482 U.S. Department of Commerce, N. (2023, August 30). Ecosystem Dynamics. NOAA Great Lakes Environmental Research Laboratory - Ann Arbor, MI, USA. https://www.glerl.noaa.gov/res/Programs/eco_dyn/eco_dyn.html

483 New York State Energy Research and Development Authority (NYSERDA). 2022. "New York State Great Lakes Wind Energy Feasibility Study: Relative Risks, Minimization/Mitigation, and Benefits," NYSERDA Report Number 22-12i. Prepared by Worley Group, Inc. (dba Advisian), Reading, PA. nyserda.ny.gov/publications

Fish in Lake Michigan will have also numerous interactions with potential offshore wind development but there is little research on distribution and use patterns of fish in Lake Michigan. However, in general, most fish in the Great Lakes spawn in nearshore areas which likely have more interactions or are more vulnerable to disturbance of fish when an offshore wind project is being developed. Further, there is concern that invasive fish species could be introduced into the Great Lakes via vessels, which is an important factor to analyze before project development.

Currently, four species of Asian carps[484] threaten Great Lakes fisheries.[485] If vessels needed for offshore wind development were to use Illinois waterways, many of which currently use barriers[486] to prevent Asian carp from spreading into the Great Lakes system, vessels using Illinois waterways to reach Lake Michigan will need to take significant precautions. As noted in NYSERDA's 2018 Great Lakes Feasibility Study, "[m]arine fish with swim bladders have more potential to be injured by sound and particle motion than fish without swim bladders, but little is known about the potential for freshwater fish with swim bladders to be impacted by sound or the potential behavioral reactions of Great Lakes fish to sound, electromagnetic fields, and other disturbance."[487] Construction vibrations have an unknown potential to harm swim bladders of freshwater fish in Lake Michigan unless further studies are conducted to determine impact.

Possible toxins in near-shore sediments must also be addressed before offshore wind project transmission and foundations can be laid. Given Lake Michigan's industrial history, potential offshore sites in Illinois will need proper environmental studies. Lake Michigan, unlike other Great Lakes, is not a part of the Great Lakes Sediment Archive Database,[488] therefore site-specific geotechnical surveys, which are industry standard in wind power plant development process to analyze soil strength, have not been conducted. A study of lakebed soil characteristics informs offshore wind development substructures or anchoring solutions based on known data of the other lake beds, such as what are the common soil types in the Great Lakes and where it is optimal to build given these soil types. Installing wind turbine foundations, anchors, and power cables require developers to disturb the soil at and below noted distribution of contaminants from the Lake's industrial history, including disturbing heavy metals such as mercury. The U.S. Army Corps of Engineers' Great Lakes Dredging Team

[484] Bighead carp, silver carp, black carp, and grass carp are of threat, however bighead carp and silver carp, and grass carp are of substantial risk.

[485] IDNR, 2013, [Asian Carp (illinois.gov)]

[486] 2002 the Army Corps of Engineers had finished construction of a demonstration electric barrier near Romeoville, IL on the Illinois river, since then multiple barriers have been constructed to prevent the spread of asian carp. [Chicago District Civil Works Projects (army.mil)]

[487] NYSERDA 22-12i

[488] Government of Canada, E. and C. C. C. (2013, July 23). Archived - great lakes sediment database - national water research institute. ARCHIVED - Great Lakes Sediment Database - National Water Research Institute. https://ec.gc.ca/inre-nwri/default.asp?lang=En&n=9890771E-1.

provides information regarding best practices for managing sediments that are disturbed or removed from the lakebed.[489]

As outlined in the 2012 Lake Michigan Offshore Wind Energy Report, a potential offshore wind project must address the environmental concerns such as various environmental studies on Natural Resource Factors, Marine Factors, Public Infrastructure, and Transportation/Security which is consistent with the studies done for Lake Erie Icebreaker project.[490]

(iv) Icing

Icing is a concern as all of the Great Lakes have seasonal ice coverage. Lake Erie freezes most often, with a maximum annual average of 82% ice cover. Lake Huron, Lake Superior, Lake Michigan, and Lake Ontario average a maximum of 30% ice cover.[491] Research at NOAA's Great Lakes Environmental Research Laboratory shows the variability of Great Lakes ice cover is heavily influenced by four climate patterns: the North Atlantic Oscillation, the Atlantic Multidecadal Oscillation, the El Nino/Southern Oscillation, and the Pacific Decadal Oscillation.[492] These four climate patterns, or teleconnection patterns, impact not only the Great Lakes' regional climate but also the ice cover because these weather patterns influence the location of the westerly jet stream over North America.[493] Ice ridges, or a linear pile-up of ice, are common with surface ice in the Great Lakes. These ridges could potentially pose large risks to offshore wind structures and power cables. Ice in the water can also impede repair and cleanup efforts. A relevant example is when oil used for electrical insulation of a transmission line leaked in 2018 under the Straits of Mackinac.[494] While not resulting in a loss of power, about 600 gallons of oil were released into the Strait. The risk of oil release into the Great Lakes is not a concern with modern transmission cable technology. However, the concern of ice scraping the lakebed is still a known risk, and there has been direct evidence of ice ridges via satellite, and indirect evidence of scouring on the lakebed due to ice ridges that may be caused by ice traveling from deep to shallow water. [495]

Icing mitigation is impacted by substructure choice and waterline profiles of a structure. The force that ice exerts on an offshore wind substructure is directly related to the force required

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[489] Great Lakes Dredging Team. Detroit District, U.S. Army Corps of Engineers. (n.d.). https://www.lre.usace.army.mil/Missions/Great-Lakes-Information/Great-Lakes-Dredging-Team/

[490] See Table 2

[491] U.S. Department of Commerce, N. (2023b, October 2). Great Lakes Ice Cover. Ice Cover: NOAA Great Lakes Environmental Research Laboratory - Ann Arbor, MI, USA. https://www.glerl.noaa.gov/data/ice/

[492] Wang, J., Kessler, J., Bai, X., Clites, A., Lofgren, B., Assuncao, A., Bratton, J., Chu, P., & Leshkevich, G. (2018). Decadal Variability of Great Lakes Ice Cover in Response to AMO and PDO, 1963–2017. Journal of Great Lakes Research, 44(1), 1-11. https://www.glerl.noaa.gov/pubs/fulltext/2018/20180013.pdf)

[493] Wang et. al, 2018; Bai and Wang, 2012

[494] Bergquist, L. 2018. "Electric cables under Straits of Mackinac damaged in weekend accident."

Milwaukee Journal Sentinel. https://www.jsonline.com/story/news/local/wisconsin/2018/04/03/electric-cables-under-straitsmackinac-damaged-weekend-accident-power-shutdown-system/483038002/

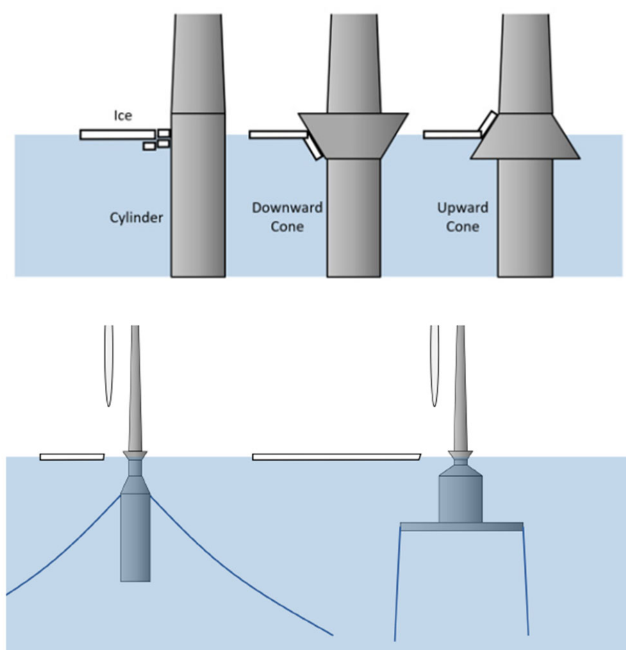
[495] NREL, 2023

to break the ice sheet as it contacts the structure. This breaking force can vary ice failure dependent on the ice sheet and substructure design. When the ice sheet contacts a vertical substructure, the ice is crushed as it moves past, putting the highest load on the substructure (see Figure 6-7). As NREL notes, "ice ridges are possibly the least well-understood features of surface ice in the Great Lakes but may pose the highest risk to offshore wind structures and power cables."[496] These ice ridges can form when ice sheets collide while floating chunks of ice gather above and below the waterline where the sheets intersect, and can then freeze together into a mass that is much taller and deeper than the original flat ice sheets. This will look like an iceberg in the ocean. Power cables would not be immune from potential damage as ice ridges can scour the lakebed and get closer to shore.[497] The extent to which ice ridges could have a potential to impact structures such as wind turbine foundations is still highly uncertain due to the lack of site-specific data. Without measured quantified ice ridge sizes, if developers were to use best industry practices, wind turbine substructures should be feasible in the Great Lakes.

Figure 6-7: Potential Impacts of Icing on Turbines[498]

Figure 20. Potential Ice Interactions with Fixed and Floating Turbines

(Top: Crushing failure induced in vertical profiles (left) and flexural failure induced in downward sloping (middle) and upward sloping (right) profiles. Bottom: Floating substructures (spar left and tension leg platform right) outfitted with similar ice cones to deflect and break ice sheets in flexure mode.)



[496] NREL, 2023

[497] Hawley, Nathan, Dmitry Beletsky, and Jia Wang. 2018. "Ice thickness measurements in Lake Erie during the winter of 2010–2011." Journal of Great Lakes Research 44(3): 388–97. https://doi.org/10.1016/j.jglr.2018.04.004.

[498] NYSERDA original, New York State Energy Research and Development Authority (NYSERDA). 2022. "New York Great Lakes Wind Energy Feasibility Study," NYSERDA Report Numbery 22-12. Prepared by the National Renewable Energy Laboratory, Advisian Worley Group, and Brattle Group/Pterra Consulting. nyserda.ny.gov/publications

(b) Regulatory/Permitting Approvals

The 2012 Lake Michigan Offshore Wind Advisory Report prepared by the Illinois Department of Natural Resources includes a list of local, State, and federal agencies that would likely have regulatory or permitting requirements that apply to an offshore wind project in Lake Michigan.[499] In addition to permitting requirements from the IDNR, the report also identifies:

- Illinois Environmental Protection Agency
- Local governments and counties
- U.S. Army Corps of Engineers
- The United States Environmental Protection Agency
- The US Fish and Wildlife Service
- Federal Aviation Administration
- United States Coast Guard, Department of Homeland Security
- National Oceanic and Atmospheric Administration
- Illinois Commerce Commission
- Illinois Power Agency

The roles of the Department of Natural Resources, the Illinois Environmental Protection Agency, the Illinois Commerce Commission, and the Illinois Power Agency are all considered in HB 2132, while the other entities listed are not.

The Lake Michigan Offshore Wind Energy Advisory Council Report recommended that "the [Illinois State] legislature should adopt authorizing legislation that clarifies the authority of the Department to develop a phased approach to leasing the bed of Lake Michigan for offshore wind energy development."[500] The current mechanics of offshore wind permitting were not outlined in that report and there has been no the legislation enacted since that time that would establish what the permitting process of the lakebed would entail.

The Lake Michigan Offshore Wind Advisory Council Report recommended the following criteria to be used in establishing rights for lakebed leasing.

[499] https://dnr.illinois.gov/content/dam/soi/en/web/dnr/documents/lmowefinalreport62012.pdf.

[500] IDNR, 2013

Table 6-2: Lake Michigan Offshore Wind Advisory Council Report Proposed Lakebed Lease Criteria

(1) Environmental Factors:
(a) Visual Impacts–- *No unreasonable interference with residential, business, recreational and tourism-related shoreline uses. The State may also consider enhanced standards for protected shorelines*.
(b) Fish Spawning Areas/Refuges–- *No unreasonable impact on existing fish spawning areas or refuges.*
(c) Waterbird Nesting, Resting and Feeding Areas – *No unreasonable impact on shoal and shallow water areas used by ducks, geese and other waterbirds.*
(d) Reef–- *No unreasonable impact on existing reef structures.*
(e) Threatened or Endangered Species and their habitat–- *Compliance with State and Federal endangered species laws and other laws designed to protect specific natural resources*.
(f) Migratory Flyways of Birds and Bats – *Compliance with Federal laws designed to protect migratory birds and bats and no unreasonable impacts to migratory birds.*
(g) Avian Nesting, Feeding and Resting Areas–- *No unreasonable impacts to avian nesting, feeding and resting areas, including migratory species and winter residents.*
(h) Geology and Sediments–- *Suitable geologic conditions exist to support the long-term installation of off-shore wind energy turbines and other associated equipment or facilities and the installation of off-shore wind energy turbines will not adversely affect lake ice formation and sediment transport processes.*
(i) Benthic and Aquatic Habitats–- *No unreasonable impacts to benthic and aquatic species and their habitats, including avoiding introductions of non-native species.*
(j) Terrestrial Ecology–- *No unreasonable impacts to terrestrial species or habitats.*
(k) Electrical and Magnetic Fields–- *No unreasonable impacts to benthic and aquatic species and their habitats.*
(l) Acoustic Impacts–- *No unreasonable acoustic impacts to people, avian, benthic or aquatic species during construction and operation.*
(m) Available Wind Resources–- *Suitable wind resources to provide economic justification for installation of offshore wind energy facilities.*
(2) Marine Factors:
(a) Recreational Boating–- *No unreasonable impacts to recreational boating on Lake Michigan.*
(b) Historical/Archeological/Shipwrecks/Cultural Resources–- *Compliance with State and Federal cultural resource protection laws.*
(c) Sport and Commercial Fishing–- *No unreasonable impacts to sport and commercial fishing in Lake Michigan.*
(d) Other Existing Uses–- *No unreasonable impacts to other existing and lawful uses of Lake Michigan.*
(3) Public Infrastructure:
(a) Electrical Transmission equipment–- *Transmission equipment must connect to the transmission grid in accordance with all federal, state and local laws, ordinances and other requirements.*
(b) Water Supply Infrastructure–- *No unreasonable interference with existing water supply infrastructure and equipment.*
(c) Littoral Zone–- *No unreasonable impacts to littoral zone erosion or accretion processes.*
(d) Other Public Infrastructure–- *No unreasonable impacts to existing public infrastructure and equipment.*
(e) Feasibility – *Acceptable and appropriate design and construction methodologies, equipment, and timeframes.*
(4) Transportation/Security:
(a) Recommended Shipping Lanes–- *No unreasonable impacts to recommended shipping lanes.*
(b) Federal Aviation Administration/Air Transportation–- *Compliance with all State and federal air transportation laws and regulations*

d) Modeling Results

As discussed in Chapter 4, the Agency conducted four different modeling exercises to assess the impacts on generation, transmission, electricity prices, and the overall economy of each policy proposal. The models used were:

- GE MARS to evaluate the impacts on generation reliability and resource adequacy (conducted by GE Energy Consulting)
- Siemens PTI PSS®E and PowerGEM TARA to evaluate the impacts on transmission reliability and grid resilience (conducted by ENTRUST Solutions Group)
- Aurora production cost simulation to evaluate the impacts on electricity prices and generation related emissions (Conducted by Levitan and Associates)
- IMPLAN to evaluate the impacts on the State's economy including job creation (Conducted by Levitan and Associates)

Full reports of each modeling exercise are available as Appendices B to E of this Study, and Chapter 8 provides a detailed overview of the results of each model. This section provides key results for the proposed offshore wind procurement.

i) Generation Reliability and Resource Adequacy

Generation Reliability and Resource Adequacy are measured through two criteria, Loss of Load Expectation ("LOLE"), and Effective Load Carrying Capability ("ELCC"). Each were studied in 2030 and 2040 to evaluate impacts over time. The industry standard for LOLE is 0.1 days/year (which can also be thought of as one loss of load event in ten years). This is the baseline against which adding the proposed policy is studied to see if that level increases or decreases.

ELCC measures the resource's ability to produce electricity when the grid is most likely to experience a loss of load event and is expressed as a percentage of a resource's total capacity. This provides a way to assess how the generation technologies examined for a given policy can be relied on to prevent a loss of load event. The value of this criteria is that it provides context for the significance of the contribution of the resource. Any resource that can contribute a level of capacity during high-risk loss-of-load probability[501] hour will have a higher capacity value (ELCC) than resources that can deliver the same capacity *only* during low-risk loss-of-load probability hour.

The proposed offshore wind project studied has a limited impact on generation and resource adequacy. In both 2030 and 2040, when modeled against a baseline backdrop of 0.1 LOLE, the LOLE would be expected to change from 0.1 to 0.09. This decrease in LOLE is less than the impact seen by the other two policy proposals that were studied. This less significant decrease is due to the smaller size (in MWs) of the proposed offshore wind project in HB

[501] The "loss of load probability" concept is used by grid operators to determines the percent chance or odds that there will be a situation when available generation capacity is less than the system load demand . By dictating an ELCC value to a generation asset the grid operator can estimate how well the grid will perform during a loss of load event.

2132 compared to the HVDC proposal, or the deployment of energy storage proposed in SB 1587. Similarly, the ELCC for offshore wind is expected to be 29% in 2030 and 20% in 2040. These levels are also lower than the other policies studied and decrease over time due to the changing generation mix in the State. The shift in LOLE is the result of load and resource mixes changing over time. That change can explain part of the downward trend in ELCC.

Overall, an offshore wind project similar to that proposed in HB 2132 is estimated to have a small, positive impact to generation reliability and resource adequacy.

ii) Transmission Reliability and Grid Resilience

Transmission reliability and grid resilience are modeled for this Policy Study by analyzing potential power flow changes resulting from the proposed policy. In considering the power flow analysis, a key portion of the examination is how the proposed policy highlights the need for upgrades to the transmission system to be able to support increased injection amounts (in MW) onto the grid. As generation resources are added to the grid, existing overloaded grid conditions or constraints can increase, and new overloads or constraints can be created.[502] While the analysis conducted for this policy study identified likely transmission upgrades that would likely be needed, these are only estimates. Actual costs would be determined by the completion of full interconnection studies by the applicable RTO. This power flow study is meant to broadly estimate interconnection costs.

The results of the power flow analysis are expressed in total dollar cost to represent the magnitude of the investment needed to accommodate new interconnection for the policy studied. Results are also expressed on a dollars per megawatt basis to better compare costs between different types of projects and proposals.

For the offshore wind project as outlined in HB 2132, when analyzing transmission reliability and grid resilience, it is important to note that any proposed offshore wind project in Lake Michigan would still be in early phases of development, and there has been no determination of a proposed point of interconnection for the wind project to connect to the transmission grid. Therefore, in this analysis, five different potential interconnection points in the Lake Calumet area of Chicago were modeled.[503] The five points are relatively similar in projected interconnection costs. The results of the analysis estimated that for a potential offshore wind project, the Stateline 138 kV substation may be the most suitable primary point of interconnection.

For offshore wind, the estimated interconnection costs are generally higher than the estimated cost per megawatt of interconnection costs incurred by the HVDC proposal or by the utility-scale energy storage proposal. The offshore wind power flow modeling results and ELCC results shows minimal positive impact on grid resilience. It is important to note

[502] These constraints are referred to as violations, and the goal of transmission upgrades is to remove the likelihood of the violations occurring.

[503] For additional details on these potential interconnection points, please see Appendix B.

that the Agency only modeled network upgrade costs, and did not include the costs for the physical connection of the project (facilities costs).

Table 6-3: Potential Interconnection Costs

Point of Interconnection	Cost of Network Upgrades ($MM)	Cost of Network Upgrades ($/MW)
Stateline 138 kV	$331.2	$1,656,000
Calumet 138 kV	$369.6	$1,848,000
North Harbor 138 kV	$369.6	$1,848,000
Stateline 345 kV	$450.5	$2,252,500
Calumet 345 kV	$390.9	$1,954,500

Based on the current status of PJM Transition Cycle #1, Transition Cycle #2, and Cycle #1 in PJM's interconnection review process, it is not possible at this point to accurately determine the cost allocation of network upgrades for a project that will be studied as part of Cycle #1. For this reason, in the modeling the project had 100% of the network upgrades cost allocated to it. Since this modeling is only a feasibility study, it is too early to accurately determine the project's cost allocation as that allocation is normally conducted at the System Impact Study phase. As other projects enter and withdraw from the generation queue and network upgrades for those projects are developed, the cost responsibility for future projects will become clearer. Most network upgrades assigned to the offshore wind project will be allocated to other generation interconnection projects, resulting in a reduction of the costs allocated to the offshore wind project.

iii) Impact on Electricity Costs

To estimate the impact from each policy proposal on electricity costs, the Aurora model was used. Aurora is a model that runs production cost simulations of the electric system. Production simulation models are widely used in the power industry as a tool to estimate the cost of electricity from the generation resource analyzed. Aurora achieves this by running a simulation of operation of generation and transmission systems under user-specified assumptions using forecasts for electricity demand, fuel prices, and anticipated generation resource mix and operating performance. The Aurora model of the proposed offshore wind project shows it has the potential to impact electricity costs in several ways.[504]

First, HB 2132 would authorize an increase in the RPS rate cap from 4.25% to 4.5% which is roughly equivalent to $33-34 million per year (actual amounts depend on retail electricity

[504] The costs and emissions reduction results presented in this section have been revised from the draft Policy Study to reflect several corrections in modeling. The most significant revisions include those described in the Agency's February 8 errata that updated the reporting of energy revenue, and revisions made after receiving comments on the draft Policy Study that include updating retirement schedules for certain plants, adopting an adjustment to the capacity price for the ComEd zone, and including the investment tax credit for the proposed offshore wind project. For details on those corrections please see Section 8.d.i.

sales; based on forecasts of retail sales, a range of $33-$35 million annually seems likely) paid by retail electric customers through the same surcharge presently used to fund RPS expenditures. Second, Aurora modeling results estimated that the revenue received from capacity and energy sales, and the sale of RECs, is less than the revenue necessary to support the project. One reason why market revenues are project to be low is that the capacity market benefits for offshore wind are limited due to offshore wind having a low Unforced Capacity ("UCAP") contribution. A UCAP contribution is the MW value of the resource as cleared in the capacity market, compared to the nameplate value or Installed Capacity ("ICAP"). The results of the Aurora modeling are an estimated annualized shortfall in 2022 dollars of $10.6 million, which suggests that for the project to be viable, the proposed increase in the RPS rate cap may be insufficient to support the project.

Additionally, the estimated electricity cost impacts used in the modeling are a reflection of current market expectations and constraints. The status of available offshore wind technology and currently available information and assumptions could improve over time. For example, NREL's Advanced Technology Scenario is more optimistic about future costs. For the purpose of the modeling conducted for this Policy Study, the Agency chose technology that is currently feasible for Great Lakes offshore wind based on the NREL Baseline case. Capital and operating costs could decline more rapidly than the conservative case assumed than the NREL Annual Technology Baseline used in this analysis. Market conditions in late 2023 and early 2024 highlight recent pressures from inflation and the supply chain issues impacting renewable energy development, which have been leading to increased costs in contrast to historical trends. This has led to increased costs that developers are faced with and increase the likelihood of renewable project cancellations in the short term. These project cancellations or delays may abate in the future.

A third impact on energy costs includes benefits: the project would benefit ratepayers by impacting wholesale energy costs, lowering those costs for Illinois ratepayers by $301.6 million over 20 years, or $8.9 million on an annualized cost in 2022 dollars.

For the average Ameren residential customer, the modeling indicates that the monthly bill impact from 2030-2040 of implementing the offshore wind policy would be $0.39 in nominal dollars and $0.25 in real 2022 dollars. For the average ComEd customer the impact would be $0.25 in nominal dollars and $0.16 in 2022 real dollars. The difference between the Ameren and ComEd bill impacts is due to the lower average consumption of ComEd customers compared to Ameren customers. For more information on these comparisons, see Section 8.d.ix.

iv) Impact on Emissions

The production cost simulation estimates emissions abatement that could be created from electricity generated by the combustion of fossil fuels in the absence of additional renewable generation modeled by each policy proposal. Emissions from the combustion of fossil fuels—specifically, particulate matter ("$PM_{2.5}$"), sulfur dioxide ("SO2") and nitrogen oxides (nOx)—

are linked to a wide range of adverse health effects and carbon dioxide (“CO_2”) emitted by the combustion of fossil fuels, contributes to climate change. Table 6-4 contains the avoided emissions projected from the proposed offshore wind project over a 20-year period from 2030 to 2049.

Table 6-4: Offshore Wind Emissions Impacts (2030-2049)

CO_2 (Tons)	CO_2 (tons/MWh)	SO_2 (Tons)	SO_2 (lbs./MWh)	NO_x (Tons)	NO_x (lbs./MWh)	$PM_{2.5}$ (Tons)	$PM_{2.5}$ (lbs./MWh)
7,488,714	0.55	-137	-0.02	-129	-0.02	21	0.00

In the draft study, one fossil unit was mis-identified as being located in Illinois. For this final study, that classification has been corrected, but as a result the emissions profile for the base case and the policy cases has changed. Specifically, the criteria pollutant emissions are only calculated for plants located in Illinois, since those pollutants have effects on a local level, while CO_2 emissions from the entire region are included because the impacts of CO_2 emissions are felt across geographies. In the offshore wind case, the incremental additional generation capacity offered by the offshore installation replaces out-of-state fossil-based baseload generation, but also results in an increased use of in-state fossil-based “peaker” plants. Peaker plants can be ramped up or down quickly to respond to changes in available baseload intermittent generation, like wind, providing short-term generation to meet any gaps when demand is high but there is no wind generation. Existing peaker plants often emit more criteria pollution than baseload natural gas plants.

Modeling changes were made to correctly retire gas-fired power plants that were not correctly flagged to convert to Zero Emissions Facilities. Retirement of several nuclear facilities outside of PJM was also corrected to match age-out input assumptions. These changes resulted in reduced baseload power available and utilized within Illinois to balance the intermittency of offshore wind in the corrected modeling. This results in a small increase in criteria pollutant emissions in the OSW case due to the increased utilization of in-state peaker plants, with mostly out-of-state baseload fossil generation being reduced. Since the emissions impact calculation does not consider out-of-state criteria pollutant emissions, that reduction does not offset the increased utilization of in-state peaker plants.

As described in more detail in Chapter 8, estimating the dollar impact of avoided emissions reductions is a complex and uncertain exercise, and the range of estimates can have a ten-fold span. Chapter 8 summarizes recent literature on emissions costs. This includes a range of CO2 prices based on the Social Cost of Carbon established by the Interagency Working Group in 2016, and more recent estimates developed by the U.S. EPA that are currently under consideration. Based on those ranges, an estimate of the monetized value of the avoided emissions reductions from the proposed offshore wind project over the 20-year are shown in Table 6-5.

Table 6-5: Offshore Wind Range Emissions Impacts (2030-2049, Shown in 2022 Real Dollars)

CO_2	\$116 million - \$1.138 billion
SO_2	-\$1 – -\$5 million
NO_x	-\$2 million -\$0
$PM_{2.5}$	\$0 - \$3 million

v) Economic Impacts

The economic impacts and job creation modeling was conducted using IMPLAN, a modeling tool used widely in many industries. A set of inputs are entered into the IMPLAN model and the software generates results that include estimates of output, value added, and jobs created. If deemed necessary, the capital and operating expenditures include high and low values to reflect a range of uncertainties contained in the inputs into the model. The results are reported in both total dollar amounts and as a function of the size of the project (MW) and the energy output (\$/TWh). Job creation is reported as Fulltime Equivalents in Illinois (e.g., one FTE is 2,080 hours of work, which could all occur in one year, or be spread out across several years) and expressed as both totals and as a function of the size of the project and the energy output.

The total value added[505] and total employment impacts from a proposed offshore wind project as outlined in HB 2132 is estimated below.

Each proposed policy analyzed in this Policy Study varies in not only the magnitude of resources added to the grid (in MW); they also vary significantly in the magnitude of economic impact. This means that the resulting employment and value-added impacts cannot be directly compared between the policies. A one-to-one comparison between the different proposals would be misleading. For example, while the utility-scale energy storage proposal shows significantly greater employment and value added than the other cases analyzed, that proposal also has an economic impact that is orders of magnitude larger—energy storage of 7,500 MW compared to offshore wind's 200 MW.

[505] The total effects are the sum of the direct, indirect and induced effects.

Table 6-6: Total (Direct, Indirect, and Induced) Value Added

Case	Total Value Added		
	$	$/MW	$/TWh
Offshore Wind Low CapEx	$61,144,172	$305,721	$4,473,504
Offshore Wind High CapEx	$153,688,671	$768,443	$11,244,358
Offshore Wind Low OpEx	$36,676,720	$183,384	$2,683,387
Offshore Wind High OpEx	$111,436,228	$557,181	$8,153,033

Table 6-7: Total (Direct, Indirect and Induced) Job Creation

Case	Total Job Creation		
	FTE-years	FTE-years/MW	FTE-years/TWh
Offshore Wind Low CapEx	484	2.418	35.378
Offshore Wind High CapEx	1,121	5.603	81.990
Offshore Wind Low OpEx	281	1.404	20.548
Offshore Wind High OpEx	772	3.861	56.493

The proposed 200 MW offshore wind pilot project is small in comparison to the size of other North American offshore wind developments, such as those on the East Coast, which involve thousands of MW of turbines. Therefore, the employment impacts associated with this project, especially those that would involve onshore port support facilities, will be limited since the size of the pilot project might not justify significant investment in large port facilities to service the project. It is also unlikely that any of the turbine components would be manufactured in-state, unless there are already existing in-state facilities that manufacture parts that will be used in the turbines. IMPLAN, as run for this analysis, does not provide sufficient granularity to break out the employment by trade. Nor does IMPLAN break out the employment that would result from the port service facilities, but the IPA estimates that this employment is likely to involve less than 150 FTE-years for 20 years of operation. This estimate is consistent with the port services operations related employment estimated for a 400 MW fixed-bottom offshore wind project in Lake Erie by the New York State Energy Research and Development Authority (NYSERDA), which when scaled for the 200 MW Lake Michigan offshore wind pilot project would be 110 FTE-years.[506] If the pilot project proves to be successful and leads to the development of significant offshore wind capacity in Lake Michigan, then the port facility employment impact would be increase commensurately.

[506] NYSERDA Report 22-12, "Great Lakes Wind Energy Feasibility Study," December 2022. This report also provided an estimate of the construction related employment effects for the Lake Erie port support facilities. Scaled to the Lake Michigan project, the employment impacts would total 226 FTE-years based on a 3-year construction period for the port facilities. The IPA cautions that this estimate of construction related employment is highly uncertain depending on location specific conditions which are likely to differ considerably between the proposed site of the Lake Erie project and the proposed site of the Lake Michigan project.

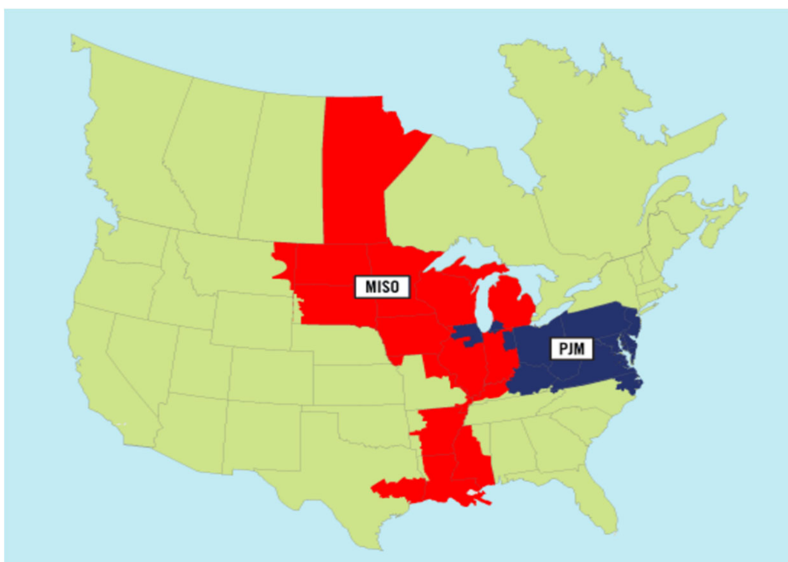
7) High Voltage Direct Current Transmission Line

a) Transmission Planning in Illinois Introduction and Overview

This section first covers transmission planning efforts in Illinois and then delves into the transmission planning approach taken by the overseeing RTOs in Illinois (MISO and PJM). The next part of this section discusses merchant transmission, an independent transmission development approach used by transmission developers such as SOO Green. This section explains how transmission initiatives by both the state of Illinois and the RTOs are implemented and how merchant transmission line development exists within the State's regulatory structure.

In 1997, Illinois started the process of deregulating its electricity market—separating generation, transmission, and distribution activities. This was a shift away from the previous vertically integrated electric utility model. Meanwhile FERC Order No. 2000, issued in late 1999, led to the voluntary creation of RTOs whose responsibilities are to administer the transmission grid on a regional basis.[507] Presently, transmission planning in Illinois is now managed by two RTOs, MISO and PJM. ComEd is in PJM's territory, while Ameren and MidAmerican are in MISO territory. Both MISO and PJM oversee planning and expansion of the transmission infrastructure to relieve congestion and enhance grid capacity within their territories.[508]

Figure 7-1: MISO and PJM territories



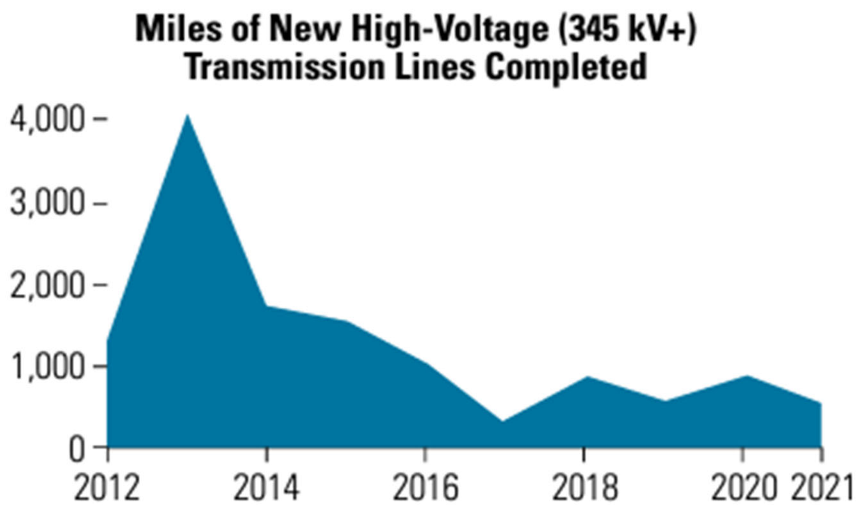
Source: MISO and PJM

[507] Federal Energy Regulatory Commission. (n.d.). *RTOs and ISOs*. https://www.ferc.gov/power-sales-and-markets/rtos-and-isos

[508] More information about RTO responsibilities can be found at Mesa Solutions. (2023, August 24). *ISO and RTO in deregulated markets*. https://247mesa.com/unveiling-iso-and-rto-deregulated-markets/

While transmission planning in Illinois is mostly managed by the RTOs, achieving the clean energy goals set by CEJA will likely require improved transmission efforts by both the state of Illinois and the RTOs. A recent report by DOE stresses the need for a collaborative approach by federal agencies, state and local governments, and other stakeholders to meet the clean energy goals.[509] According to DOE, the nation will need to expand transmission systems by 60% by 2030 and may need to triple those systems by 2050 to meet the growing clean electricity demands. Transmission line buildout is recognized as one of the areas needing improved joint effort from all levels of the government.

Figure 7-2: High Voltage Transmission Development



Source: U.S. Department of Energy Office of Policy

Currently, there are no active HVDC transmission lines in Illinois. The SOO Green Transmission Line[510] and the Grain Belt Express Line[511] are the most recent HVDC transmission lines proposed to interconnect into the Illinois electricity grid. However, the Grain Belt Express Line has faced delays for over 10 years.[512] The Grain Belt line is not proposed to be an underground HVDC transmission line and thus is not within the scope of the policy to be studied pursuant to Public Act 103-0580. The discussion of the Grain Belt line is contained in this chapter to provide context on HVDC transmission lines, as the Grain Belt line has been extensively debated in Illinois and will be familiar to policymakers.

[509] See more information on the report at Department of Energy. (n.d.). *Queued up… but in need of transmission*. Energy.gov. https://www.energy.gov/policy/queued-need-transmission

[510] SOO Green. (n.d.). SOO Green HVDC Link. Retrieved December 15, 2023, from https://soogreen.com/

[511] Grain Belt Express. (n.d.). Retrieved December 15, 2023, from https://grainbeltexpress.com/

[512] Find more information at Utility Dive. (2023, March 31). *DOE study highlights America's transmission needs, but how do we accelerate buildout?* https://www.utilitydive.com/news/doe-study-transmission-clean-energy/646589/

Additionally, CEJA included new Section 8-512 of the PUA,[513] directing the ICC to prepare a Renewable Energy Access Plan ("REAP").[514] The REAP is a forward-looking plan that focuses on transmission reliability and reducing transmission system congestion within Illinois and the regional transmission organizations serving Illinois. The goals of the REAP include preventing limitations of Illinois' existing and new carbon-free electric generation facilities, including renewable energy resources and zero emission facilities, so that they may serve Illinois' public policy goals to achieve 100% renewable energy by 2050 and achieve an affordable and equitable system for Illinois electricity customers.

The REAP is also consistent with FERC Order No. 1000, which requires RTOs to plan for transmission system needs in line with state public policies and to accept input from states during the transmission system planning processes.

The ICC, in conjunction with the Brattle Group and Great Lakes Engineering, published the first draft of the REAP in July 2022, and released an updated first draft in August 2022.[515] After 120 days of public comment and workshops hosted by the ICC and the Brattle Group to gather more information, a second draft REAP was released in December 2022.[516] The ICC initiated an investigation with an Order on December 15, 2022 to develop and adopt a REAP. The investigation is underway,[517] and by December 31, 2025, and every other year thereafter, the ICC must open an investigation to develop and adopt an updated REAP that, at a minimum, evaluates the implementation and effectiveness of the plan, recommends improvements to the plan, and provides changes to transmission capacity necessary to deliver electric output from the REAP zones.

i) Transmission Planning in PJM and MISO

This section provides background on the different approaches taken by MISO and PJM in transmission planning to improve grid reliability.

(1) Transmission Planning in PJM

PJM conducts an annual transmission planning study called the Regional Transmission Expansion Plan ("RTEP").[518] This annual plan identifies transmission system upgrades and improvements to the operational, economic, and reliability requirements of PJM's service area. PJM's region-wide RTEP approach integrates transmission with generation and load response projects to meet load-serving obligations. Further, PJM's annual plan summarizes

[513] 220 ILCS 5/8-512.

[514] Illinois Commerce Commission. (2022). *Renewable energy access plan*. https://www.icc.illinois.gov/informal-processes/Renewable-Energy-Access-Plan

[515] https://www.icc.illinois.gov/informal-processes/Renewable-Energy-Access-Plan

[516] https://www.icc.illinois.gov/downloads/public/informal-processes/renewable-energy-access-plan/2022-12-15-final-second-draft-illinois-renewable-energy-access-plan.pdf

[517] https://www.icc.illinois.gov/docket/P2022-0749

[518] PJM. (n.d.). *Regional transmission expansion planning*. PJM Learning Center. https://learn.pjm.com/three-priorities/planning-for-the-future/rtep

the studies that help ensure the transmission system meets reliability requirements, market efficiency, resilience, public policy, and the needs of the transmission system owners.

Throughout the year, the RTEP process facilitates planning updates and seeks to resolve issues through open and transparent engagement with members, stakeholders, regulatory agencies, and other parties. Through the Transmission Expansion Advisory Committee ("TEAC") forum, PJM staff members and stakeholders exchange ideas, discuss study assumptions, and review results. This subregional RTEP committee also addresses local planning concerns.

PJM's RTEP planning process covers two 18-month study cycles for reliability that overlap by six months and one 24-month study cycle for market efficiency. Market efficiency projects are designed to reduce congestion on the transmission system to help ensure that the lowest-priced power can be delivered across the grid. Currently, PJM applies planning and reliability criteria over a 15-year horizon to identify transmission constraints and other reliability concerns. The 15-year horizon allows PJM to evaluate the need for larger transmission projects long before construction. Transmission projects that develop from PJM's RTEP process fall into several categories, namely Baseline Projects, Network Upgrades, Supplemental Projects, and Intermediate-Need Reliability Projects.[519]

Baseline Projects ensure compliance with national and regional reliability standards. These projects address issues such as overloads, bus voltage drops, excessive short-circuit current, generator stability, and congestion. After PJM identifies a baseline transmission need, including for market efficiency, PJM may open a competitive proposal window, depending on a project's required in-service date, voltage level, and scope.

Network Upgrades are equipment enhancements needed for new customers seeking long-term transmission service and connection to the grid.

Immediate-Need Reliability Projects solve more urgent reliability violations[520] or system conditions that need to be addressed in three years or less. In Immediate-Need Reliability Projects, time constraints may not allow for a competitive proposal without risking the reliability of the transmission system. As a result, these projects are subject to a competitive exemption and are performed by incumbent transmission owners.

Supplemental Projects are exempt from the competitive bidding process according to FERC rules. These are transmission expansions or enhancements by transmission owners to address local reliability needs, such as customer service and load growth, equipment condition, operational performance and risk, and infrastructure resilience. PJM evaluates these projects to ensure they do not cause reliability concerns on the regional grid.

[519] PJM. (n.d.). *RTEP: Planning for Long-Term Transmission Needs.* https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/rtep-fact-sheet.ashx

[520] Reliability violations are thermal overload violations that are identified on multiple transmission lines and/or transformers.

PJM also engages in interregional planning with its neighbors in other RTOs such New York Independent System Operator ("NYISO") and ISO New England in the Northeast, Midcontinent Independent System Operator ("MISO") in the West, Southeastern Regional Transmission Planning ("SERTP"), and North Carolina Transmission Planning Collaborative ("NCTPC") in the Southeast.[521]

(2) Transmission Planning in MISO

MISO maintains reliability in the grid by conducting economic, reliability, and short- and long-term studies. The studies examine the present and the future, using different scenarios, to anticipate what could happen in various timeframes within 5 to 40 years. The MISO planning efforts include reliability planning to confirm whether the bulk electric system has enough supply and demand, annual MISO transmission expansion planning ("MTEP"),[522] interregional coordination,[523] long-range transmission planning, and creating scenarios of energy under various conditions.

MISO's MTEP is used to address local, near-term needs through projects that go in service within 3-5 years of approval. Projects that arise in the MTEP process typically fall under categories such as Baseline Reliability Project, Generator Interconnection Projects, Market Efficiency Projects, Market Participant Funded Projects, Multi-Value Projects,[524] Other Projects, Targeted Market Efficiency Projects, and Transmission Deliverability Service Projects.[525]

Projects that target longer-term regional needs of the system are managed through MISO's Transmission Evolution formerly called Long Range Transmission Planning ("LRTP"), one of the pillars under the reliability imperative.[526]

The Transmission Evolution pillar examines the MISO region's future transmission needs and associated cost allocation holistically, including transmission to support utility and state plans for existing and future generation resources. The transmission evolution pillar houses three initiatives:

- Long Range and Interregional Transmission Planning: MISO considers local, regional and interregional transmission planning processes and buildout based on futures which are reflective of resource evolution. This process is standardized to

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[521] PJM. (n.d.). *PJM - Interregional planning*. https://www.pjm.com/planning/interregional-planning

[522] More information on MISO MTEP can be found here at MISO. (n.d.). *MISO Transmission Expansion Plan (MTEP)*. Midcontinent Independent System Operator (MISO). https://www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=

[523] MISO. (n.d.). MISO Interregional coordination. Midcontinent Independent System Operator (MISO). https://www.misoenergy.org/planning/interregional-coodination/

[524] To find out more on MISO MVP check MISO. (n.d.). *Multi-value projects*. Midcontinent Independent System Operator (MISO). https://www.misoenergy.org/planning/multi-value-projects-mvps/#t=10&p=0&s=Updated&sd=desc

[525] More information on MISO MTEP can be found here at Midcontinent Independent System Operator (MISO). (n.d.). *MISO Transmission Expansion Plan (MTEP)*. https://www.misoenergy.org/planning/transmission-planning/mtep/#t=10&p=0&s=&sd=

[526] The reliability imperative refers to the responsibility MISO shares with its members and states in addressing urgent and complex reliability challenges in the MISO region.

enable policy goals and the future grid with broadly accepted cost allocation methodology;

- Planning Transformation: Processes are aligned, to recognize emerging transmission needs (e.g., grid-enhancing technology, fleet evolution, extreme weather). Provides alignment with markets and operations, including automated modeling; and
- Resource Utilization: A resource retirement process is coordinated with stakeholders and informed by key inputs. Processes aim at interconnecting new resources quickly to accommodate an increasing number of resources with smaller MW capacity. Attribute requirements are implemented and monitored throughout resource lifecycles to ensure sufficient generation amidst resource evolution.[527]

These initiatives under the transmission evolution pillar aim to ensure MISO maintains and improves the system's reliability, especially with the ongoing changes in the resource mix of its member states. MISO also engages in interregional coordination with PJM Interconnection, Southwest Power Pool, and the Southeastern Regional Transmission Planning Region to develop mutually agreeable methods for allocating the costs of transmission facilities that benefit more than one region.[528]

b) Merchant Transmission Project Development

A merchant transmission line (or lines) connects to an existing transmission grid. Under this structure, the entire transmission line—from ownership, control, financing, construction, operation, maintenance, and tariff setting—is managed by private developers. The transmission developer or owner is also responsible for the initial cost to purchase the rights-of-way. Additionally, the transmission line owner has some level of discretion on who can access the transmission line.[529]

Despite the private ownership, merchant lines are still subject to technical compliance with the grid code,[530] if there is in place, and regulations in the same manner as all power system assets. This includes approvals on siting/permitting, design, and technology to ensure safety, alignment, and efficiency in the national power system. The extent to which a merchant line is subject to regulation is primarily a function of the regulatory framework of the host jurisdiction(s). The merchant line system is also privately managed and controlled, with the owner/developer determining when to utilize the capacity of the line to transmit power between markets; directing all dispatch, operational, maintenance, and repair

[527] MISO. (n.d.). *Reliability imperative*. Midcontinent Independent System Operator (MISO). https://www.misoenergy.org/meet-miso/MISO_Strategy/reliability-imperative/

[528] Midcontinent Independent System Operator (MISO). (n.d.). *MISO Interregional coordination*. https://www.misoenergy.org/planning/interregional-coodination/

[529] United States Department of Commerce. (n.d.). *Understanding Power Transmission Financing*. cldp.doc.gov/sites/default/files/2021-10/Understanding_Transmission_Financing.pdf

[530] A grid code is a technical specification that defines the parameters a facility connected to a public electric grid has to meet to ensure safe, secure, and economic proper functioning of the electric system.

determinations for the line(s); and negotiating commercial agreements, including pricing, with the transmission systems on either end of the line to secure grid access.

Although merchant line developers pay all their costs to own and develop the line, the expectation is that the transmission line will be able to recuperate costs and obtain profits that exceed the costs of building and operating the line. An opportunity for merchant line developers to recuperate costs plus profits is presented through price arbitrage. In this case, merchant line developers would connect a market that experiences low electricity prices to one that has higher electricity prices and profit from the price arbitrage.

Figure 7-3: Merchant Transmission Line Schematic

Source: The United States Department of Commerce

Another opportunity to recuperate costs is through selling capacity on the line, which is essentially providing a set path for generators and load serving entities to move electricity from one place to another. The merchant line developers open a bidding window for interested customers to negotiate a price for obtaining transmission line capacity. Interested customers can be load serving entities, utilities, generating companies/project developers, or even energy traders. The developers aim to negotiate rates with the interested customers that will exceed the costs to build the line.

Aside from cost concerns, there are some major challenges when it comes to creating and operating a merchant transmission line, including financing the line and location of the line. Transmission projects are capital intensive and may require private developers to finance the project with more equity than debt in a high interest rate environment. This can be challenging given the size of investment dollars required for building transmission assets. Additionally, identifying the right locations that allow for optimal price arbitrage for siting generation assets, transmission routes, and interconnection sites can be a complex process. Further, receiving approvals for the use of these locations can be very time-consuming.

i) Other Merchant Transmission Projects

There are several merchant transmission projects currently under development in the U.S., namely the Sunzia Southwest Transmission project, Transwest Express Line, and Grain Belt Express. Grain Belt Express is an Invenergy HVDC transmission project that is expected to connect four electricity markets; MISO, PJM, Associated Electric Cooperatives, and

Southwest Power Pool.[531] This 800-mile HVDC transmission line is proposed to deliver renewable energy from Kansas to neighboring power pools across the Midwest including Illinois, Indiana, and Missouri. Grain Belt Express has a $7 billion price tag and is estimated to bring in over $942 million in output to the state of Illinois during project construction, and over $7.3 million annually in long-term output.[532]

ii) Similarities Between Grain Belt Express and SOO Green

There are similarities between Grain Belt Express and SOO Green HVDC transmission lines. First, both transmission lines are merchant projects that would be paid for by independent transmission developers. The costs of the Grain Belt Express would be recovered through the customers of the line including local utilities or large power purchasers. In Missouri, Grain Belt Express has signed transmission service agreements with 39 Missouri municipal utilities that are a part of the Missouri Joint Municipal Electric Utility Commission and plans on securing additional customer agreements in other Midwest regions.[533] The SOO Green project is expected to recover costs by participating in the proposed HVDC REC procurement outlined in the draft HVDC legislative proposal analyzed for purposes of this Policy Study, PJM's capacity market, and other avenues.

Another similarity is that both projects are expected to deliver renewable energy into Illinois and across the Midwest. The Grain Belt Express (expected to begin construction in 2025) is expected to bring in electricity generated from wind from Kansas while SOO Green (expected to begin construction in 2024) is expected to bring wind energy from Iowa. Both projects are expected to connect multiple electricity markets, including SOO Green expecting to connect to the MISO and PJM markets, and Grain Belt Express expecting to connect the PJM, MISO, Associated Electric Cooperatives, and Southwest Power Pool markets.

iii) Differences Between Grain Belt Express and SOO Green

One major difference between SOO Green and Grain Belt Express line is the design of the transmission lines. Grain Belt Express is an overhead transmission line while the SOO Green is an underground transmission line. This makes the permitting process and overall cost for both projects vastly different. The SOO Green transmission line is expected to use an existing railroad right-of-way, which should shorten the permitting timeline. Additionally, given that the SOO Green line is an underground transmission line, it should be relatively protected from wildfires, tree branches, or extreme weather conditions. However, one of the major downsides of constructing underground transmission lines is the construction cost. Underground transmission lines are estimated to cost more than overhead transmission lines. A report by the Public Service Commission of Wisconsin states that "the estimated cost

[531] Grain Belt Express. (n.d.). Retrieved December 15, 2023, from https://grainbeltexpress.com/

[532] More information on the grain belt fillings in the ICC can be found at: Illinois Commerce Commission. (n.d.). *Case details for 22-0499*. https://www.icc.illinois.gov/docket/P2022-0499

[533] Grain Belt Express. (n.d.). *Landowners updates*. https://grainbeltexpress.com/landowners/#landowner-faqs

for constructing underground transmission lines ranges from 4 to 14 times more expensive than overhead lines of the same voltage and same distance." However, these cost estimates are contingent on a variety of factors such as right-of-way access, the number of ancillary facilities needed, local environment, and other considerations which defers depending on the transmission line project.[534]

While the Grain Belt Express and the SOO Green transmission line are both transmission projects that are expected to have direct/indirect cost–benefit implications to Illinois residents, these two projects are not mutually exclusive. The HVDC modeling analysis in this study is only for the SOO Green project as the Grain Belt Express line is not proposed to be an underground line.

c) Opportunities and Barriers to HVDC in Illinois

i) Opportunities

To achieve ambitious clean energy goals, more renewable energy will need to be connected to the grid that can then be delivered to Illinois electric customers. Building new transmission lines can help achieve clean energy goals by bringing more renewable energy to the Illinois grid.

According to a DOE report, "[m]any of the best wind and solar resources are not located near existing transmission infrastructure."[535] To access these areas and connect more low-cost renewable energy to the grid, new transmission lines are needed. When there is more energy available in the grid than existing transmission lines can deliver, congestion and bottlenecks may occur. A report by Grid Strategies recorded congestion costs in MISO totaling $3.7 billion and in PJM totaling $2.5 billion in 2022.[536] New transmission lines can reduce congesting and bottlenecks, thus enabling lower-cost energy to be delivered to the consumer.

Most of the transmission lines in the U.S. are high voltage alternating current ("HVAC"), however HVDC lines may offer benefits that are not captured by HVAC lines.[537] In the HVDC line, the current flows in one direction which results in less power loss than in the HVAC line where voltage and current oscillate and experience more power loss. Over long distances, HVDC line losses can be up to 30-50% lower than comparable HVAC lines.[538] Some of the other notable benefits of the HVDC lines lie in distance and control. Not only can the HVDC

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[534] Public Service Commission of Wisconsin. (n.d.). *Underground Electric Transmission Lines*. psc.wi.gov . https://psc.wi.gov/Documents/Brochures/Under%20Ground%20Transmission.pdf at page 17.

[535] Department of Energy: Office of Policy. (2022, April). *Queued Up… But in Need of Transmission*. Energy.gov. https://www.energy.gov/sites/default/files/2022-04/Queued%20Up%E2%80%A6But%20in%20Need%20of%20Transmission.pdf

[536] Grid Strategies. (2023, July). *Transmission Congestion Costs Rise Again In U.S. RTOS*. https://gridstrategiesllc.com/wp-content/uploads/2023/07/GS_Transmission-Congestion-Costs-in-the-U.S.-RTOs1.pdf

[537] EE Power. (2022, October 19). *The Benefits of High-Voltage Direct Current (HVDC) Power*. https://eepower.com/technical-articles/the-difference-that-dc-makes/#

[538] Department of Energy: Office of Electricity. (2023, September 27). *Connecting the country with HVDC*. Energy.gov. https://www.energy.gov/oe/articles/connecting-country-hvdc

lines transmit significantly more power over longer distances than HVAC lines, but HVDC lines also provide fast and accurate control of the power flowing within the system.

Building out HVDC transmission lines may also support multiple forms of market development. For example, there is growing demand for power to serve data centers, and existing dispatchable resources are retiring. Therefore, new renewable resources are being developed that could increase investment opportunities for HVDC transmission developers. DOE highlights data centers as one of the most energy-intensive building types—consuming 10 to 50 times more energy than an average commercial office building with the same footprint.[539] The surge in data center establishments may require additional transmission systems to accommodate the increased energy demand.[540] A notable example is in Virginia's Loudoun County, where Dominion Energy (the primary power provider in the county) faces transmission constraints. These constraints are leading to delays in the construction of new data centers in the area.[541] Another example is Chicago, which is one of the biggest markets in the U.S. for hyper-scale data centers.[542] Additional transmission may be needed in Illinois to support the growing energy demand prompted by data centers. Additionally, a study conducted by Brattle Group estimates that electrification of transport and home heating will add approximately $3-7 billion per year of transmission needs over the next decade.[543] This estimate increases to $7-25 billion per year for 2030-2050.

There are federal funding programs available to developers looking to build out HVDC transmission lines. DOE's Grid Resilience and Innovation Partnership Program offers grants totaling $10.5 billion.[544] Additionally, DOE's Transmission Facilitation Program offers an additional $2.5 billion funding.[545] These programs are funded by the Bipartisan Infrastructure Law and aim to improve grid flexibility and resiliency of the power system.

Another initiative geared toward transmission facilitation is the IRA. Under Section 50151 (Transmission Facility Financing) of the IRA, $2 billion is appropriated for a direct loan program for certain transmission project development.[546] This funding will remain available

[539] Department of Energy: Office of Energy Efficiency & Renewable Energy. (n.d.). *Data centers and servers*. Energy.gov. https://www.energy.gov/eere/buildings/data-centers-and-servers

[540] McKinsey & Company. (2023, January 17). *Investing in the rising data center economy*. https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/investing-in-the-rising-data-center-economy

[541] Data Center Frontier. (2023, May 30). *The power problem: Transmission issues slow data center growth*. https://www.datacenterfrontier.com/energy/article/33005221/the-power-problem

[542] Fox News. (2024, January 1). *Demand for digital services gives rise to hyperscale data centers*. https://www.foxnews.com/us/demand-digital-services-gives-rise-hyperscale-data-centers

[543] More information can be found here: Brattle. (2021, June 1). *Transmission Investment Needs and Challenges*. https://www.brattle.com/wp-content/uploads/2021/10/Transmission-Investment-Needs-and-Challenges.pdf

[544] Department of Energy: Grid Deployment Office. (n.d.). *Grid resilience and innovation partnerships (GRIP) program*. Energy.gov. https://www.energy.gov/gdo/grid-resilience-and-innovation-partnerships-grip-program

[545] Department of Energy: Grid Deployment Office. (n.d.). *Transmission facilitation program*. Energy.gov. https://www.energy.gov/gdo/transmission-facilitation-program

[546] Environmental Defense Fund and Sabin Center for Climate Change Law. (n.d.). *IRA section 50151 - Transmission facility financing*. Inflation Reduction Act Tracker. https://iratracker.org/programs/ira-section-50151-transmission-facility-financing/

until September 30, 2030. To be eligible for a direct loan, a transmission project would need to be in a National Interest Electric Transmission Corridor ("NIETC").[547] NIETCs are geographic areas where electricity limitations, congestion, or capacity constraints are adversely affecting electricity consumers and communities. On December 19, 2023, DOE's Grid Deployment Office released the final guidance on the NIETC designation process and opened the first window for public submission of information and recommendations on NIETC designation.[548] The guidance outlines a four-part process DOE is employing to independently identify potential NIETCs.

Table 7-1: Four Phases of NIETC Designation Process

Action	Date
Phase 1: Guidance Issuance Date; Opening of Phase 1 Information Submission Window	December 19, 2023
Phase 1: Close of Phase 1 Information Submission Window	February 2, 2024
Phase 2: Estimated Date for Issuance of Preliminary List of Potential NIETC Designations; Opening of Phase 2 Information Submission Window	Spring 2024
Phase 2: Estimated Date for Closing of Comment Period on Preliminary List of Potential NIETC Designations and Phase 2 Information Submission Window	Spring/Summer 2024
Phase 3: In-Depth NIETC Evaluation and Preparation of Draft Designation Report(s) and NEPA Draft Environmental Document, As Needed	TBD
Phase 4: Final Designation Report(s) and NEPA Environmental Document, As Needed	TBD

Source: U.S. Department of Energy Grid Deployment Office

[547] Department of Energy: Grid Deployment Office. (n.d.). *National interest electric transmission corridor designation process.* Energy.gov. https://www.energy.gov/gdo/national-interest-electric-transmission-corridor-designation-process

[548] More information on the four phases of the NIETC designation process could be found at: Department of Energy: Grid Deployment Office. (2023, December 19). *NIETC Designation Process Final Guidance.* DepartmentofEnergy. https://www.energy.gov/sites/default/files/2023-12/2023-12-15%20GDO%20NIETC%20Final%20Guidance%20Document.pdf at page 30

The preliminary list of potential NIETC designations is expected to be released in the spring of 2024.

Additionally, under Section 50152 (Grants to Facilitate the Siting of Interstate Electricity Transmission Lines) of the IRA, $760 million is appropriated to remain available through September 30, 2029 for grants aimed at facilitating certain onshore and offshore transmission line siting.[549] This section is for relevant siting authorities to receive grants for conducting transmission project studies and examining alternative siting corridors. Grants under this section would be contingent on the siting authority agreeing to make a final decision (approval or denial) on the transmission project within two years.

Lastly, IRA Provision 50153 (Interregional and Offshore Wind Electricity Transmission Planning, Modeling, and Analysis) provides $100 million in funding for offshore wind and interregional transmission analyses and convenings.[550] These federal funding opportunities could help in advancing HVDC transmission studies and HVDC transmission line development in Illinois.

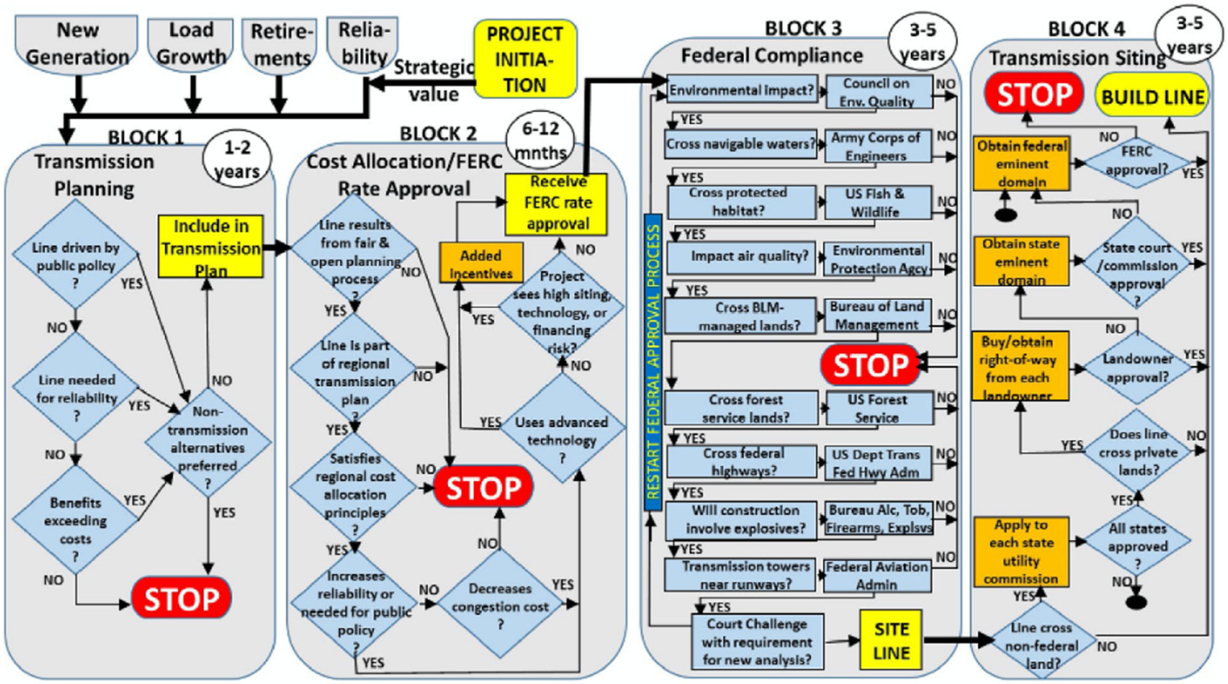
ii) Barriers

Building new transmission lines can be difficult, time consuming, and involve a tedious transmission approval process. Some common buildout challenges include line ownership, siting and permitting lines, and cost allocation across regions. This section covers the major barriers facing HVDC transmission infrastructure buildout.

[549] Environmental Defense Fund and Sabin Center for Climate Change Law. (n.d.). *IRA section 50152 - Grants to facilitate the siting of interstate electricity transmission lines.* Inflation Reduction Act Tracker. https://iratracker.org/programs/ira-section-50152-grants-to-facilitate-the-siting-of-interstate-electricity-transmission-lines/

[550] Environmental Defense Fund and Sabin Center for Climate Change Law. (n.d.). *IRA section 50153 - Interregional and offshore wind electricity transmission planning and development.* Inflation Reduction Act Tracker. https://iratracker.org/programs/ira-section-50153-interregional-and-offshore-wind-electricity-transmission-planning-and-development/

Figure 7-4: Transmission Approval Process



Source: Breakthrough Energy

(1) Interconnection Barriers in PJM and MISO

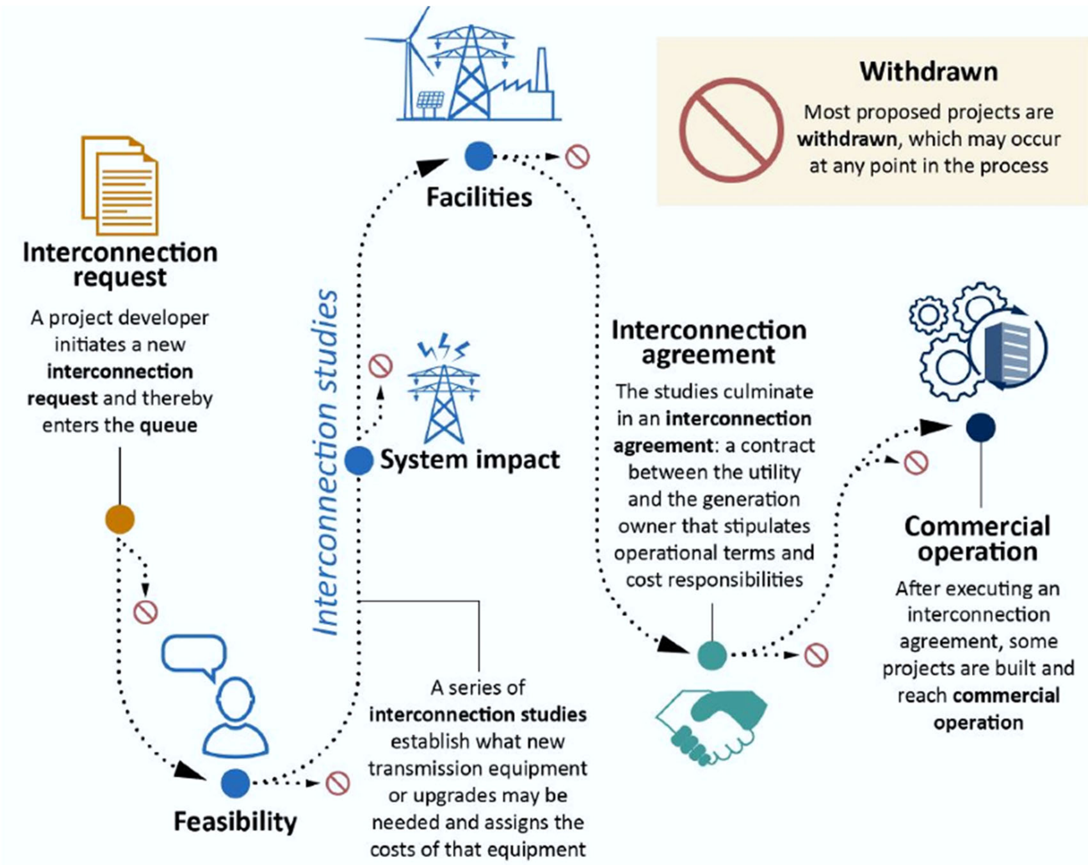
The RTO/ISO interconnection queue delays and costs present a major barrier to HVDC transmission facilitation. PJM and MISO operate wholesale markets across the eastern and midwestern U.S. and receive numerous interconnection applications. Given states' RPS targets and the interest in developing new projects spurred by the IRA, the volume of interconnection requests has significantly increased. According to DOE's Interconnection Innovation Exchange (i2X) report, PJM's interconnection queue nearly quadrupled between 2017 and 2021, bringing the total capacity of projects in the queue to 288 GW—with approximately another 40 GW added in 2022.[551] Similarly, the capacity in MISO's interconnection queue nearly tripled between 2017 and 2021. Interconnection study results are taking longer than expected due to the spike in the interconnection queue. According to a Berkeley Lab report, interconnection wait times averaged five years in 2022, up a year from the average of four years for projects built between 2018 and 2022.[552] The interconnection study is a necessary step for every new generator hoping to connect to the grid.

[551] Department of Energy: Office of Energy Efficiency and Renewable Energy. (n.d.). *Tackling high costs and long delays for clean energy interconnection*. Energy.gov. https://www.energy.gov/eere/i2x/articles/tackling-high-costs-and-long-delays-clean-energy-interconnection

[552] Berkeley Lab. (n.d.). *Queued up: Characteristics of power plants seeking transmission interconnection*. Electricity Markets and Policy Group. https://emp.lbl.gov/queues

Further, for a capital-intensive project like a HVDC transmission line, these delays affect agreements or contracts made by developers and commercial operation date estimates which could lead to financing challenges.

Figure 7-5: Interconnection Queue Process



Source: Derived from image courtesy of Lawrence Berkeley National Laboratory and used with permission. | GAO-23-105583

The interconnection costs both in the MISO and PJM markets are another rising area of concern for HVDC developers. Transmission projects, such as merchant transmission projects, that are initiated outside of RTOs have interconnection costs to connect the proposed transmission lines to the existing electric grid. In DOE's i2X report, DOE found that in PJM territory, average costs for projects that completed studies between 2020 and 2022 had doubled compared to similar projects between 2017 and 2019.[553] MISO also saw doubled costs for projects completed between 2019 and 2021 compared to projects from before 2019. These numbers have increased significantly for projects that remain in the queue, with MISO seeing costs triple and PJM seeing an extraordinary 800% cost increase for active applications in the last two years.

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[553] Department of Energy: Office of Energy Efficiency and Renewable Energy. (n.d.). *Tackling high costs and long delays for clean energy interconnection*. Energy.gov. https://www.energy.gov/eere/i2x/articles/tackling-high-costs-and-long-delays-clean-energy-interconnection

Recognizing the need for change, on June 28, 2023, FERC issued a new rule called Final Interconnection Rule or FERC Order No. 2023 to reform the interconnection process used by RTOs, ISOs, and transmission providers.[554] Previously, interconnection requests were studied on a "first-come, first-served" basis. However, with FERC Order No. 2023, interconnection requests will be studied on a "first-ready, first-served" cluster basis. This approach ensures that only ready projects can enter and proceed through the interconnection queue. Additionally, stricter financial conditions and site control requirements will be put in place to ensure that only ready interconnection customers put in interconnection requests, thus discouraging projects that are merely speculative. Transmission organizations will also face penalties if interconnection studies are not completed on time (with certain exceptions). The compliance deadline is set for April 3, 2024.

Although interconnection reforms are underway, the effectiveness of the reforms is yet to be seen. Currently, rising costs coupled with interconnection study delays have been cited as significant barriers for renewable energy and transmission line developers.[555]

(2) Regulatory Issues and Permitting

Various authorizations, reviews, and permits at the federal, state, and local levels must be completed before a transmission line can begin construction. These three layers of authorization can be a challenging and time-consuming process for interstate transmission development.[556]

At the federal level, transmission lines crossing federal lands are required to obtain right-of-way permits from the relevant land management agencies. Each of the agencies issuing the right-of-way permits operate under different statutory mandates. The information and decision criteria used by the agencies also tend to differ. In addition to right-of-way permits, high-voltage transmission projects commonly require various other federal authorizations and reviews. Merchant transmission developers may also need to obtain an additional permit to operate as a public utility within each of the states where they will be operational. Denial of the permit in one of the state's transmission line routes means the project cannot be built within that state.

At the state level, various permits and authorizations need to be cleared before HVDC transmission line construction. A certificate of public convenience and necessity ("CPCN"), or a similar permit, may be required for a HVDC transmission line to be constructed and operated within the state. In Illinois, the ICC has the authority to grant a CPCN. In other states,

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[554] Federal Energy Regulatory Commission. (n.d.). *Explainer on the interconnection final rule.* https://www.ferc.gov/explainer-interconnection-final-rule

[555] Pv magazine. (2022, February 14). *Interconnection delays and costs are the biggest barrier for utility-scale renewables, say developers.* pv magazine USA. https://pv-magazine-usa.com/2022/02/14/interconnection-delays-and-costs-are-the-biggest-barrier-for-utility-scale-renewables-say-developers/

[556] Federal Energy Regulatory Commission. (2020, June). *Report On Barriers And Opportunities For High Voltage Transmission.* https://www.congress.gov/116/meeting/house/111020/documents/HHRG-116-II06-20200922-SD003.pdf

the CPCN-granting authority differs between the state's public utility commission, another agency, or a board such as a state corporation commission, a dedicated energy siting board, or a combination of agencies. The purpose of the CPCN is to determine whether the projects are in a state's public interest. States often have different and inconsistent criteria for public interest determinations which can make interstate transmission construction increasingly difficult for developers.

SOO Green has obtained the necessary approval in Iowa (see Section 7.d.i.3d)(3) for more information on that regulatory approval process). In Illinois, Section 1-10 of the IPA Act includes a definition of "high voltage direct current transmission facilities" that includes a provision in that definition that requires that, "the system does not operate as a public utility, as that term is defined in Section 3-105 of the Public Utilities Act."[557] The definition also includes a requirement that the facility, "is capable of transmitting electricity at 525kv with an Illinois converter station located and interconnected in the region of the PJM Interconnection, LLC." While it appears that the intention of this provision is to apply to SOO Green (as the proposed Grain Belt line would not meet these qualification), additional clarity through proposed legislation could clarify if SOO Green needs to obtain a CPCN.

Additionally, for interstate transmission projects, the requirement to receive approval from each state through which the project is routed creates a significant barrier. States mostly consider the intrastate benefits and costs rather than the regional benefit of the proposed transmission project. This makes it difficult for interstate transmission developers to receive approvals where intrastate benefits may be low.

At the local level, transmission line developers need to obtain zoning permits where the filing requirements, review processes, and decision criteria for many of these permits vary based on the locality.

(3) Economic Barriers

HVDC transmission lines are capital-intensive projects often with costs as in the billions of dollars. In vertically integrated states with no supervising RTO, utilities own energy infrastructure and initiate transmission development. However, a deregulated state like Illinois has its own method of operation. In a deregulated state, transmission directives are managed by independent transmission companies, merchant transmission developers, or the RTOs. Entering a market characterized by high capital expenses with little or no certainty of cost recovery can create a barrier for new independent transmission companies or merchant developers.

Another economic barrier for multi-state transmission projects is cost allocation. The customer typically ends up paying for the transmission line as part of their electric bill. However, deciding which electricity customers pay for the cost of building and operating a new transmission line that crosses and benefits several states can be a point of

[557] 20 ILCS 3855/1-10.

contention. The Grain Belt Express transmission line exemplifies this concern as it is planned to cross four states. The Grain Belt Express was originally denied by the state regulators in Missouri because the transmission line's benefits were insufficient to justify the cost to the State's ratepayers. Despite the project receiving approval, the resulting delay spanned nearly a decade.[558]

Thus, it could take several months or years for multi-state transmission projects to receive approval due to disagreement on cost allocation amongst the states that the transmission line crosses. In cases where no consensus among the states can be achieved, the project may never be built.

(4) Land Ownership

Land ownership presents another barrier to HVDC transmission line development. Transmission lines crossing through government agencies or property owned by different private landowners need authorization from each landowner before construction can begin. This approval process is often time-consuming, taking years to complete. Landowners may also be opposed to transmission line development for various reasons; one key reason being the compensation paid to the landowner for the use of land. Transmission lines sited near homes are feared to reduce aesthetic and market value of the property.[559] As for agricultural land, transmission line siting may affect farming operations and increase the cost of operating the farm.[560] In cases where the public utility commission or transmission siting authority approves a transmission line, the state has the authority to use the land for public use and pay the landowner compensation. In such cases, landowners may be paid a one-time fee for the line that runs under or above their land, which may be less than the market value of the property.[561] In such cases, affected landowners tend to oppose the proposed transmission line.

Lack of trusting the transmission developer is another reason for landowner opposition to the transmission lines. The landowners' first contact with the development company is often after the CPCN or a similar permit has been granted. However, in Illinois, under Section 8-406.1(a)(3) of the Public Utilities Act. public utilities applying for a CPCN for the construction of any new high voltage electric service line project and related facilities must hold a minimum of three pre-filing public meetings in each county where the proposed project is to be located, no earlier than six months prior to filing the CPCN application.[562] Notice of the

[558] Utility Dive. (2023, March 31). *DOE study highlights America's transmission needs, but how do we accelerate buildout?* https://www.utilitydive.com/news/doe-study-transmission-clean-energy/646589/

[559] Public Service Commission of Wisconsin. (n.d.). *Environmental Impacts of Transmission Lines*. https://psc.wi.gov/Documents/Brochures/Enviromental%20Impacts%20TL.pdf at page 18

[560] Public Service Commission of Wisconsin. (n.d.). *Environmental Impacts of Transmission Lines*. https://psc.wi.gov/Documents/Brochures/Enviromental%20Impacts%20TL.pdf at page 7

[561] Forbes. (n.d.). *Why Landowners Fight Wind And Solar Transmission Lines*. https://www.forbes.com/sites/jonathanfahey/2010/08/12/why-landowners-fight-wind-and-solar-transmission-lines/?sh=49749ebf317e

[562] 220 ILCS 5/8-406.1(a)(3).

public meeting must be published in a newspaper of general circulation within the affected county once per week for three consecutive weeks, beginning no earlier than one month prior to the first public meeting. While this process does not guarantee that each affected individual landowner will attend the public meetings, it does provide a framework for their notification. Further, the affected landowners may not have a long-standing relationship with the developers and therefore may not trust them to be fair in their negotiations. Due to some of these reasons cited above, landowners might join opposition groups to deter transmission development in their local area.

d) Proposed SOO Green Line Process and Structure

i) Overview of Structure

The SOO Green HVDC transmission line is a proposed 2,100 MW underground HVDC merchant transmission project that plans to deliver 13 terawatt hours (TWh) of electricity annually into Illinois.[563] The SOO Green HVDC transmission line has a planned online date of 2029 and is expected to run from the Killdeer, Iowa substation to the Plano, Illinois substation. If approved, the SOO Green transmission line will be the first HVDC line connecting the MISO and PJM regions.[564]

[563] SOO Green. (n.d.). SOO Green HVDC Link. https://soogreen.com/

[564] SOO Green. (2020, May 22). *SOO Green HVDC Link*. https://www.pjm.com/-/media/committees-groups/committees/mrc/2020/20200522-hvdc/20200522-item-03-soo-green-hvdc-link-presentation.ashx

Figure 7-6: Proposed SOO Green Line

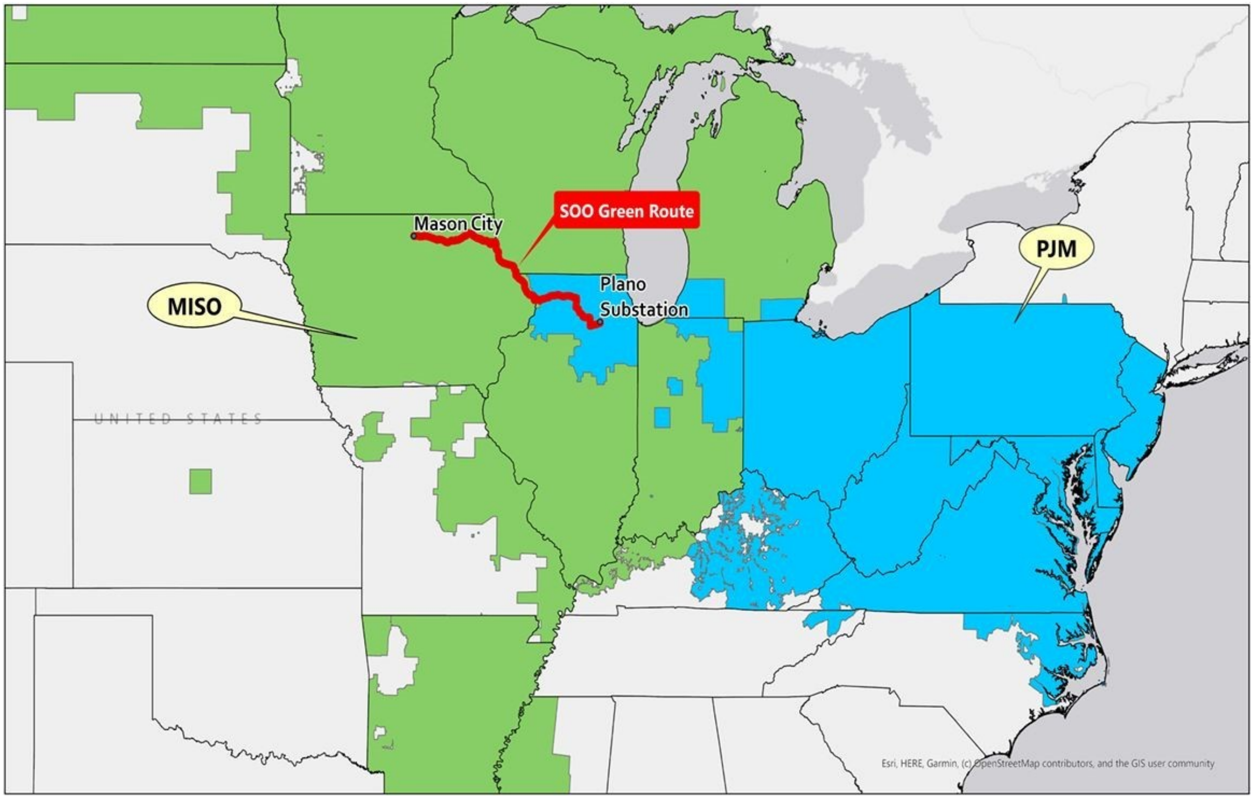


Table 7-2: Other SOO Green Properties

SOO Green Line Details	Properties
Route Distance	350 miles underground, alongside the Canadian Pacific Railway and other corridors
Transmission Technology	High-voltage direct current (HVDC) 525 kV Cross(X)-linked Polyethylene (XLPE) cable
Estimated Useful Life	60+ years
Energy Source	Firm energy provided by Iowa wind, solar, and energy storage resources.[565]
Estimated annual energy production	13 TWh (enough to power approximately 1.5 million homes)
Energy delivery	Plano substation (ComEd territory)

[565] Firm energy refers to the portfolio of supply resources that enable a higher average utilization factor and more consistent hourly delivery profile over SOO Green than the output of a standalone intermittent wind or solar resource.

The subsections below go into further detail about the SOO Green transmission project, detailing the construction approach for the line, and the regulatory filings made with PJM and Iowa Utilities Board.

(1) Construction and Use of an Existing Railroad Easement

The SOO Green HVDC transmission line is expected to make use of existing railroad rights-of-way, removing the need for eminent domain in certain areas. This approach also shortens the permitting process, conserves farmland, and eliminates visual impacts of above ground transmission lines.

While SOO Green will make use of existing railroad rights-of-way, permits will be necessary. Some key permits are noted below:

Table 7-3: Necessary Permits and Approvals

No.	Permit/Approval Agency	Description	Status
1.	U.S. Army Corps of Engineers ("USACE")	Section 404 of the Clean Water Act ("CWA") requires a permit to discharge fill or dredged material into "Waters of the United States."	To be applied 18 months prior to start of construction
2.	USACE	Section 10 of the Rivers and Harbors Act requires approvals for the construction of any structure in, over, or under a navigable water.	To be applied 18 months prior to start of construction
3.	USACE	Section 408 of the Rivers and Harbors Act requires permission to alter a Civil Works project	To be applied 18 months prior to start of construction
4.	Iowa Department of Natural Resources	CWA Section 401 Water Quality Certification, Antidegradation and Outstanding State Waters, Floodplain Development Permit, Sovereign Lands Construction Permits	To be applied 18 months prior to start of construction
5.	Iowa Department of Transportation	Iowa Department of Transportation Utilities Accommodation Permit for ROW along Highway 18	Received August 5, 2021
6.	Illinois Environmental Protection Agency	CWA Section 401 Water Quality Certification	To be applied 18 months prior to start of construction
7.	Illinois Department of Natural Resources	Public Water Permit and Floodway Permit	To be applied 12 months prior to start of construction
8.	Illinois Department of Agriculture	Agriculture Impact Mitigation Plan – Submission required for private easements in Illinois	Completed June 28, 2019
9.	Illinois Department of Transportation	Permit to locate Utility within Department of Transportation's ROW	Received October 29, 2020 – May 6, 2020
10.	County	SOO Green anticipates obtaining any necessary permits from each County in accordance with the County's specific ordinances.	To be applied 24 months prior to start of construction
11.	Utilities/Railroads	Crossing Agreements from utilities and railroads will be required. All crossing agreements from Canadian Pacific for railroad right-of-way crossings have been obtained.	To be applied 24 months prior to start of construction

Source: The Iowa Utilities Board

Additionally, SOO Green has proposed an open trench, jack and bore, and horizontal directional drilling approach ("HDD") for placing the transmission lines under sensitive habitats, existing roads, wetlands, or rivers.[566] The open trench approach allows SOO Green to dig an approximately three-foot-wide, five-foot-deep trench, giving the developer access to bury two eight-inch diameter conduits. The trench is proposed to be backfilled, thereby creating a duct bank.[567] When the duct banks are in place, native soil is expected to be replaced and restored, and then crosslinked polyethylene insulated cables are proposed to be passed through the conduits. These installations are not required to have any cooling fluid and after these installations, the trench is expected to remain closed throughout the life of the SOO Green project.

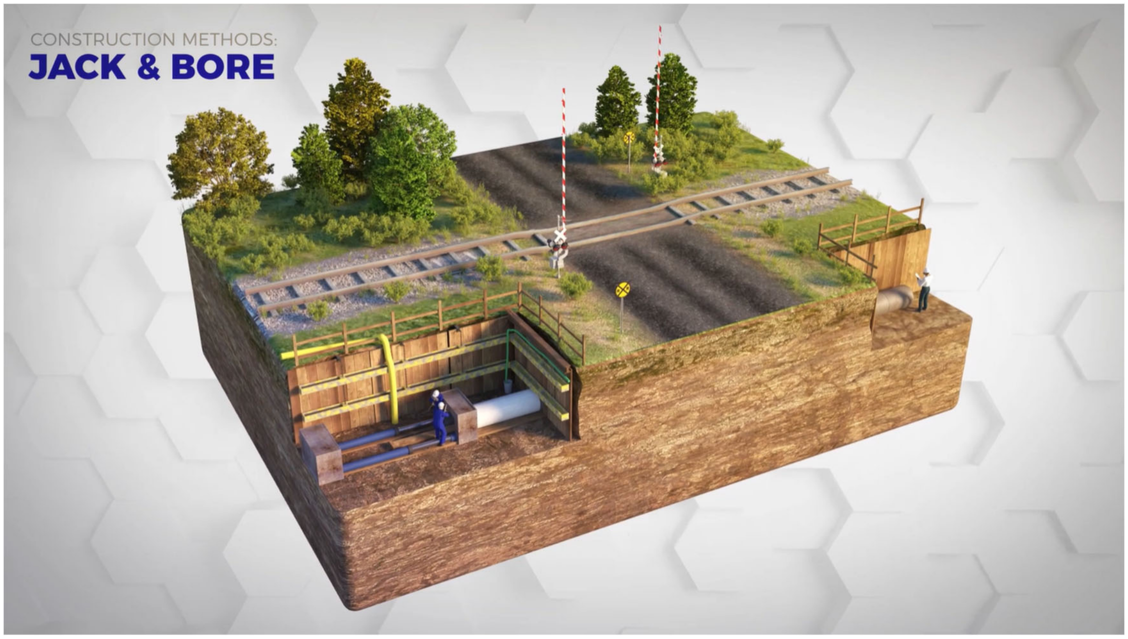
Figure 7-7: Open Trench Approach

Source: SOO Green

[566] SOO Green. (n.d.). *Construction*. SOO Green HVDC Link. https://soogreen.com/construction/

[567] A duct bank is an underground reinforced concrete or metal container used for laying utility lines such as electric cables.

Figure 7-8: Jack and Bore Approach



Source: SOO Green

The jack and bore method is proposed for the portion of SOO Green crossing sensitive habitats, existing roads, or a utility. In this method, SOO Green will bore under the area, placing conduits within a single bore.

Figure 7-9: Horizontal Directional Drilling Approach

Source: SOO Green

SOO Green's proposed HDD approach is for crossing wetlands or rivers, such as the Mississippi River. After drilling and widening the hole, the conduits and casing are typically pulled from one side of the river to the other side. According to the SOO Green developers, the HDD and jack and bore approach can be executed without creating any environmental interruption or surface impacts.

For the construction of the transmission line, SOO Green estimates a three-year development phase and a three-year construction phase.

(2) Regulatory Filings with PJM

SOO Green has filed generator interconnection requests in both MISO and PJM interconnection queues and is currently awaiting interconnection study results.[568]

In the PJM market, a generator can request interconnection service either under an energy resource or a capacity resource service. Capacity Resource status is based on providing sufficient transmission capability to ensure deliverability of generator output to aggregate network load and to satisfy various contingency criteria established by the regional reliability council (e.g., ReliabilityFirst or SERC Reliability Corporation) in which the generator is located.[569] SOO Green has filed to be considered a capacity resource in the PJM market. There have been objections from PJM regarding SOO Green's application to act as a capacity resource.

In September 2021, SOO Green filed a complaint against PJM stating that PJM's external capacity rules were unjust and unreasonable, and proposed an alternative to the external capacity requirements.[570] The following month, PJM filed a response, stating that the alternative proposed by SOO Green was discriminatory and would undermine PJM's ability to maintain reliability. SOO Green also proposed that merchant transmission projects be studied under PJM's RTEP process rather than in the new service request queues. This was another point of contention between SOO Green and PJM. SOO Green claimed that the new service request queues acted as a barrier to entry for emerging merchant transmission projects in the PJM region. PJM rejected this proposal, citing several reasons, one of them being that the RTEP process was borne out of system needs rather than market-driven need.

The IPA is unaware of any additional updates on this matter since March 2022, when PJM urged the commission to disregard SOO Green's request and deny the complaint.[571]

568 PJM Interconnection and Virginia Electric and Power Company. (n.d.). *Interconnection Service Agreement*. https://www.pjm.com/pub/planning/project-queues/isa/o06_dp01_isa.pdf at page 19

569 PJM. (2023, July 26). *PJM Manual 14A: New Services Request Process*. https://www.pjm.com/~/media/documents/manuals/m14a.ashx at page 37

570 More information regarding the docket can be found at PJM. (n.d.). *PJM - Filings & orders*. https://www.pjm.com/library/filing-order.aspx, Docket No. EL21-85-000

571 PJM. (2022, March 1). *Motion To Strike, Or, In The Alternative, Answer Of PJM Interconnection, L.L.C. To Request For Expedited Action On Complaint*. https://www.pjm.com/-/media/documents/ferc/filings/2022/20220301-el21-85-000.ashx

(3) Regulatory Filings with the Iowa Utilities Board

In September 2020, SOO Green filed an application with the Iowa Utilities Board ("IUB") for the right to construct, maintain, and operate the proposed HVDC transmission line in Iowa. The IUB had hearings covering items including project costs, project benefits within Iowa, land rights, and renewable sources in Iowa prior to issuing SOO Green's approval. In September 2023, the IUB issued an order approving the petition.[572] The transmission line will interconnect to the MISO 345kV AC transmission grid at a switching station adjacent to the Killdeer-Colby 345 kV line in Cerro Gordo County. Of the 350-mile SOO Green transmission line, 174 miles will be constructed in Iowa. For this amount of the transmission line in Iowa, approximately 156 miles of the line would be routed through private railroad rights-of-way ("ROW") owned by Canadian Pacific Railway. The remaining 18 miles of the line would route through public road ROW of Iowa Highway 18 in Clayton County.

The SOO Green project costs, including maintenance and system upgrades in either PJM or MISO, will be assigned to SOO Green and cannot be directly passed on to Iowa ratepayers. However, if a load-serving entity in Iowa purchases transmission capacity rights from SOO Green, those costs could be passed on to Iowa ratepayers after the IUB's review and approval.

Regarding project benefits, SOO Green used the IMPLAN economic model to determine the economic benefits of the transmission line, including renewable sources to the state of Iowa.[573] Importantly, the IMPLAN model results presented to the IUB estimated only wind and solar as renewable sources sending power through the transmission line, and did not include energy storage. As discussed elsewhere in this Policy Study, the IPA has employed the IMPLAN model considering wind, solar, and energy storage, as these resources were the generation and storage mix proposed by SOO Green in their responses to the IPA.

According to the model used in the Iowa proceeding, the SOO Green project is estimated to lead to over $663 million in direct capital investment through its transmission construction costs with 5,439 job-years over three years (the project's construction timeline) in Iowa.[574] Additionally, the modeling estimated that the SOO Green transmission line would lead to over $726 million in earnings (wages or salary and benefits) during the construction of the transmission line project, and over $340 million in long-term earnings in Iowa. Regarding the solar and wind energy resources, the modeling estimated that between $1.3 and $1.6

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[572] Iowa Utilities Board. (n.d.). *IUB electronic filing system*. https://efs.iowa.gov/docket/4040264

[573] The results to the IMPLAN study can be found here: Strategic Economic Research. (2023, February). *Economic Impact Analysis of the SOO Green HVDC Link Transmission Project on the State of Iowa*. https:/wcc.efs.iowa.gov/cs/idcplg?IdcService=GET_FILE&allowInterrupt=1&RevisionSelectionMethod=latest&dDocName=2118676&noSaveAs=1

[574] A job-year is one full-time equivalent (FTE) job lasting one year. A full-time equivalent job is one lasting 2,080 hours in a year.

billion in earnings would be obtained from wind and solar component manufacturing and energy construction in Iowa.[575]

In Illinois, according to SOO Green's modeling, the transmission project is estimated to lead to over $386 million in direct capital investment through its transmission construction costs, with 3,810 job-years over the project's construction phase. Economic benefits related to the proposed renewable energy resources providing power to the transmission line would not be realized in Illinois as these resources will be sited in Iowa. The economic benefits realized in Illinois from SOO Green are mainly related to the construction and operation of the transmission line.[576]

Regarding the Voltage Sourced Converter ("VSC") station development in Illinois and Iowa, the facilities are yet to be built. However, SOO Green will purchase major equipment for the converter station overseas. An IMPLAN study conducted by Strategic Economic Research which makes use of cost estimates provided by SOO Green, states "[t]he money spent on converter station equipment won't multiply within the local economy because the spending will flow outside the state."[577] In terms of land rights and eminent domain, as mandated by Iowa law, the SOO Green developers held public information meetings in each county in which the project will be located. The SOO Green developers also provided mailed notice to all landowners who owned property adjacent to the Canadian Pacific ROW and the Highway 18 ROW throughout Iowa. After the public information meetings, SOO Green developers also contacted the necessary landowners to discuss the project. Although SOO Green offered to negotiate a Cooperation Agreement and Mutual Release ("CAMR") with landowners, some landowners refused to sign and filed objections in the IUB docket, thus leading the IUB to grant SOO Green eminent domain over four parcels in Clayton County and two parcels in Dubuque County along the railroad ROW.[578]

Based on disclosures made to the IPA, the energy sources SOO Green proposes to connect to the HVDC line are solar, wind, and battery storage. However, there is no certainty that only renewable electricity will be passed through the line. According to SOO Green, the HVDC transmission line is required by FERC to allow any form of electricity that is generated to be

[575] The results to the IMPLAN study can be found here: Strategic Economic Research. (2023, February). *Economic Impact Analysis of the SOO Green HVDC Link Transmission Project on the State of Iowa*. https:/wcc.efs.iowa.gov/cs/idcplg?IdcService=GET_FILE&allowInterrupt=1&RevisionSelectionMethod=latest&dDocName=2118676&noSaveAs=1

[576] The results of the IMPLAN study conducted by Levitan can be found in the Appendix D.

[577] Strategic Economic Research. (2023, February). *Economic Impact Analysis of the SOO Green HVDC Link Transmission Project on the State of Iowa*.

https:/wcc.efs.iowa.gov/cs/idcplg?IdcService=GET_FILE&allowInterrupt=1&RevisionSelectionMethod=latest&dDocName=2118676&noSaveAs=1 at page 8.

transmitted from one region to another.[579] Therefore, any entity (renewable or non-renewable) that can economically deliver power to the converter station is permitted.[580]

Although the IUB has granted SOO Green state-based approval in Iowa, SOO Green must also receive approval from both PJM and MISO before construction can begin.

ii) Proposed Renewable Resources to be Connected to SOO Green Transmission Line

The SOO Green transmission line's developers plan on connecting three different sources of electricity to feed through the line. Based on information provided to the IPA by SOO Green, these proposed sources are solar, wind, and battery storage. The details of these expected projects are listed below:

- 2,300 MW of West-Central Iowa Wind
- 350 MW of Central Iowa Wind
- 1,850 MW of Central Iowa Solar
- 650 MW of 4-hour battery storage

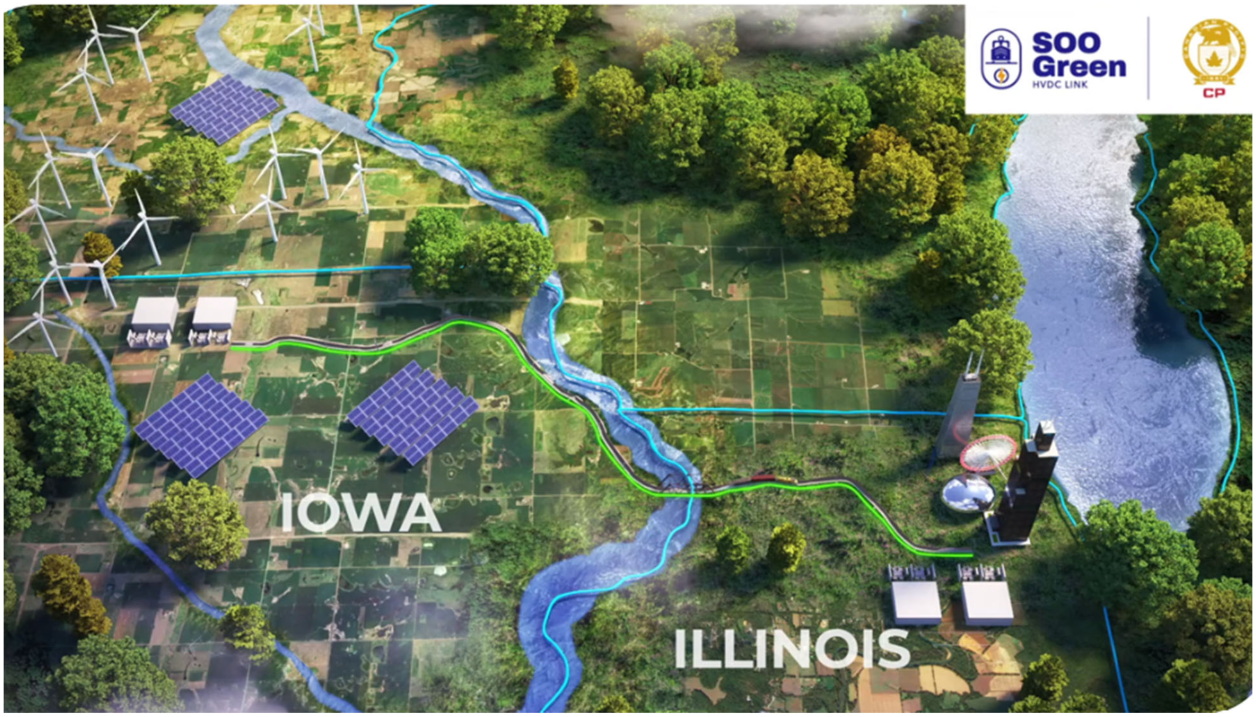
Presently, the renewable sources proposed by SOO Green that connect to the HVDC transmission line and provide energy to Illinois are not yet built. Additionally, the specific locations and attributes of these projects are yet to be identified by the developers. In comments on the draft of this Policy Study, the developers of SOO Green stated that they have signed letters of intent with several project developers for the resources in Iowa, but did not provide any additional details.[581] Additionally, in those comments, the SOO Green developers assert that the resources required to supply the SOO Green line would only represent 44% of the wind, 50% of the solar, and 29% of the battery storage currently in the in MISO interconnection queue for Iowa. Without more information, the Agency was not able to assess the actual availability of planned renewable energy and storage resources in Iowa to supply energy over the SOO Green line. Furthermore, the Agency notes that Minnesota recently enacted ambitious clean energy legislation, and given Minnesota's proximity to northern Iowa, there could be robust competition for energy supplied by from these resources.

[579] Open Access Transmission Tariff: Federal energy Regulatory Commission. (n.d.). *History of OATT reform*. https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform

[580] More information can be found in: https://wcc.efs.iowa.gov/cs/idcplg?IdcService=GET_FILE&allowInterrupt=1&RevisionSelectionMethod=latest&dDocName=2124971&noSaveAs= 1 at page 23

[581] See: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240213-soo-green.pdf at page 23.

Figure 7-10: Visual Imagery of Proposed SOO Green Resources

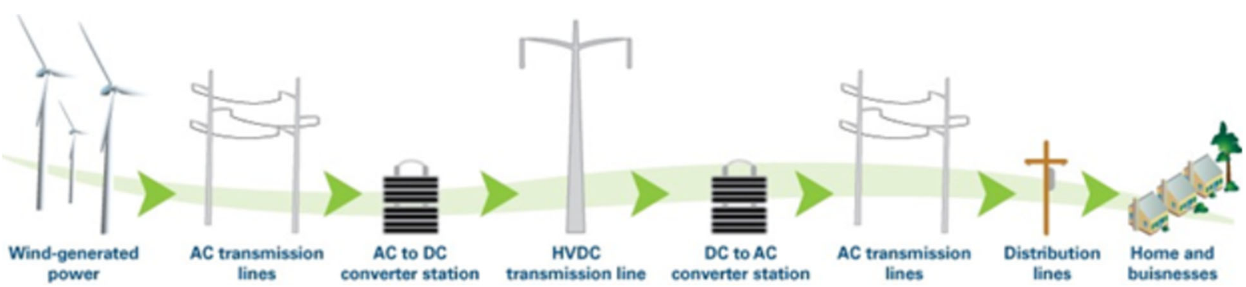


Source: SOO Green

iii) Converter Station Development

The SOO Green developers plan to construct two self-commutated VSC stations at its interconnection points in Mason City, Iowa and Yorkville, Illinois. The Iowa VSC stations will convert Alternating Current ("AC") power produced by renewable sources in MISO to Direct Current ("DC") to enable transmission over the line. Power will then be converted back to AC power at the Illinois VSC for distribution to customers in PJM.[582]

Figure 7-11: HVDC Power Conversion



Source: Duke American via Texas Instruments

[582] To learn more on the difference between AC and DC power, refer to James, L. (2020, March 19). *What's the difference between AC and DC power?* Power & Beyond. https://www.power-and-beyond.com/whats-the-difference-between-ac-and-dc-power-a-0c5c48e598b5e1266e6cebc5731227c2/

The converter stations are necessary to step up voltage to high-voltage DC for long-distance transmission and step down the voltage to lower-voltage AC to be transmitted through local transmission and distribution lines which deliver the power to consumers.[583]

SOO Green is pursuing the necessary approvals and permits from agencies and has yet to begin construction of the converter stations.

e) Environmental Justice Impacts from the Proposed HVDC Transmission Line

The draft legislation for the proposed SOO Green HVDC transmission line will not have a direct impact on environmental justice communities in Illinois. The line would run underground from the Illinois/Iowa border near Savanna, Illinois to a converter station in Plano, Illinois about 15 miles southwest of Aurora, Illinois. There are no environmental justice communities along the route or located in Plano. The closest environmental justice community is in Aurora.[584] Though the Agency has not conducted an analysis to identify the location of environmental justice communities in Iowa, the route of the HVDC transmission line in Iowa would primarily be underground and in rural areas, thus unlikely to affect communities that are disproportionately impacted by pollution. Similarly, the proposed locations of the renewable resources providing energy to the SOO Green transmission line would be in rural areas with smaller populations, thus reducing the impact on environmental justice communities. However, there are indirect ways a project can impact environmental justice communities beyond a direct impact on the built environment. By creating employment opportunities for residents of nearby environmental justice communities, a project could stimulate the local economy and provide opportunities for community investments to help address the historical negative impacts of pollution.

Additionally, to qualify for providing RECs from the proposed HVDC transmission line, the project would need to utilize "high voltage direct current transmission facilities" which include both the line itself and the associated converter station. Based on the definition of high voltage direct current transmission facilities currently contained in Section 1-10 of the IPA Act (adopted in Public Act 102-0662), to qualify, the project developer must enter into a project labor agreement. However, the draft legislation is silent on requirements for minimum equity standards, community benefits agreements, or other mechanisms that could benefit the residents of environmental justice communities. Further, the draft legislation supporting the SOO Green HVDC transmission line does not make any changes to the IPA Act to address equity, environmental justice, or community benefits. Given the absence of any existing or proposed statutory requirements to address the needs of

583 Texas Instruments. (2020, May). *Introduction to HVDC Architecture and Solutions for Control and Protection*. https://www.ti.com/lit/an/sloa289b/sloa289b.pdf?ts=1702479593810&ref_url=https%253A%252F%252Fwww.google.com%252F

584 See https://elevate.maps.arcgis.com/apps/webappviewer/index.html?id=d87a45c18a5c4e0fa96c1f03b6187267 for a map of Environmental Justice Communities in Illinois.

environmental justice communities, there is not a clear policy connection between those needs and the proposed legislation.

In comments on the draft of this Policy Study,[585] the developers of SOO Green noted that the route of the line would pass through several areas in Savanna and DeKalb designated as disadvantaged communities by the federal Climate and Environmental Justice Screening Tool. That tool is not used in the approach for designating communities as Environmental Justice Communities as specified in Section 1-56 of the IPA Act and detailed in the Agency's Long-Term Renewable Resources Procurement Plan.[586] Therefore, for the purposes of this Policy Study, these communities were not considered because Public Act 103-0580 tasked the Agency with examining impacts on Environmental Justice Communities.

The developers of SOO Green also commented that the Agency should consider the impact of SOO Green on localized emissions reductions in Illinois.[587] However, the closure of fossil fuel plants in Illinois is broadly mandated by CEJA and cannot be specifically attributed to the potential development of the SOO Green line.

The developers of SOO Green also requested that the Policy Study include a discussion of a $100 million community investment fund.[588] However, they did not provide additional details, and that community investment fund is not required through the draft legislation used for this analysis. Consequently, consideration of any resulting impacts from that fund is outside of the scope of this Policy Study.

f) Open Questions about the Structure of SOO Green Transmission Line

i) Accreditation

For cost recovery purposes, the SOO Green developers seek to qualify as a capacity resource in PJM's capacity market, the Reliability Pricing Model ("RPM"). There have been considerable objections from PJM in this regard for reliability reasons, and the ability for SOO Green to qualify as a capacity resource in PJM remains an open issue.[589] SOO Green hoped to modify PJM's Open Access Transmission Tariff to permit the HVDC converter stations to qualify as a Capacity Resource. The requirements to participate as an external entity in PJM's RPM auction are: (1) enter a feasible pseudo-tie arrangement; (2) obtain long-term firm transmission service along the entire pathway between the external capacity source and HVDC delivery point in PJM; and (3) enter a written must-offer energy

[585] SOO Green comments at 16-17. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240213-soo-green.pdf.

[586] See Section 8.12 of the 2022 Long-Term Plan. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/modified-2022-long-term-plan-upon-reopening-9-may-2022-final.pdf.

[587] SOO Green comments at 17-19.

[588] SOO Green comments at 20.

[589] United States Of America Before The Federal Energy Regulatory Commission. (n.d.). *Motion For Leave To Answer And Answer Of PJM Interconnection, L.L.C.* https://www.pjm.com/-/media/documents/ferc/filings/2021/20211129-el21-103-000.ashx

commitment with PJM. A pseudo-tie allows the Balancing Authority Area ("BAA") the same level of operational flexibility and visibility of the external resources as it has with internal resources; this gives the BAA the right to make decisions regarding unit commitment, dispatch, and the provision of ancillary services.[590]

Various criteria must be met to enter a feasible pseudo-tie arrangement with PJM, such as the M2M test, electrical distance requirement, Seams Coordination Model Consistency Requirement, and Tagging Assurance and Transfer of Firm Allocation Requirement.[591] SOO Green contends that the pseudo-tie criteria are unnecessary for HVDC controllable external resources and therefore should be waived. PJM ran multiple scenarios showing the reliability risks when SOO Green is not pseudo-tied to the PJM region.[592] In the scenario where there are normal PJM and MISO conditions, or a No Emergency Transmission Loading Relief ("TLR") 5 Event, if SOO Green was pseudo-tied to PJM, there would be no need to be tagged per the North American Electric Reliability Corporation ("NERC") requirements.[593] However, because that is not the case with SOO Green, its resources can only be discharged, at most, every 15 minutes—longer than the present PJM capacity resource (internal and pseudo-tied resources) which can be dispatched every five minutes.

Another scenario used to present the reliability risk was an Emergency TLR 5 Event in PJM and MISO. In this scenario, PJM and MISO are both operating under emergency conditions which results in the necessary curtailment of transactions per NERC requirements. Given the emergency conditions, SOO Green, which is considered a MISO resource, will be subject to curtailment. However, PJM's pseudo-tied resources will be not subject to curtailment via TLR, which gives it a level of firmness that is commensurate with internal PJM capacity resources. According to PJM, "if this external generation resource is hypothetically allowed to qualify as a Capacity Resource, it would be an inferior capacity product compared to existing capacity resources because the tagged transaction can be cut, creating a reliability risk to PJM."[594] PJM makes mention of other drawbacks presented by SOO Green not being pseudo-tied. The case is still pending before FERC.

Another aspect to consider in the SOO Green case is PJM's Effective Load Carrying Capability ("ELCC") construct. To account for variable and limited-duration resource additions into the

[590] More information on pseudo-tie can be found at: PJM. (n.d.). *Dynamic transfers*. https://www.pjm.com/about-pjm/member-services/dynamic-transfers

[591] More information on the pseudo-tie criteria: United States Of America Before The Federal Energy Regulatory Commission. (2021, September 21). *Complaint And Request For Relief Of Soo Green HVDC Link Project Co, LLC*. https://www.pjm.com/-/media/documents/ferc/filings/2021/20210921-complaint-and-request-for-relief.ashx at page 23

[592] United States Of America Before The Federal Energy Regulatory Commission. (n.d.). *Motion For Leave To Answer And Answer Of PJM Interconnection, L.L.C.* https://www.pjm.com/-/media/documents/ferc/filings/2021/20211129-el21-103-000.ashx at page 5

[593] A NERC Tag, also commonly referred to as an E-Tag is used to schedule the transmission of electric power interchange transactions in wholesale markets. An interchange transaction is defined as an agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries as obtained from North American Electric Reliability Corporation (NERC). (n.d.). *Glossary of Terms Used in NERC Reliability Standards*. https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf at page 17.

[594] United States Of America Before The Federal Energy Regulatory Commission. (n.d.). *Motion For Leave To Answer And Answer Of PJM Interconnection, L.L.C.* https://www.pjm.com/-/media/documents/ferc/filings/2021/20211129-el21-103-000.ashx at page 8

grid, PJM and its stakeholders adopted the ELCC method to ensure resource adequacy. PJM employs the ELCC analysis to determine the Accredited Unforced Capacity ("UCAP") value for variable resources (e.g., wind and solar), Limited-Duration Resources (e.g., storage), and Combination Resources (e.g., solar/storage hybrids.[595] Under PJM's ELCC method, a resource that dedicates a significant level of capacity during high-risk hours (i.e., hours with very high electricity demand and low wind or solar output) will have a higher capacity value under ELCC than a resource that delivers the same capacity during low-risk hours. These risk hours may vary as the resource mix changes (e.g., more wind and solar is installed) and hours of high demand evolve (e.g., wide-scale electric car charging at night).[596] Typically, a resource seeking to participate as a capacity resource in PJM must go through the interconnection process and obtain Capacity Interconnection Rights ("CIRs")[597] that determine the amount of energy capacity that the resource can provide to the grid.[598]

Before the adoption of the ELCC method, variable resources received CIRs based on their average summer peak hour capacity factor calculated over the previous three summers. This led to wind and solar resources generally receiving CIRs that reflected a lower percentage of their net maximum capacity when compared to conventional generators whose CIRs were allocated based on their expected peak summer production.[599]

The average ELCC method that was approved by FERC in July 2021 measures the reliability contribution of all ELCC Resources[600] as a portfolio, then class-level ELCC for wind, solar, etc. separately to capture resource diversity benefits.[601] These results are referred to as adjusted class averages.[602]

[595] UCAP reflects the amount of capacity that a resource provides after accounting for its forced outage rate, intermittency, and/or limited output duration capability.

[596] PJM. (n.d.). *Effective Load Carrying Capability Measures Capacity Contribution of Renewables, Storage.* https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/elcc-measures-capacity-contribution-of-renewable-and-storage-resources.ashx

[597] CIRs are "The rights to input generation as a Generation Capacity Resource into the Transmission System at the Point of Interconnection where the generating facilities connect to the Transmission System" obtained from PJM. (2016, May 6). *Capacity Interconnection Rights.* https://www.pjm.com/-/media/committees-groups/task-forces/scrstf/20160506/20160506-item-03-cir-information.ashx#:~:text=Definitions,connect%20to%20the%20Transmission%20System

[598] S&P Global. (2023, April 10). *FERC approves PJM plan to cap capacity values of renewable energy resources.* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/ferc-approves-pjm-plan-to-cap-capacity-values-of-renewable-energy-resources-75135370

[599] S&P Global. (2023, April 10). *FERC approves PJM plan to cap capacity values of renewable energy resources.* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/ferc-approves-pjm-plan-to-cap-capacity-values-of-renewable-energy-resources-75135370

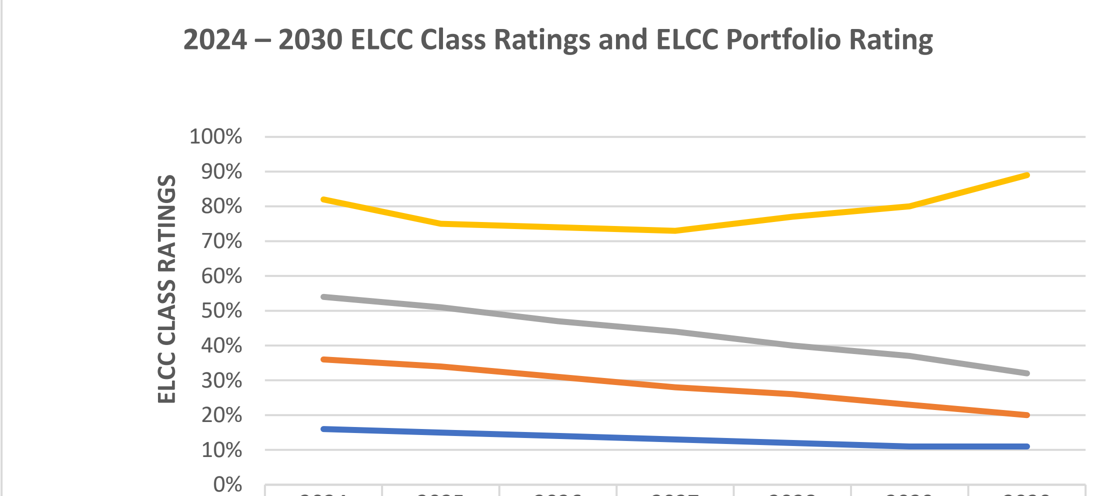
[600] According to PJM, ELCC resource is a Generation Capacity Resource that is a Variable Resource, a Limited Duration Resource, or a Combination Resource. Obtained from PJM. (n.d.). *RAA Definitions Section.* https://www.pjm.com/-/media/committees-groups/task-forces/ccstf/postings/20201030-raa-language-for-filing-clean.ashx

[601] PJM. (2023, January 30). *Members endorse PJM proposal to modify capacity accreditation process for renewable resources.* https://insidelines.pjm.com/members-endorse-pjm-proposal-to-modify-capacity-accreditation-process-for-renewable-resources/

[602] More information can be found at Utility Dive. (2022, June 6). *FERC's acceptance of 2 capacity accreditation methods will complicate renewables development.* https://www.utilitydive.com/news/ferc-capacity-accreditation-renewable-storage-pjm-nyiso/624750/

The adjustments to accredited capacity went into effect in the 2023/2024 Base Residual Auction ("BRA") executed in June 2022, and are shown in Figure 7-12.

Figure 7-12: 2024 – 2030 ELCC Class Ratings and ELCC Portfolio Rating



	2024	2025	2026	2027	2028	2029	2030
Onshore Wind	16%	15%	14%	13%	12%	11%	11%
Solar Fixed	36%	34%	31%	28%	26%	23%	20%
Solar Tracking	54%	51%	47%	44%	40%	37%	32%
4-hour Storage	82%	75%	74%	73%	77%	80%	89%

Source: PJM

In January 2024, FERC approved the PJM proposal to move from its present average ELCC method to a marginal ELCC method that accredits all Generation Capacity Resources and Demand Resources based on their marginal Expected Unserved Energy ("EUE") benefit.[603] According to PJM, shifting to a marginal ELCC approach will lead to selecting "more reliable resources in the capacity market and more efficient capacity price signals that promote resource adequacy at the lowest reasonable cost."[604] The marginal ELCC approach will accredit resources based on their marginal contribution to system resource adequacy across several simulated scenarios given the anticipated resource mix. Additionally, the marginal ELCC approach will exclusively consider resource output in hours of system risk identified after adding the last resource to the expected system portfolio. This approach enables PJM to gain a better indication of which resource types will provide more reliability benefit given the expected system resource mix.

603 PJM explains that EUE measures the expected MWh of load that a system cannot meet (i.e., loss of load measured in MWh) due to resource adequacy insufficiency, while LOLE (PJM's current resource adequacy metric) measures the number of days that are expected to have some level of resource insufficiency, regardless of the duration and magnitude.

604 Federal Energy Regulatory Commission. (n.d.). ELibrary. https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false at page 10

PJM plans to annually reevaluate each resource's marginal ELCC Accredited UCAP. This practice is driven by the fact that a resource's marginal reliability contribution changes due to factors specific to the resource (e.g., maintenance and upkeep) and external factors (e.g., the resource's synergistic and antagonistic relationship with other resources on the system).

PJM aims to implement the marginal ELCC approach in addition with other capacity market enhancements in the 2025/2026 BRA scheduled for June 2024.[605]

Table 7-4: Marginal ELCC Class Ratings for the 2025/2026 Base Residual Auction

ELCC CLASS	2025/2026 BRA ELCC Class Ratings
Onshore Wind	35%
Offshore Wind	60%
Fixed-Tilt Solar	9%
Tracking Solar	14%
4-hr Storage	59%
6-hr Storage	67%
8-hr Storage	69%
10-hr Storage	78%

Source: PJM

PJM has not yet released a long term forecast for the new marginal ELCC method however, given the new ELCC ratings for renewable resources, this will likely impact the compensation SOO Green could receive if it is allowed to participate as a capacity resource in the PJM market.

ii) Construction Impacts

The IMPLAN model results attached in Appendix D provide in-depth analysis of the estimates and inputs for the project construction impacts in Illinois. However, according to studies commissioned by SOO Green, the SOO Green transmission line is expected to have a larger construction impact in Iowa than in Illinois. The three different generating technologies—which are 4-hour battery storage, wind, and solar—will be constructed in Iowa and will connect to the transmission line. These renewable projects sited in Iowa will lead to short-term and long-term job creation, tax revenues, and landowner lease payments that cannot be realized in Illinois. Through the construction of the SOO Green transmission line, the

605 PJM. (2023, October 13). *PJM Files Changes to Capacity Market To Promote Reliability.* chrome-extension://efaidnbmnnnibpcajpcglclefindmkaj/https://www.pjm.com/-/media/about-pjm/newsroom/2023-releases/20231013-pjm-files-changes-to-capacity-market-to-promote-reliability.ashx

modeling conducted by the IPA estimated that Illinois would reap over $238 million in value added (GDP) and state tax revenues of $14 million. Additionally, the construction of the transmission line could lead to a total increase in Illinois state employment of 1,990 FTE-years.[606]

In Iowa, the study commissioned by SOO Green found that the SOO Green transmission line is expected to create or support a total of 5,439 jobs during its three-year construction period. The construction of the transmission line is estimated to increase Iowa's gross state product by over $1 billion and over $726 million in earnings will come to the workers associated with the construction of the transmission line. The transmission line is estimated to lead to Iowa property tax revenues of over $46.1 million for over 30 years. The construction of solar and wind resources in Iowa is estimated to lead to total output[607] that ranges between $3 billion and $4.2 billion, and is estimated to support between 19,683 and 24,030 jobs with total earnings between $1.3 billion and $1.6 billion.[608] While the IMPLAN model does not provide insights regarding employment trades that will be supported through the creation of the SOO Green Transmission line, the Champlain Hudson Power Express (CHPE), a 1,250 MW underground transmission line undergoing construction in New York can be used as a reference in this case. The CHPE contractors Kiewit, NKT, and Hitachi executed project labor agreements (PLAs) with electrical and building trade unions for the line's construction. The PLAs covers 15 different local union chapters across 22 separate trade disciplines some of which are Operating Engineers, Laborers, International Brotherhood of Electrical Workers (IBEW) and Teamsters.[609] To build the converter station in New York, approximately 150 union workers with Kiewit Corporation will work to develop the facility.[610] Given the SOO Green transmission line and the associated renewable resources expected to be connected to the line, it is expected that more trades will be supported through the creation of the line.

g) Comparative Analysis of Proposed SOO Green Legislation and Approaches Taken in Other Jurisdictions to Support HVDC Transmission Development

Different states have different approaches regarding support for transmission line development. States with a regulated electricity market typically leave transmission development to the utilities to oversee—from planning to development—while states with

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606 More information on the IMPLAN results can be found in Appendix D.

607 Output refers to economic activity or the value of goods and services produced in the state or local economy and includes intermediate inputs.

608 Strategic Economic Research. (2023, February). *Economic Impact Analysis of the SOO Green HVDC Link Transmission Project on the State of Iowa* https:/wcc.efs.iowa.gov/cs/idcplg?IdcService=GET_FILE&allowInterrupt=1&RevisionSelectionMethod=latest&dDocName=2118676&noSaveAs=1 at page 8.

609 New York State. (2022, November 30). *Governor Hochul announces start of construction on 339-Mile Champlain Hudson power express transmission line to bring clean energy to New York City*. https://www.governor.ny.gov/news/governor-hochul-announces-start-construction-339-mile-champlain-hudson-power-express.

610 New York State Energy Research and Development Authority. (2023, September 19). *Construction begins on converter station for 339-Mile Champlain Hudson power express.* NYSERDA. https://www.nyserda.ny.gov/About/Newsroom/2023-Announcements/2023-09-19-Governor-Hochul-Announces-Start-Of-Construction-On-Converter-Station-For-339-Mile.

deregulated electricity markets depend on independent transmission line developers or merchant line developers.

New York has a similar electricity market to Illinois, and both states have ambitious climate goals. However, New York's approach to support HVDC transmission in-line advancement is different than Illinois' approach. For example, Illinois' approach included being presented with an HVDC proposal by SOO Green, which could further Illinois' energy goals. New York's approach includes conducting an RFP to examine projects that could advance the State's energy goals.

Further, NYSERDA issued a Tier 4 RFP for renewable energy projects to deliver energy to New York City.[611] NYSERDA received 18 applications, and after a period of screening and scoring, two projects were recommended: the Clean Path NY[612] and Champlain Hudson Power Express.[613] After the selection, the Tier 4 contracts for both projects were negotiated and submitted to the New York Public Service Commission for approval and public comment. These contracts have a 25-year term.

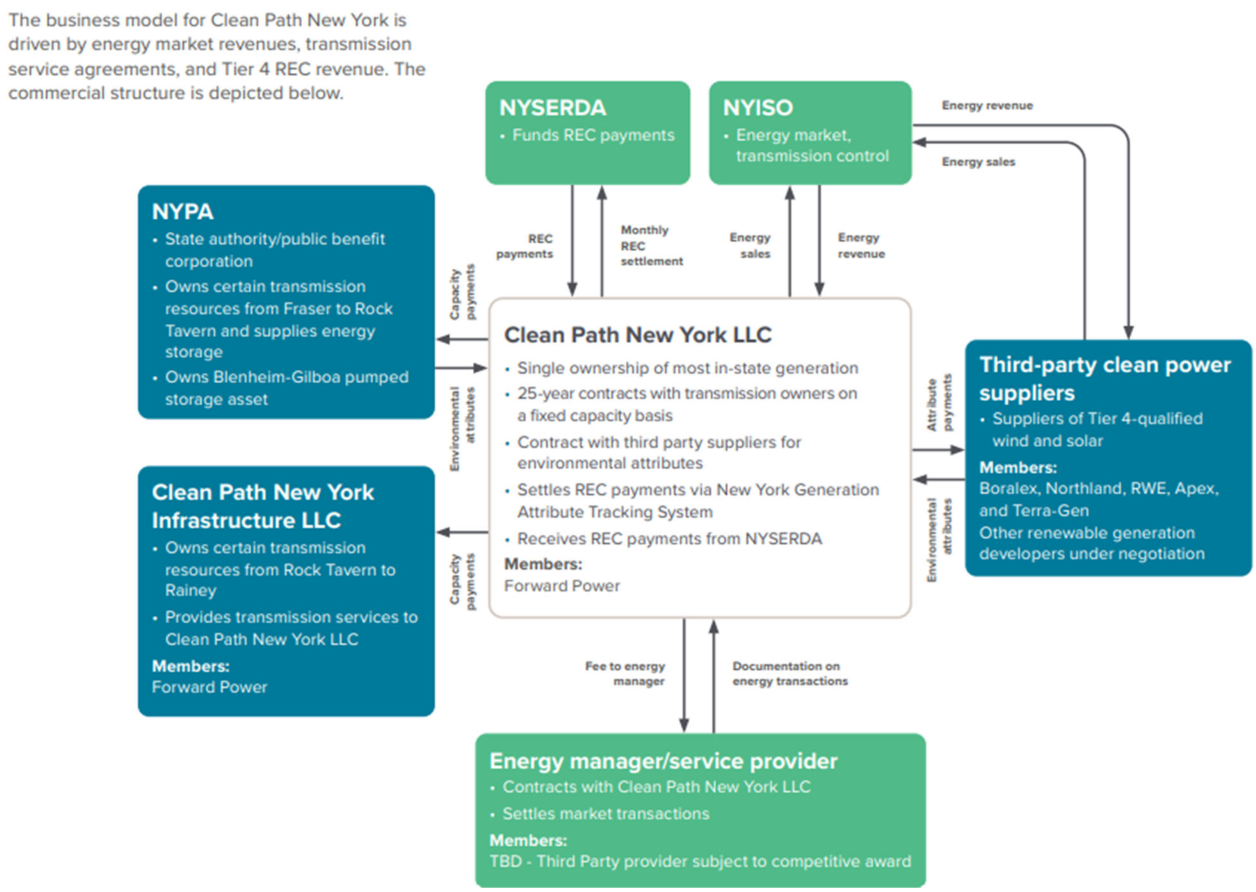
The Clean Path NY developers will recuperate costs through energy market revenues and selling transmission capacity.

[611] New York State Energy Research and Development Authority (NYSERDA. (n.d.). *Tier 4 – New York City renewable energy*. https://www.nyserda.ny.gov/All-Programs/Large-Scale-Renewables/Tier-Four

[612] Clean Path NY. (n.d.). *Clean Path New York | Our Clean Energy Future*. https://www.cleanpathny.com/

[613] Champlain Hudson Power Express. https://chpexpress.com/

Figure 7-13: Clean Path New York Commercial Structure



Source: Clean Path NY

The Clean Path NY project is very similar to the SOO Green project as it is an underground HVDC line that is expected to transport wind and solar energy through the line, firmed by the existing Blenheim-Gilboa pumped storage facility. Additionally, the project will be mostly sited through existing ROWs used by roads and transmission lines. However, it is located entirely within New York state.

By contrast, under the approach proposed in the Illinois HVDC draft bill, the proposed resulting HVDC REC delivery contract would account for the renewable energy that would be transmitted over the HVDC line, with first deliveries commencing on or before June 1, 2029. In addition to REC revenues, the SOO Green project plans on recuperating costs by participating in the PJM market as a capacity resource, selling transmission capacity and through energy market revenues.

The actual commercial structure for the SOO Green line is dependent on factors outside the developer's control (e.g., participating as a capacity resource in the PJM market). Therefore, the structure could change in the future. It is also important to note that the SOO Green model in Illinois is dependent on the proposed sources of electricity (wind, solar, and 4-hour battery storage) participating in the HVDC REC procurement. Presently, the proposed resources that are expected to connect to the transmission line and deliver energy to Illinois are yet to be identified or developed.

h) Modeling Results

As discussed in Chapter 4, the Agency conducted four different modeling exercises to assess the impacts of each policy proposal. The models used were:

- GE MARS to evaluate the impacts on generation reliability and resource adequacy (conducted by GE Energy Consulting)
- Siemens PTI PSS®E and PowerGEM TARA to evaluate the impacts on transmission reliability and grid resilience (conducted by ENTRUST Solutions Group)
- Aurora production cost simulation to evaluate the impacts on electricity prices and generation related emissions (Conducted by Levitan and Associates)
- IMPLAN to evaluate the impacts on the State's economy including job creation (Conducted by Levitan and Associates

Full reports of each modeling exercise are available as Appendices B to E of this Study, and Chapter 8 provides an overview of the methodology used for each. This section breaks out the specific results for the HVDC Transmission line as proposed by SOO Green.

i) Generation Reliability and Resource Adequacy

Generation Reliability and Resource Adequacy are measured through two criteria, Loss of Load Expectation ("LOLE"), and Effective Load Carrying Capability ("ELCC"). Each were studied in 2030 and 2040 to evaluate impacts over time. The industry standard is for LOLE to be 0.1 days/year (which can also be thought of as one loss of load event in ten years). This is the baseline against which adding the proposed policy is studied to see if that level increases or decreases.

ELCC measures the resource's ability to produce electricity when the grid is most likely to experience a loss of load event and is expressed as a percentage of a resource's total capacity. This provides a way to assess how the generation technologies examined for a given policy can be relied on to prevent a loss of load event. The value of this criteria is that it provides context for the significance of the contribution of the resource. Any resource that can contribute a level of capacity during high-risk loss-of-load probability[614] hour will have a higher capacity value (ELCC) than resources that can deliver the same capacity *only* during low-risk loss-of-load probability hour.

The proposed SOO Green transmission line would have an impact on generation and resource adequacy. In 2030, against the backdrop of a 0.1 LOLE level, LOLE would be

[614] The "loss of load probability" concept is used by grid operators to determines the percent chance or odds that there will be a situation when available generation capacity is less than the system load demand . By dictating an ELCC value to a generation asset the grid operator can estimate how well the grid will perform during a loss of load event.

expected to drop from 0.1 to 0, and in 2040, LOLE would drop to 0.01. In other words, against the backdrop of a 0.1 LOLE, the additional resources that SOO Green would bring into Illinois would likely eliminate the expectation of a loss of load event in 2030 and virtually eliminate the expectation in 2040. Similarly, the ELCC for SOO Green would be 96% in 2030 and 92% in 2040, indicating that a significant portion of the energy delivered by SOO Green would contribute to generation and resource adequacy.

Overall, the proposed SOO Green transmission line is estimated to have a positive impact to generation reliability and resource adequacy.

ii) Transmission Reliability and Grid Resilience

Transmission reliability and grid resilience are modeled for this Policy Study by analyzing potential power flow changes resulting from the proposed policy. In considering the power flow analysis, a key portion of the examination is how the proposed policy highlights the need for upgrades to the transmission system to be able to support increased injection amounts (in MW) onto the grid. As generation resources are added to the grid, existing overloaded grid conditions or constraints can increase, and new overloads or constraints can be created.[615] While the analysis conducted for this policy study identified likely transmission upgrades, these are only estimates. Actual costs would be determined by the completion of full interconnection studies by the applicable RTO.

The results of the power flow analysis are expressed in total dollar cost to represent the magnitude of the investment needed to accommodate new interconnection for the policy studied. Results are also expressed on a dollars per megawatt basis to better compare costs between different types of projects and proposals.

For the proposed SOO Green line, these numbers may change significantly as PJM completes the interconnection study process. SOO Green is part of PJM's Transition Cycle #1 and cycles such as Transition Cycle #1, Transition Cycle #2, and Cycle #1 are still a work in progress because of PJM's reform process, and any updated cost for the network upgrades for SOO Green will only be known after the completion of the respective cycle. As the cycles go through decision points and projects either withdraw or enter the queue, the cost of the SOO Green project will become more certain.

Additionally, the ongoing dispute between PJM and SOO Green may influence these costs as the final design of the project and how power flows would be managed remains an open issue.

[615] These constraints are referred to as violations, and the goal of transmission upgrades is to remove the likelihood of the violations occurring.

Table 7-5: Potential Interconnection Costs

Project Size (MW)	Cost of Network Upgrades	Cost of Network Upgrades ($/MW)
2,035	$801.8 million	$394,005

iii) Impact on Electricity Costs

To estimate the impact from each policy proposal on electricity costs, the Aurora model was used. Aurora is a tool that runs production cost simulations of the electric system. Production simulation models are widely used in the power industry as a tool to estimate the cost of electricity from the generation resource analyzed. Aurora achieves this by running a simulation of operation of generation and transmission systems under user-specified assumptions using forecasts for electricity demand, fuel prices, and anticipated generation resource mix and operating performance. The proposed SOO Green Line would impact electricity costs in two ways.[616]

First, based on the 20-year estimate of the revenue the project would receive from capacity and energy sales and an estimated strike price of $115.39/MWh, Aurora modeling estimates a $430.7 million per year difference between expected market revenues and revenues necessary to support the project. This $430.7 million constitutes the annualized cost supported by Illinois ratepayers through the purchase of RECs from the project.

Second, the project would benefit ratepayers by impacting wholesale energy costs, lowering those costs for Illinois ratepayers by $5.85 billion over 20 years, or $178.3 million on an annualized cost in 2022 dollars.

For the average Ameren residential customer, the modeling indicates that the monthly bill impact from 2030-2040 of implementing the high voltage direct current transmission line policy would be $4.99 in nominal dollars and $3.42 in real 2022 dollars. For the average ComEd customer the impact would be $3.21 in nominal dollars and $2.20 in 2022 real dollars. The difference between Ameren and ComEd residential customer bill impacts is due to the lower average consumption of ComEd customers compared to Ameren customers. For more information on these comparisons, see Section 8.d.ix.

To capture the 25-year contract term identified in PA 103-0580, costs, revenue offsets, and energy market impacts were extrapolated to cover the remaining 5-year period (2050-2054). The strike price is presented in nominal level terms. The energy revenue was extrapolated based on the average growth rate over 2045-2049. Capacity revenue was

[616] The costs and emissions reduction results presented in this section have been revised from the draft Policy Study to reflect several corrections in modeling. The most significant revisions include those described in the Agency's February 8 errata that updated the reporting of energy revenue, and revisions made after receiving comments on the draft Policy Study that include updating retirement schedules for certain plants, adopting an adjustment to the capacity price for the ComEd zone, and including the investment tax credit for the proposed offshore wind project. For details on those corrections please see Section 8.d.i.

expected to grow at the rate of cost of new entry ("CONE") escalation (3.5%). Energy market impacts were conservatively extrapolated in the same manner as energy revenue but given that market impacts are greater after retirement of the fossil fleet, the additional impacts estimated are substantial. Clean flows over the line were assumed to be the five-year average across 2045-2049.

Table 7-6: SOO Green Summary Projections, 2030-2054 Contract Period

Case	Costs	Energy Revenue	Capacity Revenue	Net Market Revenues	Energy Market Impact	Total	Energy Output
		$1,000 Nominal					GWh
($1,000 Nominal)	$37,025,252	$12,800,308	$11,105,160	-$13,119,784	$9,268,046	-$3,851,737	320,866
($1,000 2022) - Annualized	$907,502	$301,753	$250,918	-$354,831	$206,814	-$148,017	12,835

ZEFs are Zero Emissions Fuel units included in the Aurora production cost modeling to establish the base case that policy scenarios are compared against. They are called upon sparingly in the Aurora production cost modeling but are critical during stressed system conditions. 8.5 GW of ZEFs are included in the modeling. See Section 8.d.v for more details on the use of ZEFs.[617]

iv) Impact on Emissions

The production cost simulation estimates emissions abatement that could be created from electricity generated by the combustion of fossil fuels in the absence of additional renewable generation modeled by each policy proposal. Emissions from the combustion of fossil fuels—specifically, particulate matter ("$PM_{2.5}$"), sulfur dioxide ("SO2") and nitrogen oxides (NOx)—are linked to a wide range of adverse health effects and carbon dioxide ("CO_2") emitted by the combustion of fossil fuels, contributes to climate change. Table 7-7 contains the avoided emissions projected from the proposed SOO Green line over a 20-year period from 2030 to 2049.

Table 7-7: SOO Green Emissions Impacts (2030-2049)

CO_2 (Tons)	CO_2 (tons/MWh)	SO_2 (Tons)	SO_2 (lbs./MWh)	NO_x (Tons)	NO_x (lbs./MWh)	$PM_{2.5}$ (Tons)	$PM_{2.5}$ (lbs./MWh)
152,660,226	0.59	7,722	0.06	6,172	0.05	975	0.01

[617] ZEFs are Zero Emissions Fuel units included in the Aurora production cost modeling to establish the base case that policy scenarios are compared against. ZEFs are called upon sparingly in the Aurora production cost modeling but are critical during stressed system conditions. 8.5 GW of ZEFs are included in the modeling. See Section 8.d.v for more details on the use of ZEFs.

As described in more detail in Chapter 8, estimating the dollar impact of avoided emissions reductions is a complex and uncertain exercise, and the range of estimates can have a ten-fold span. Chapter 8 summarizes recent literature on emissions costs. This includes a range of CO2 prices based on the Social Cost of Carbon established by the Interagency Working Group in 2016, and more recent estimates developed by the U.S. EPA that are currently under consideration. Based on those ranges, an estimate of the monetized value of the avoided emissions reductions from the proposed SOO Green line over the 20-year are shown in Table 7-8.

Table 7-8: SOO Green Range of Value of Emissions Impacts (2030-2049, Shown in 2022 Real Dollar)

CO_2	\$2.366 - \$23.204 billion
SO_2	\$62 – \$270 million
NO_x	\$14 – \$103 million
$PM_{2.5}$	\$13 - \$118 million

v) Economic Impacts

The economic impacts and job creation modeling was conducted using IMPLAN, a modeling tool used widely in many industries. A set of inputs are entered into the IMPLAN model and the software generates results that include estimates of output, value added, and jobs created. If deemed necessary, the capital and operating expenditures include high and low values to reflect a range of uncertainties contained in the inputs into the model. The results are reported in both total dollar amounts and as a function of the size of the project (MW) and the energy output (\$/TWh). Job creation is reported as Fulltime Equivalents in Illinois (e.g., one FTE is 2,080 hours of work, which could all occur in one year, or be spread out across several years) and expressed as both totals and as a function of the size of the project and the energy output.

The following results are value added and job creation impacts for Illinois.

Table 7-9: Total (Direct, Indirect and Induced) Value Added

Case	Value Added		
	\$	\$/MW	\$/TWh
SOO Green CapEx	\$237,744,695	\$113,212	\$895,056
SOO Green OpEx	\$176,800,517	\$84,190	\$665,665

Table 7-10: Total (Direct, Indirect and Induced) Job Creation

Case	Total Job Creation		
	FTE-years	FTE-years/MW	FTE-years/TWh
SOO Green CapEx	1,990	0.948	7.492
SOO Green OpEx	1,480	0.705	5.571

In contrast, according to filings made by SOO Green before the Iowa Utility Board, the project could create $663 million in capital expenditures in Iowa and 5,439 FTE-years in job creation for the construction of the line. In addition, the development of the renewable resources in Iowa that would supply the line could create an additional $1.3 billion to $1.6 billion in wages and an additional 19,683 and 24,030 FTE-years.

8) Modeling Summaries

a) Introduction

As discussed in Chapter 4, the Agency conducted four different modeling exercises to assess the impacts on generation, transmission, electricity prices, and the overall economy of each policy proposal. These models used were:

- GE MARS to evaluate the impacts on generation reliability and resource adequacy (conducted by GE Energy Consulting)
- Siemens PTI PSS®E and PowerGEM TARA to evaluate the impacts on transmission reliability and grid resilience (conducted by ENTRUST Solutions Group)
- Aurora production cost simulation to evaluate the impacts on electricity prices and generation related emissions (conducted by Levitan and Associates)
- IMPLAN to evaluate the impacts on the State's economy including job creation (conducted by Levitan and Associates)

For generation reliability, resource adequacy, transmission reliability, and grid resilience only utility-scale energy storage systems ("ESS") were modeled as distributed energy storage projects (e.g., paired with residential or commercial solar projects, or with community solar projects) are connected to the distribution system, not the transmission system and thus would not have transmission grid impacts. Because SB 1587 did not propose a level of deployment for distributed energy storage, a proxy 1,000 MW is used in the Aurora and IMPLAN modeling.

Full reports of each modeling exercise are available as Appendices B to E of this Study, and each Chapter on specific Policy Proposals contains a short summary of these results.

b) Evaluation of Resource Adequacy Impact

GE Energy Consulting ("GEEC") was retained by Levitan & Associates, Inc ("LAI"), the IPA's Planning Consultant to assess the impact that each of the policies has on the state's resource adequacy using GE's Multi-Area Reliability Software ("GE MARS"). GEEC's full report is available as Appendix B.

i) Modeling Approach and Input Data Assumptions

To assess the impact the policy proposals would have on system resource adequacy, this study evaluates their capacity value (or firm capacity contribution) and impact to loss of load metrics for the study years 2030 and 2040. Resource adequacy refers to the ability of an electric power system to meet demand for electricity and is a fundamental component of electric system reliability that is assessed through the use of simulation models. The capacity value is measured in terms of Effective Load Carrying Capability (ELCC)[618] and the impact to loss of load is measured in terms of Loss of Load Expectation (LOLE),[619] the industry standard for assessing the impact on reliability.

GE MARS is based on a sequential Monte Carlo simulation,[620] which provides a detailed representation of the hourly loads, generating units, and interfaces between the interconnected areas. In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, as well as deterministic rules and policies, which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods. The random events that this GE MARS simulation analysis considered included: load forecast uncertainties, transmission outages, equipment failures that would interrupt transmission or generation, and variable renewable generation such as when the wind stops blowing unexpectedly.

GE MARS uses state transition rates rather than state probabilities, to describe the random forced outages of thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time and can be used if one assumes that the unit's capacity state for a given hour is independent of its state at any other hour. In contrast, a sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data. In GE MARS, state transition refers to the process of moving from one state to another which is used to describe random forced outages rather than using the probabilities for the occurrence of these random events. The state transition rates provide the frequency and duration of outages as opposed to using the probability of these events to define the occurrences for modeling purposes.

The GE MARS model of Illinois, as well as the areas outside of Illinois that are part of PJM, and MISO was developed and simulated. The GE MARS model consists of Pools and Areas, where Areas are assigned to different Pools. In this model, the Pools are PJM, MISON (MISO North), and MISOS (MISO South). The assignment of each Area to Pool can be found in Appendix A of the full report. The Areas in Illinois are treated separately and apart from MISO and PJM, in the evaluation and calculation of ELCC and LOLE improvement to Illinois.

[618] ELCC is a measurement of a resource's ability to produce electric energy when the grid is most likely to experience supply shortfalls, that is the resource's ability to prevent an outage due to a supply shortfall. ELCC is typically represented as a percentage of a resource's capacity.

[619] LOLE is the expected number of days where load cannot be met with available resources. The LOLE determines the numbers of days in which a loss of load (i.e., a power outage/disconnection) would be expected to occur on average across a large number of system conditions. LOLE of 0.1 days/year is a de-facto standard, or criteria, in industry for probabilistic reliability metrics, sometimes referred to as "1 day in 10 years".

[620] In a Monte Carlo simulation analysis uncertainty for modeling variables is addressed by re-running the simulation many times selecting values for uncertain variables through a random draw from a probability distribution of values for that variable.

Specifically, this means that Illinois is modeled in isolation from the rest of PJM and MISO, and no market-specific externality (such as the ability to participate within one of the ISO's power or capacity marketplaces) is considered.[621]

The following items are included in the PJM and MISO database:

- Pools and Areas
- Load forecast and load forecast uncertainty
- Generating units (thermal, hourly modifiers, and energy limited resources)
- Hourly load, wind, and solar profiles
- Interface transmission limits between areas
- Emergency operating procedures

The policies are modelled in GE MARS as follows:

- HVDC Line: 2,650 MW of wind in Iowa modeled with hourly profiles from NREL's WIND TOOLKIT for the historical years 2007-2013,622 1,850 MW of solar in Iowa modeled with hourly profiles from NREL's NSRDB for the historical years 2007-2013, 650 MW of 4-hour energy storage.623 A transfer limit from Iowa to Illinois of 2,100 MW applied.
- Offshore wind in Lake Michigan: 200 MW offshore wind in Lake Michigan modeled with hourly profiles from NREL's WIND TOOLKIT for the historical years 2007-2013.
- ESS: 7,460 MW of ESS modeled with GE MARS energy storage model with 4 hours of storage duration and 85% round trip efficiency, and 40 MW of 10-hour energy storage. By 2030, 1,460 MW of 4-hour energy storage and the 40 MW of 10-hour storage are available.

To calculate the improvement to reliability that each policy has on the system, the initial system is brought to criteria (criteria is defined as a LOLE of 0.1 days/year and is the starting point for the analysis) by adding or removing perfect capacity. Perfect capacity is capacity that is always available (no forced or planned outages). From the system at criteria, the policy of interest is added to the database and the new LOLE is calculated. This calculation is done for each policy where Illinois is isolated from the rest of PJM and MISO, and when all of PJM and MISO are interconnected. This allows a calculation of the reliability impact that the policy has on Illinois' resource adequacy, as well as how they impact the surrounding regions.

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[621] Under present capacity market rules in PJM, HVDC transmission such as SOO Green are not able to qualify as capacity resources and thus would not be economically compensated for any capacity contributions made within PJM. However, capacity market compensation (or lack thereof) for a given modeled policy resource does not impact the goals of this specific study scope, which centers specifically around the added system reliability benefits of the various policy scenarios, such as the transmission resource in question, as modeled.

[622] NREL's Wind Integration National Dataset (WIND) Toolkit, which is the source for the 2013 - 2017 vintage data used for the Policy Study modeling is currently the publicly available data source that best meets the needs of power system modeling. An update and upgrade for the WIND Toolkit, the Wind Toolkit Long-Term Ensemble Dataset (WTK-LED), is currently being assembled and validated but is not yet ready for release. A report on the WTK-LED can be found at https://www.esig/weather-data-for-power-system-planning.

[623] The generation mix was provided to the IPA by SOO Green as part of an optimization study they conducted.

It should be noted that this exercise was designed to generate results that shed light on the reliability value of the various policies being examined. Bearing that in mind, the study is not intended to predict the real reliability of Illinois' electrical system in 2030 or 2040.[624] In this regard the study is starting from the initial perspective that the existing system is "meeting" its reliability standard at 0.1 LOLE (days/year), and thus the intent of assessing the various policy scenarios was not to evaluate whether the existing system construction (e.g., status quo) on its own is reliable, but more so to evaluate and measure the impact that the various policy scenarios would have on "improving reliability," e.g., demonstrating the net LOLE improvement from a starting point of 0.1 LOLE (days/year) of enacting different policies or combinations of policy scenarios.

To calculate the capacity value of each policy, the ELCC is calculated using GE MARS. The ELCC of a resource is the additional load that can be served while maintaining the same reliability level (LOLE of 0.1 days/year). This calculation allows a determination of how much capacity each policy contributes to improving the systems' reliability. The method for each policy is as follows:

1) Start with the initial system at criteria.
2) Add the resource being studied and record the region's LOLE.
3) Iteratively remove perfect capacity from the region until the LOLE returns to the initial LOLE value.

The resulting perfect capacity removed in step 3 is the ELCC of the resource.[625] Each resource added to the electric system helps increase the load that can be reliably supplied. The ELCC measures the resource's ability to produce electricity when the grid is most likely to experience an electricity shortage and is expressed as a percentage of a resource's total capacity. As an example, if the 200 MW offshore wind project in Lake Michigan has an ELCC of 29%, then the resource is assumed to be able to provide 58 MW towards meeting the shortage.

ii) Results and Impacts of the Policies

The results of the study show that all three proposals show a reduction in LOLE, and therefore an improvement in reliability. The reduction in LOLE is directly linked to the policy proposal's total capacity. The bigger capacity policies such as the HVDC Line and the ESS show the bigger improvement to Illinois' LOLE, whereas the smaller 200 MW offshore wind policy improves reliability less. For both study years 2030 and 2040, the combination of the three policies eliminates almost all LOLE in the system.

Table 8-11 and Figure 8-1 below show the detailed LOLE results of each policy case.

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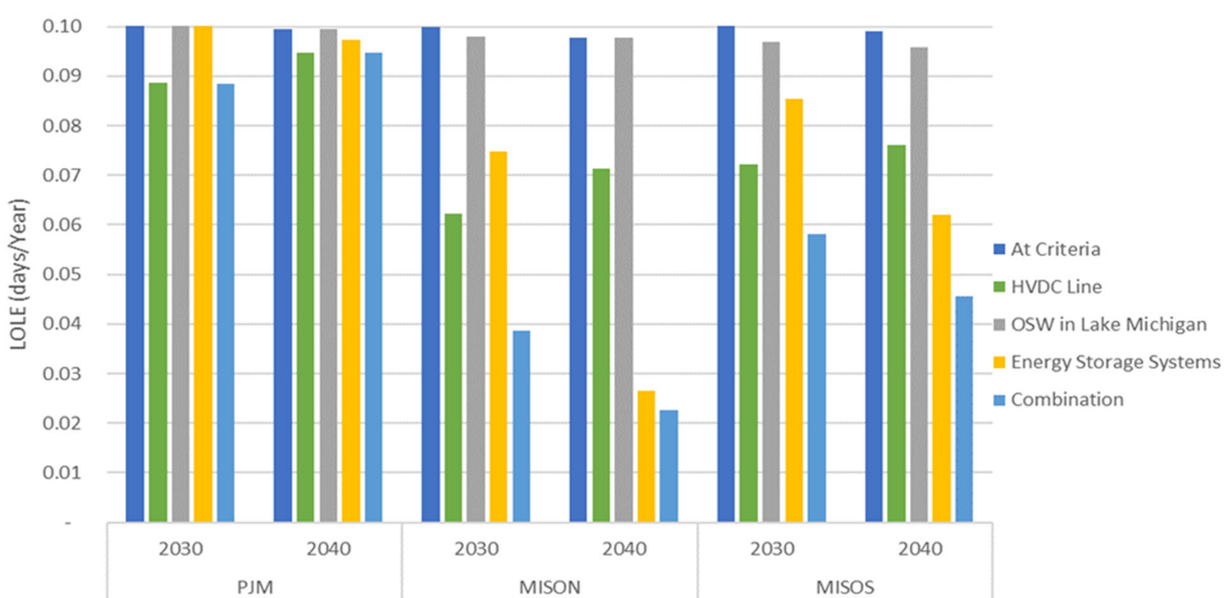
[624] Additionally, it should also be noted that this study accounted for state policies, such as the Climate and Equitable Jobs Act, that limits generator emissions and promotes renewable generation in the future.

[625] http://www.nrel.gov/docs/fy15osti/63038.pdf

Table 8-1: LOLE of Illinois for Each Policy

	LOLE (days/year)		Decrease in LOLE	
Case	**2030**	**2040**	**2030**	**2040**
At Criteria	0.10	0.10		
HVDC Line	0.00	0.01	0.10	0.09
Offshore Wind in Lake Michigan	0.09	0.09	0.01	0.01
Energy Storage Systems	0.01	0	0.09	0.10
Combination	0.00	0	0.10	0.10

Figure 8-1: LOLE of PJM, MISON, and MISOS for Each Policy in Illinois

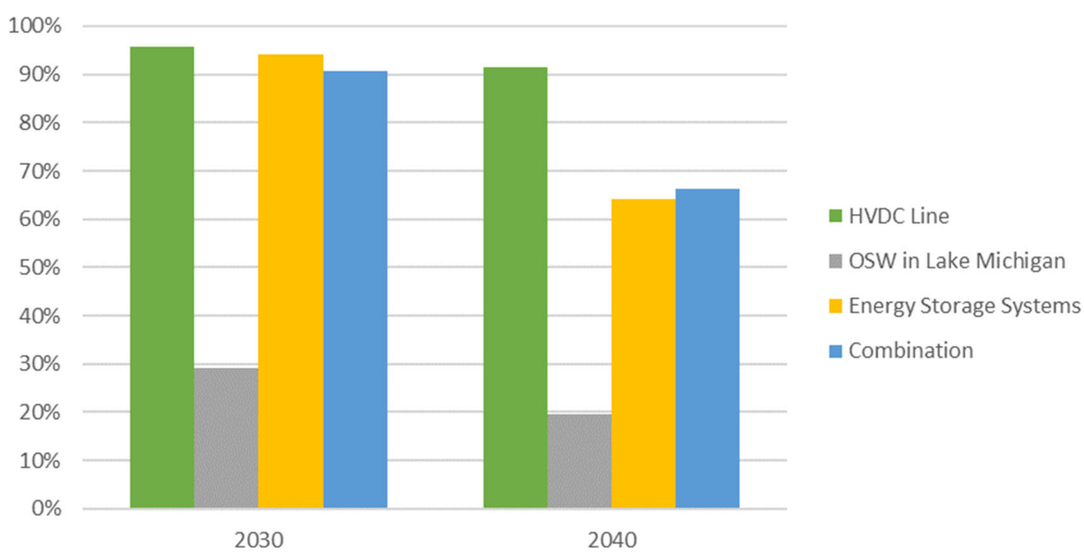


The study also shows that all three proposals also provide firm capacity contribution. Through the two study years, the ELCC of the HVDC Line policy is the most stable, at 96% and 92% of its nameplate capacity. The ELCC of the offshore wind in Lake Michigan decreases through time, from 29% in 2030 to 20% in 2040. This is caused by the shifting in LOLE in Illinois as the load and resource mix shifts. The ESS' ELCC decreases from 94% to 64% from 2030 to 2040. Although its ELCC % decreases through time, its ELCC capacity increases since the amount of ESS added by 2040 is higher than 2030. Table 8-2 and Figure 8-2 below provide the detailed results. Please note that the ELCCs generated in the below results reflect those calculated for the purposes of this study and within the singular footprint of the state of Illinois. Any published capacity accreditation information at the ISO-level (either from PJM or MISO in this instance) reflects ELCC figures computed using aggregated system-wide metrics and data. In short, ELCC data published by the ISOs for ISO resources cannot be assumed to be equivalent to those computed at the state-level, as is done in this present analysis.

Table 8-2: ELCC of Each Policy

	Nameplate (MW)		ELCC (MW)		ELCC (%)	
Case	**2030**	**2040**	**2030**	**2040**	**2030**	**2040**
HVDC Line	2,100	2,100	2,012	1,923	96%	92%
Offshore Wind in Lake Michigan	200	200	58	39	29%	20%
Energy Storage Systems	1,500	7,500	1,414	4,802	94%	64%
Combination	3,800	9,800	3,447	6,487	91%	66%

Figure 8-2: ELCC (%) of Each Policy



iii) Conclusion

The results of the study show that each policy proposal provides reliability benefits to the state of Illinois, which has a positive impact on resource adequacy. The improvement in reliability is directly linked to the policy proposal's total capacity. The bigger capacity of proposals of the HVDC Line and the ESS proposal provide bigger improvement to Illinois' reliability, whereas the smaller 200 MW offshore wind policy improves reliability less.

c) Analysis of the Impact on the Illinois Transmission System

i) Introduction

Among the potential impacts of these proposals that the IPA was directed to evaluate is the impact of the proposals on grid reliability in Illinois, which is the ability of the electric system to adequately supply the load connected to the system as the policy proposal resources are connected to the system. The evaluation of the impacts on grid reliability required that a technical analysis be conducted using power flow modeling of interconnecting the proposals into the Illinois transmission system in MISO and PJM. ENTRUST Solutions Group ("EN") was retained by Levitan & Associates, Inc ("LAI"), the IPA's Planning Consultant, to perform the impact analysis to determine the potential network upgrades[626] that would be required to interconnect the policy proposals and the associated costs of those network upgrades.

EN's full report is provided as Appendix E.

ii) Modeling Approach

The impact analysis involves conducting a power flow study using a power flow model. A power flow model simulates the flow of electrical power in a transmission system under certain conditions that could adversely affect the operation of the system. These conditions include the loss of certain electrical components of the transmission system such as downed transmission lines, equipment failures or generating plant outages. These losses of the electrical components are referred to as contingencies. The goal of the power flow analysis is to determine whether the flow of electrical power, under the different contingencies, will result in the flow on certain transmission system components, like transmission lines, exceeding the capability of the components (also called overloading of the components). The question to be answered is whether or not this overloading of the system components would cause a violation of the flow of power since the power is expected to flow within the required limits of the capabilities of the transmission system components.[627] Contingencies and violations are therefore key concepts in determining whether a particular injection of power into the transmission system through a new interconnection will result in the need for certain transmission system components to be upgraded (network upgrades) because the flow of power results in violations to their limits.

The power flow analysis identifies the potential electric system operating contingencies that could be caused by the interconnection of the resources that would be associated with the policy proposals. The power flow modeling identifies and evaluates the contingency

[626] Network upgrades, also referred to as transmission system upgrades, are transmission system modifications to accommodate the interconnection of new or existing generation resources in order to ensure the reliability of the transmission system.

[627] For example, if a transmission line is taken offline for maintenance, or is offline due to an outage, can the remaining lines in the system handle the required system loads without their rated values.

conditions and provides estimated for the costs of transmission system improvements (network upgrades) that would be necessary to mitigate the contingency conditions. The costs of the network upgrades are determined by the size of the impact that a resource seeking interconnection has on the system. The larger the impact the higher the network upgrade costs.

The impact analysis was conducted using power flow modeling software which identifies and quantifies the metrics that can be used to assess whether the transmission system will continue to operate reliably after the addition of the new electric resources that would be encouraged by the policy proposals. For each of the policy proposals the magnitude of the upgrade costs provides a guide to the impact that the proposals will have on the electric grid in Illinois. The network upgrades mitigate the negative impacts on the grid that are associated with interconnecting generation, storage and transmission resources.

The power flow analysis can also provide some indication of whether or not the new resources, once they are interconnected, can have a positive impact on grid resilience. Resilience is the ability of the grid to respond to and recover from disruptions such as equipment failures or events that down transmission lines or force generating or storage resources offline. However, this is an indirect measure which only shows whether the connected resources can help the system respond to these disruptions. Resources once connected can have either no impact or in some cases a positive impact on grid resilience.

Power flow models are used extensively in the power industry to analyze the impacts on existing power systems and to identify contingencies that could be associated with new resources being added to the transmission grid. RTOs and ISOs use power flow models as the starting point for system interconnection studies. The key outputs from the power flow modeling are the results of the thermal analysis which identifies any violations based on the applied contingencies and sets the basis for determining the network upgrade requirements and the estimated costs for these upgrades. For PJM, the study models used in the EN impact analysis include the Siemens PTI PSS®E power flow software (Version 34), and the PowerGEM TARA software version 2302a which was used for the PJM Generator Deliverability analysis[628], specifically using the PJM Generator Deliverability 2022 Reform Tool ("GD Tool"). The MISO analysis was conducted in PowerGEM TARA software version 2301.

iii) Overview of the Generation Interconnection Process

The generation interconnection process studies the impact of the addition of capacity and energy sources into the transmission system. New interconnection requests are studied according to the process defined by the respective RTO that oversees the requested point of interconnection. These studies identify any constraints caused by the new interconnecting project to the transmission system. The RTO determines mitigation and the network

[628] A deliverability analysis is part of the power flow study and includes a specific determination of the deliverability of capacity within the power system.

upgrades required to be in place before the interconnection request can go into service. New interconnection requests are allocated costs for these upgrades based on their impact on the transmission system. A successful interconnection application will result in the execution of an interconnection agreement that allows a connection to the transmission system. PJM and MISO are two different RTOs that are located in the state of Illinois.

Both PJM and MISO have interconnection processes which typically include three studies: the feasibility study, the system impact and the facilities study --- each study's scope increasing an more detailed. After completion of each study, the interconnection customer makes the determination to advance their project to the next phase based on the information and costs provided or withdraw the project from the queue. Once the decisions have been made, a restudy may be performed as it could change the impact and the network upgrades required for other queued generators. Assigned network upgrades and facility costs are subject to change at any time until the project executes an interconnection agreement.

Throughout the interconnection process, several factors can cause the expected network upgrades and associated costs for a project to fluctuate, sometimes significantly. Earlier queued projects could withdraw their interconnection request, existing generators may announce plans to retire, or baseline system transmission needs could be developed through the RTO's Regional Transmission Expansion Plan. For example, in PJM, in addition to the system changes, as a request passes through each phase of the study process, the PJM and Transmission Owners may develop and refine the scopes of the network upgrades to get a clearer picture of what a network upgrade will cost. Depending on the size and impact of a project, the scope of the network upgrades and costs can vary widely. For example, in PJM, the total cost of network upgrades identified in the Feasibility Study of queue position AF1-200[629] was $715,116,062.[630] In the following study phase --- the System Impact Study --- the total cost of identified network upgrades were $232,966,340, of which AF1-200 bore the cost responsibility for $163,399,789.[631] These costs were developed in the former PJM interconnection process. PJM has since transitioned to a new interconnection process where AF1-200 will be re-studied, and the network upgrade costs updated. There are many moving pieces on the transmission system that could alter the results and anticipated costs of the interconnection process as it is taking place, and the total network upgrade costs will not be final and locked in until a project signs an interconnection agreement. The uncertainty associated with the cost of network upgrades therefore presents considerable challenges for interconnection customers and will also provide considerable challenges for the policy proposals when they submit their interconnection requests in PJM and MISO.

It is important to note that, while the methodologies used for the impact analyses of the proposals contained in this report are consistent with the methodologies used in MISO and PJM, the impact analyses do not constitute full blown interconnection studies but high-level

[629] AF1-200 is the queue position of the SOO Green project in the previous PJM interconnection process.

[630] AF1-200 (pjm.com)

[631] af1200_imp.pdf (pjm.com)

feasibility studies. The costs for network upgrades contained in this report should therefore not be considered to be the final costs associated with an interconnection agreement or even comparable to the costs in a system impact study as those costs are from higher level studies and more refined. The costs provided in this report are meant to provide a preliminary guide for the costs associated with the transmission grid impacts of the policy proposals. These costs will most certainly change as the policy proposals move forward in the interconnection process through to a formal interconnection request in PJM or MISO and to the completion of the interconnection process.

iv) Input Data Assumptions

The generation interconnection process studies the impact of the addition of capacity and energy sources into the transmission system. New interconnection requests are studied according to the process defined by the respective RTO that oversees the requested point of interconnection. These studies identify any constraints caused by the new interconnecting project to the transmission system. The RTO determines mitigation and the network upgrades required to be in place before the interconnection request can go into service. New interconnection requests are allocated costs for these upgrades based on their impact on the transmission system. A successful interconnection application will result in the execution of an interconnection agreement that allows a connection to the transmission system. PJM and MISO are two different RTOs that are located in the state of Illinois.

Both PJM and MISO have interconnection processes which typically include three studies: the feasibility study, the system impact study and the facilities study --- each study's scope increasing and more detailed. After completion of each study, the interconnection customer makes the determination to advance their project to the next phase based on the information and costs provided or withdraw the project from the queue. Once the decisions have been made, a restudy may be performed as it could change the impact and the network upgrades required for other queued generators. Assigned network upgrades and facility costs are subject to change at any time until the project executes an interconnection agreement.

Throughout the interconnection process, several factors can cause the expected network upgrades and associated costs for a project to fluctuate, sometimes significantly. Earlier queued projects could withdraw their interconnection request, existing generators may announce plans to retire, or baseline system transmission needs could be developed through the RTO's Regional Transmission Expansion Plan. For example, in PJM, in addition to the system changes, as a request passes through each phase of the study process, the PJM and Transmission Owners may develop and refine the scopes of the network upgrades to get a clearer picture of what a network upgrade will cost. Depending on the size and impact of a project, the scope of the network upgrades and costs can vary widely. For example, in PJM, the total cost of network upgrades identified in the Feasibility Study of queue position AF1-

200[632] was $715,116,062.[633] In the following study phase --- the System Impact Study --- the total cost of identified network upgrades were $232,966,340, of which AF1-200 bore the cost responsibility for $163,399,789.[634] These costs were developed in the former PJM interconnection process. PJM has since transitioned to a new interconnection process where AF1-200 will be re-studied, and the network upgrade costs updated. There are many moving pieces on the transmission system that could alter the results and anticipated costs of the interconnection process as it is taking place, and the total network upgrade costs will not be final and locked in until a project signs an interconnection agreement. The uncertainty associated with the cost of network upgrades therefore presents considerable challenges for interconnection customers and will also provide considerable challenges for the policy proposals when they submit their interconnection requests in PJM and MISO.

It is important to note that, while the methodologies used for the impact analyses of the proposals contained in this report are consistent with the methodologies used in MISO and PJM, the impact analyses do not constitute full blown interconnection studies but high-level feasibility studies. The costs for network upgrades contained in this report should therefore not be considered to be the final costs associated with an interconnection agreement or even comparable to the costs in a system impact study as those costs are from higher level studies and more refined. The costs provided in this report are meant to provide a preliminary guide for the costs associated with the transmission grid impacts of the policy proposals. These costs will most certainly change as the policy proposals move forward in the interconnection process through a formal interconnection request in PJM or MISO and complete the interconnection process.

v) Input Data Assumptions

Key input data on the proposals was received from LAI, courtesy of the IPA. The IPA reached out to different stakeholders for assistance in determining the modeling assumptions for the respective proposals, including the capacities of the respective projects and the proposed points of interconnection.

- Information on the points of interconnection for the offshore wind project was obtained from a prospective developer of the project.
- The Clean Grid Alliance, the American Clean Power Association, the Solar Energy Industries Association, and the Coalition for Community Solar Access ("the Associations") recommended that the IPA use ESS projects in the PJM and MISO queues (including their capacities and points of interconnection), as indicative projects that would be built to meet the ESS targets in the policy proposal.

[632] AF1-200 is the queue position of the SOO Green project in the previous PJM interconnection process.

[633] https://www.pjm.com/pub/planning/project-queues/merch-feas_docs/af1200_fea.pdf

[634] https://www.pjm.com/pub/planning/project-queues/merch-impact-studies/af1200_imp.pdf

- The developers of the SOO Green HVDC Transmission Line provided the information on the capacity and points of interconnection for the project.

vi) Results and Impact of the Policies

Impact analyses were performed for each of the policy proposals, and the results of the analyses show that all three of the proposals will require network upgrades to the transmission system in order to be able to interconnect into PJM or MISO, and to provide grid reliability benefits for Illinois ratepayers. The resources seeking interconnections involving the proposals will be responsible for the costs of the respective network upgrades. The requirement for network upgrades is typical for most interconnections as some level of transmission investment is almost always needed to maintain transmission system reliability with new interconnections. More detailed results are provided below.

vii) Analysis of the Lake Michigan Offshore Wind Proposal

This study identified the potential network upgrades and associated costs for five different points of interconnection in the PJM area for the 200 MW[635] offshore wind project. The study results concluded that the primary point of interconnection, Stateline 138 kV, was the most suitable of the five points of interconnection in terms of transmission system impacts and network upgrade costs. The analysis also shows that this proposal does not have an impact, either positive, or negative, on grid resilience. The network upgrade costs show the magnitude of the impacts that the offshore wind project would have on the Illinois grid depending on the interconnection point. When the upgrade costs are considered on a $/MW basis, the Stateline 138 kV point is the most favorable compared with the other four points analyzed. The results of the power flow analysis demonstrate the high cost of implementing the offshore wind proposal as compared with the other policy proposals, primarily reflecting the relatively small scale of the project.

Table 8-3 below provides a listing of the network upgrades for each interconnection point.

Table 8-3: Network Upgrade Costs for Each Point of Interconnection

Point of Interconnection	Cost of Network Upgrades ($MM)	Cost of Network Upgrades $/MW
Stateline 138 kV	331.2	$1,656,000
Calumet 138 kV	369.6	$1,848,000
North Harbor 138 kV	369.6	$1,848,000
Stateline 345 kV	450.5	$2,252,500
Calumet 345 kV	390.9	$1,954,500

[635] The 200 MW capacity was determined based on information in the policy proposal.

Based on the current status of PJM Transition Cycle #1, Transition Cycle #2, and Cycle #1 in PJM's interconnection review process it is not possible at this point to accurately determine the cost allocation of network upgrades for a project that will be studied as part of Cycle #1. For this reason, the modeling assumed that the project had 100% of the network upgrades cost allocated to it. Since this modeling is only a feasibility study it is too early to accurately determine the project's cost allocation as that allocation is normally conducted at the System Impact Study phase. As other projects enter and withdraw from the generation queue and network upgrades for those projects are developed, the cost responsibility for future projects will become clearer. Most network upgrades assigned to the offshore wind project will be allocated to other generation interconnection projects, resulting in a reduction of the costs allocated to the offshore wind project.

viii) Analysis of the Energy Storage Proposal

The power flow analysis considered 45 currently queued ESS interconnection location requests in MISO and PJM. Potential network upgrades were analyzed for 35 ESS queue locations in MISO and 10 locations in PJM. The costs of the network upgrades that would be required to interconnect the ESS projects are shown in Table 8-4 and Table 8-5 The costs of the network upgrades on a $/MW basis show the relative impacts on the Illinois grid of a storage facility constructed at each of the queue locations. Three ESS locations in MISO, J2170, J2552 and J2607 would have a positive impact on grid resilience. For the ESS locations in PJM, five ESS locations, AF2-441, AH2-204, AH2-259, AH2-290, and AH2-339 would have a positive impact on grid resilience.

Table 8-4: MISO ESS Network Upgrade Costs and Unit Costs

Queue Position	Queue Cycle	Project Size (MW)	Cost of Network Upgrades ($)	Cost of Network Upgrades ($/MW)
J1655	DPP-2020	50	$ 12,091,984.29	$ 241,839.69
J1695	DPP-2020	50	$ 5,975,035.02	$ 119,500.70
J1882	DPP-2021	45	$ 6,310,000.00	$ 140,222.22
J1973	DPP-2021	40	$ 1,777,500.00	$ 44,437.50
J1975	DPP-2021	40	$ 1,721,000.00	$ 43,025.00
J2124	DPP-2021	100	$ 4,016,900.00	$ 40,169.00
J2159	DPP-2021	50	$ 7,190,000.00	$143,800.00
J2161	DPP-2021	50	$ 922,857.85	$ 18,457.16

Queue Position	Queue Cycle	Project Size (MW)	Cost of Network Upgrades ($)	Cost of Network Upgrades ($/MW)
J2170	DPP-2021	150	$ 122,710,000.00	$ 818,066.67
J2195	DPP-2021	100	$ 8,337,700.00	$ 83,377.00
J2197	DPP-2021	100	$ 8,436,600.00	$ 84,366.00
J2375	DPP-2022	100	-	-
J2376	DPP-2022	60	$ 29,820,000.00	$ 497,000.00
J2377	DPP-2022	300	$ 6,970,000.00	$ 23,233.33
J2379	DPP-2022	200	$ 12,311,000.00	$ 61,555.00
J2383	DPP-2022	100	$ 2,350,000.00	$ 23,500.00
J2402	DPP-2022	200	$ 1,290,000.00	$ 6,450.00
J2413	DPP-2022	150	$ 13,091,560.00	$ 87,277.07
J2426	DPP-2022	200	$ 39,830,000.00	$ 199,150.00
J2532	DPP-2022	200	$ 18,790,000.00	$ 93,950.00
J2536	DPP-2022	200	$ 4,360,000.00	$ 21,800.00
J2551	DPP-2022	110	$ 13,270,000.00	$ 120,636.36
J2552	DPP-2022	80	$ 8,180,000.00	$ 102,250.00
J2575	DPP-2022	198	$ 23,350,000.00	$ 117,929.29
J2607	DPP-2022	200	$ 7,480,000.00	$ 37,400.00
J2627	DPP-2022	150	$ 14,880,000.00	$ 99,200.00
J2647	DPP-2022	300	$ 6,100,000.00	$ 20,333.33
J2724	DPP-2022	300	$ 11,290,000.00	$ 37,633.33
J2853	DPP-2022	100	$ 6,570,300.00	$ 65,703.00
J2974	DPP-2022	50	$ 29,256,500.00	$ 585,130.00
J2998	DPP-2022	200	$ 34,449,313.92	$ 172,246.57
J3011	DPP-2022	100	$ 17,587,400.00	$ 175,874.00

Queue Position	Queue Cycle	Project Size (MW)	Cost of Network Upgrades ($)	Cost of Network Upgrades ($/MW)
J3031	DPP-2022	200	$ 13,210,000.00	$ 66,050.00
J3200	DPP-2022	250	$ 18,782,500.00	$ 75,130.00
J3216	DPP-2022	300	$ 6,970,000.00	$ 23,233.33

Table 8-5: PJM ESS Cost of Network Upgrades and Unit Costs

Queue Position	Project Size (MW)	Cost of Network Upgrades ($MM)	Cost of Network Upgrades ($/MW)
AG1-298	500	67.47	134,940
AG2-357	250	13.77	55,080
AG2-545	400	19.65	49,125
AF2-441	250	50.08	200,320
AH2-015	110	157.52	1,432,000
AH2-204	170	113.24	666,118
AH2-259	150	119.25	795,000
AH2-290	60	19.29	321,500
AH2-339	110	425.05	3,864,091
AH2-341	250	220.11	880,440

Based on the current status of PJM's Transition Cycle #1, Transition Cycle #2, and Cycle #1 it is not possible at this point to accurately determine the cost allocation of network upgrades for a project that will be studied as part of Cycle #1. As other projects enter and withdraw from the generation queue and network upgrades for those projects are developed, the cost responsibility for future projects will become clearer.

ix) Analysis of the SOO Green HVDC Transmission Link Proposal

This analysis determined the estimated costs for the potential network upgrades for interconnecting the SOO Green HVDC line into PJM. The results in Table 8-6, show the costs of network upgrades that would be required to interconnect this proposal. This proposal also shows a positive impact on grid resilience.

Table 8-6 Cost of SOO Green Network Upgrades and Unit Cost

Project Size (MW)	Cost of Network Upgrades ($MM)	Cost of Network Upgrades ($/MW)
2,035	801.8	394,005

SOO Green is part of the Transition Cycle #1 and cycles such as Transition Cycle #1, Transition Cycle #2, and Cycle #1 are still a work in progress because of PJM's reform process, any updated cost for the network upgrades for SOO Green will only be known after the completion of the respective cycle. As the cycles go through decision points and projects either withdraw or enter the queue, the cost of the SOO Green project will become more certain.

x) Conclusion

The results of the analysis show that all the proposals will require some level of network upgrades in order for them to be able to reliably interconnect to the Illinois transmission system in PJM and MISO. The impacts of the proposals can be compared using the network upgrade costs on $/MW basis for the results presented in Table 8-4 through 8-6. For comparative purposes, most of the MISO ESS queue locations (30 of the 35 locations analyzed) and three of the ESS queue locations in PJM have relatively low impacts on the Illinois grid. In terms of the relative impacts, the SOO Green project is next after the ESS locations and, with the exception of PJM ESS queue location AH2-339, the offshore wind proposal has the largest impact on the grid on a $/MW basis which is primarily due to the small size of the project and its relatively high costs as shown by the production simulation modeling discussed elsewhere in this report.

The costs for the network upgrades are generally the responsibility of the projects making the interconnection requests and moving through the interconnection and development process to construction. The network upgrade costs reflect the additional costs for bringing the generation, transmission and storage resources covered by the policy proposals online. These costs will be recovered through market revenues and subsidies such as RECs or Energy Storage Credits and will ultimately be passed on to ratepayers in Illinois. The network upgrade costs, which are preliminary, provide a guide in determining whether to move forward with policies that will encourage these proposals.

d) Impact on Electricity Prices and Emissions

As part of the IPA's evaluation of the impacts of the Policy Study proposals, Public Act 103-0580 directs the Agency to evaluate the wholesale electricity price impacts, the net rate impacts on Illinois ratepayers, the impacts on the carbon and other pollutant emissions, and the impacts of the state's decarbonization goals. The Agency utilized production simulation modeling to assess these impacts. Production simulation models are widely used in the power industry to estimate the cost of electricity and to simulate the operation of generation and transmission systems under a specified set of assumptions about electricity demand, fuel prices, and generation resource mix and operating performance. In the present context production simulation modeling can answer questions regarding the Policy proposals' impacts on wholesale electricity prices, emissions, and changes to the composition and operation of the generation resource mix in Illinois over the modeling time horizon.

i) Production Simulation Modeling

Production simulation models require an extensive database that can provide information on resource technologies, including nuclear, coal, natural gas, wind or solar resources, the capital and operating costs for each generating facility, operational limitations, fuel prices, and emissions, among other characteristics that together provide a complete picture of how each generating resource in the region that is being modeled will operate. The models typically use an algorithm that draws on the database to simulate the operation of the system in a least cost manner, that is the lowest cost resources are operated first up to the total amount of resources required to generate the electricity that is needed to meet the electric system load. The simulated least-cost operation is subject to various constraints such as transmission limits and plant operating characteristics.

Aurora, a chronological dispatch simulation model licensed from Energy Exemplar, was utilized for the Policy Study impact evaluations to forecast power market outcomes, including energy prices, capacity prices, power plant emissions, and natural gas demand for electric generation. The default database provided by Energy Exemplar was used as a foundation for the modeling inputs. Energy Exemplar's database is augmented with extensive customization based on public data sources and modeling experience. Aurora was used to model the impact of three policy proposals:

1. Offshore wind project in Lake Michigan;
2. The SOO Green HVDC transmission line and associated renewable energy to energize it; and
3. Energy Storage Systems

Each of the individual policy proposals were included in a "but for" test that compared power market outcomes against a Base Case without the policy proposal resources against a modeling run with these resources in place. A comparison of the simulation results with the base case provides a picture of how these additions would change the way the electric system operates, the mix of generation resources and the cost of generating electricity. A combined case with all three policy proposals enacted was also modeled. The Aurora modeling was run with 2025 through 2050 as the study period.

For the final Policy Study the Agency made several revisions to the Aurora modeling and the resulting impacts on energy costs impacts and emissions reported in the study.

First, as described in the Agency's February 8, 2024 errata announcement, the Agency identified an error in how some modeling results were reported in the draft Policy Study that understated the potential benefits associated with the energy storage policy option.

Second, as also described in the errata announcement, errors were found in the presentation of costs for SOO Green and in the combined case model that looked at adopting all three of the policies studied. The primary error occurred when the energy revenue outputs for the energy storage modeling and the offshore wind component of the combined results were transferred into summary spreadsheets for use in the preparation of the draft Policy Study. More specifically, certain data outputs of Aurora (the production cost simulation model used for the Policy Study to model impacts on wholesale electricity prices, emissions, and changes to the composition and operation of the generation resource mix in Illinois) are reported in thousands of dollars, and those were not consistently updated during the transfer to the summary spreadsheets. Additional errors include: (1) the use of an incorrect financing carrying cost that did not reflect the benefits of the Investment Tax Credit, affecting the cost calculations for distributed energy storage; (2) the use of inflation adjusted costs rather than nominal costs in certain tables, affecting the cost calculations for SOO Green; and (3) the cost calculation erroneously double-counted certain project revenues for SOO Green, affecting the combined case results. The errors did not impact the reporting of results of the modeling for offshore wind as a stand-alone case.

Third, after the release of the errata announcement, and in part through review of stakeholder comments on the draft Policy Study, errata, and workpapers, the Agency identified and made additional corrections that included correcting an error that inadvertently excluded the Investment Tax Credit from being applied to the proposed offshore wind project which lowered its estimated costs, corrected the retirement date for certain gas and nuclear units which impacted electric price and emissions modeling, and updated the capacity price used for the ComEd zone to reflect a recent FERC order that establishes a new CONE for the ComEd zone.

These revisions cascade through the entire Aurora model, changing project costs, energy and capacity revenues, energy market revenues, total costs, and emissions outputs. The overall impact of each set of the revisions made between the draft and final versions of this Policy Study is that the estimated support needed for each policy has declined compared to the draft Policy Study. While CO_2 emissions changed slightly, SO_2, NO_X and $PM_{2.5}$ emissions reductions all declined compared to the draft Policy Study, primarily due to the updating of plant retirements, and in the case of offshore wind the change in SO_2 and NO_x emissions settled at being a small net increase in emissions compared to the base case.

Assumptions in the Base Case represent "known and knowable" expectations for Illinois and other states' energy policies. The modeling included the specific state policy measures and goals that have been announced, such as procurement targets for large-scale clean energy technologies and settled state procurements. The modeling inputs for MISO relied primarily on Series 1A MISO Futures modeling conducted by the Regional Transmission Organization ("RTO") for long-term planning purposes, specifically Future 1A. The Futures refresh modeling includes three Future scenarios, referred to as 1A, 2A, and 3A, that incorporate a range of load and resource assumptions. Future 1A includes the most conservative modeling approach to decarbonization but incorporates the latest generation changes contemplated in utility Integrated Resource Plans ("IRPs").[636] ").[637]

In comments on the draft Policy Study, the Illinois Clean Jobs Coalition ("ICJC") recommended the use of Future 2A as the core scenario of the Policy Study.[638] Future 2A represents a more aggressive decarbonization path compared to Future 1A and is the middle option in the Futures Scenarios. The aggressive resource expansion found in Future 2A assumes significant leaps in MISO's resource mix occur before the projects supported by the policy proposals studied through this Policy Study are even in service. For example, MISO Future 2A includes 23 GW of "flex" resources in MISO North/Central (3 GW in Illinois) *by 2027*, despite the flex resource representing no specific technology in particular.[639] Several commentors on the draft Policy Study expressed concern regarding the use of this sort of proxy unit in the Policy Study modeling; having a wide proliferation of flex resources across the study region before those new projects have been placed into service is unrealistic, rendering any modeling across the 2030-2049 period unreliable. In the IPA's view, Future 1 resource additions can be expected with greater certainty and more often reflect queued and planned projects grounded in progress from developers and utility planning (for example, only 14 GW of "model-built" resources are built in Future 1A, as opposed to 169 GW in Future 2).[640] The large influx of near-term model-built resources in Future 2A may be unrealistic, with 64 GW built by 2030.[641]

The working Base Case for PJM was developed from publicly available documentation.

[636] See F1 for a description of assumptions in MISO's Series 1 modeling for Future 1: https://cdn.misoenergy.org/MISO Futures One Pager538214.pdf

[637] See F1 for a description of assumptions in MISO's Series 1 modeling for Future 1: https://cdn.misoenergy.org/MISO Futures One Pager538214.pdf

[638] ICJC comments, pp.5-6. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240213-icjc-power-sector-committee.pdf

[639] "These 'Flex' units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: reciprocating internal combustion engines (RICE units), long-duration battery (>4 hours), traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear SMRs, green hydrogen, enhanced geothermal systems, and other emerging technologies." MISO Futures Report, Series 1A, published November 1, 2023. See pages 2-3. https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

[640] Model-built resources are selected by MISO's capacity expansion model, unlike planned resources that are expected to be built per a survey of MISO members.

[641] *Id*, pages 54-55.

In this study, all dollar values, unless otherwise noted, are conveyed in nominal dollars. In some instances, real dollars, or constant dollars, are used.[642] Real dollars are adjusted for their purchasing power in a given year, usually (and in this analysis) controlling per inflation. The long-term inflation assumption used in this analysis was 2.5% for converting constant dollar values to nominal values, consistent with the NREL Annual Technology Baseline ("ATB"). Given the long time horizon for this study, the compounding effect of inflation means that a nominal dollar in the beginning of the study period is likely to be worth much more in real dollar terms than a nominal dollar at the end of the study period.

ii) Modeling Assumptions and Inputs

Following is a summary of the modeling assumptions and inputs used in the Aurora modeling. More detailed discussion of the inputs and assumptions can be found in the full simulation modeling report in Appendix E.

(1) Transmission

Inter-zonal transmission transfer limits are defined using several publicly available data sources:

- MISO Loss of Load Expectation ("LOLE") Working Group Materials (Seasonal Capacity Import Limits and Capacity Export Limits)[643]
- PJM Base Residual Auction ("BRA") Planning Parameters[644]

These sources represent emergency transfer limits that may be used during particularly tight system conditions. In PJM, these limits are adjusted to reflect operating data provided as PJM Day Ahead Interface Flows and Limits.

(2) Demand Forecast

RTO planning documents were relied upon as the basis for peak and annual energy forecasts. MISO has published hourly and summary level load data for the Series 1A MISO Futures in meeting materials for the Long-Range Transmission Planning ("LRTP") Workshop.[645] The Series 1A Futures forecast load through 2042. Future 1 forecasted load was extrapolated through 2050 assuming exponential growth consistent with the Combined Annual Growth Rate ("CAGR") over the forecast. The 2042 hourly load shape is applied to the remaining years in the forecast.

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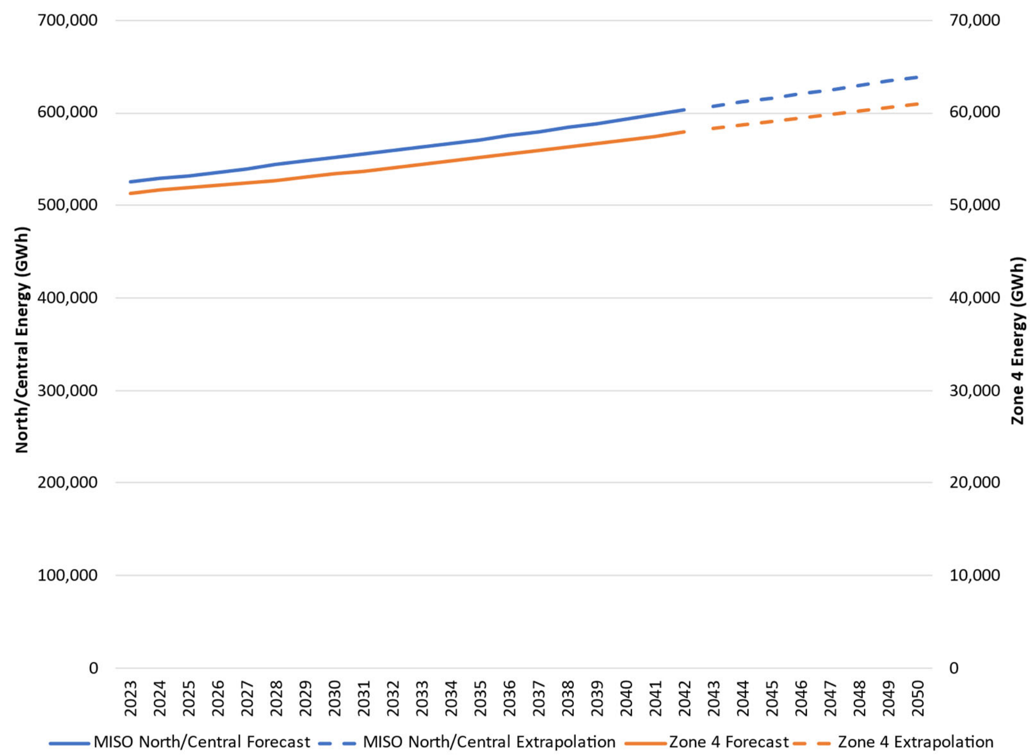
[642] United States Census Bureau, Current versus Constant (or Real) Dollars, accessed February 27, 2024. Current versus Constant (or Real) Dollars (census.gov)

[643] The latest import and export limits are posted here: https://cdn.misoenergy.org/20231017%20LOLEWG%20Item%2004%20PY%202024-25%20Final%20CIL-CEL%20Results630536.pdf

[644] PJM identifies Capacity Emergency Transfer Limits (CTEL) in BRA planning parameters, found here: PJM - Capacity Market (RPM)

[645] Long Range Transmission Planning (LRTP) Workshop (misoenergy.org) See April 28th meeting.

Figure 8-3: Annual Energy Forecast, MISO[646]



PJM's 2023 Load Forecast Report data includes monthly metered and peak load values by zone through 2035. The load forecast for the rest of the study period was extrapolated by reconstituting the net energy for load through adding back in behind the meter ("BTM") solar generation. Net energy for load was extrapolated forward assuming exponential growth consistent with the CAGR over the forecast.[647] PJM does not provide an hourly demand shape, so 2011 historical demand was the shaping factor input into Aurora.[648] The PJM 2011 shaping profile is drawn from PJM estimates of unrestricted load with solar addbacks, adjusted to account for some missing data and anomalies via a review of metered load.[649] The PJM 2011 shaping profile is drawn from PJM estimates of unrestricted load with solar addbacks, adjusted to account for some missing data and anomalies via a review of metered load.[650] BTM solar, which is separately defined in PJM planning documents, is defined as a supply-side resource in order to reflect the changes to the hourly shape of net load that solar

[646] Zone 4 is made up of three Local Balancing Authorities based in Illinois: Ameren Illinois (AMIL), City Water Light & Power (CWPLP), and Southern Illinois Power Cooperative (SIPC). See Table 56. https://www.purdue.edu/discoverypark/sufg/docs/publications/MISO/MISO forecast report 2022.pdf.

[647] Some CAGR sampling adjustments are made to zones to account for transient changes in demand that individual utilities request (see load-forecast-supplement.ashx (pjm.com) pp 18-22 and other observed near-term growth that is inconsistent with long-term trends.

[648] 2011 is used as the historical year for shaping as data sources are available to generate renewable profiles for this weather year, and limited BTM solar was in service that could skew the shape applied to gross load. 2011 weather year data is also available in NREL's WIND Toolkit database which is the source for wind resource data.

[649] See https://www.pjm.com/planning/-/media/FA6652A369C14A3CA9F1FFAE57CA88A5.ashx for the primary source and Data Miner 2 (pjm.com) for metered load utilized as a backstop.

[650] See https://www.pjm.com/planning/-/media/FA6652A369C14A3CA9F1FFAE57CA88A5.ashx for the primary source, and https://dataminer2.pjm.com/feed/hrl_load_metered/definition for metered load utilized as a backstop.

creates, as solar generation does not track demand. BTM solar generation is assumed to grow at a constant MWh rate per the last year's forecasted growth rate. BTM solar growth outpaces gross load growth in the extrapolated years.

Modeling assumptions were finalized prior to the release of PJM's 2024 Load Forecast Report. The updated load forecast has significantly increased, by about 14.5% on a net energy basis.[651] The forecast for ComEd has increased by 12.6% over the same period. Notably ComEd's load increase is lower than the full PJM RTO.

Table 8-7: PJM Load Forecast Comparison

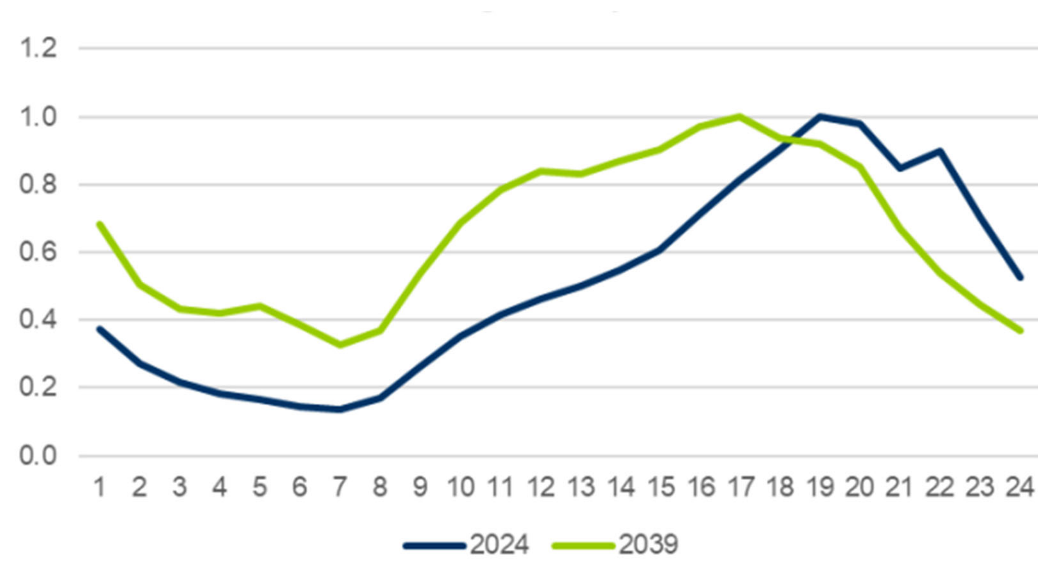
Energy (GWh)	**Market**	**2030**	**2038**	**Source**
2024 Forecast	ComEd	94,557	101,528	Table E-1 2024
2023 Forecast	ComEd	91,157	90,253	Table E-1 2023
% Change	ComEd	3.73%	12.49%	(2024 Load / 2023 Load) – 1
Energy (GWh)	**Market**	**2030**	**2038**	**Source**
2024 Forecast	PJM	952,578	1,099,538	Table E-1 2024
2023 Forecast	PJM	878,461	960,428	Table E-1 2023
% Change	PJM	8.44%	14.48%	(2024 Load / 2023 Load) – 1
Summer Peak (MW)	**Market**	2030	2038	**Source**
2024 Summer Forecast	ComEd	20,204	21,005	Table B-1 2024
2023 Summer Forecast	ComEd	19,888	19,481	Table B-1 2023
% Change	ComEd	1.59%	7.82%	(2024 Load / 2023 Load) - 1
Summer Peak (MW)	**Market**	2030	2038	**Source**
2024 Summer Forecast	PJM	167,873	187,752	Table B-1 2024
2023 Summer Forecast	PJM	157,899	167,567	Table B-1 2023
% Change	PJM	6.32%	12.05%	(2024 Load / 2023 Load) - 1
Winter Peak (MW)	**Market**	2030	2038	**Source**
2024 Winter Forecast	ComEd	15,196	16,267	Table B-2 2024
2023 Winter Forecast	ComEd	14,625	14,487	Table B-2 2023
% Change	ComEd	3.90%	12.29%	(2024 Load / 2023 Load) - 1
Winter Peak (MW)	**Market**	2030	2038	**Source**
2024 Winter Forecast	PJM	152,870	173,502	Table B-2 2024
2023 Winter Forecast	PJM	141,280	150,555	Table B-2 2023
% Change	PJM	8.20%	15.24%	(2024 Load / 2023 Load) - 1

Portions of the peak demand increase that PJM is positing may be mitigated by changes to EV charging behavior. PJM Load Forecast Subcommittee materials indicate that the impact of additional EVs to the forecast adds around 20 GW to the summer and winter peak

[651] The last shared year of the report is 2038; the most recent forecast for the RTO wide is 1,099,538 GWh, compared to 960,428 GWh in the previous report. The new report is here: https://www.pjm.com/-/media/library/reports-notices/load-forecast/2024-load-report.ashx.

forecasts by 2038.[652] While PJM's consultant did modify EV charging profiles for light-duty vehicles over time to levelize charging throughout the day later on in the forecast period, charging overnight is still fairly low.

Figure 8-4: Light-Duty EV Charging Profile, PJM Load Forecast Supplement[653]



While the new long-term forecast trajectory is heavily driven by demand from data centers and electric vehicles, whose long-term penetration is subject to uncertainty, this additional information means that the modeling results may be conservative with respect to the benefits of the policy proposals.

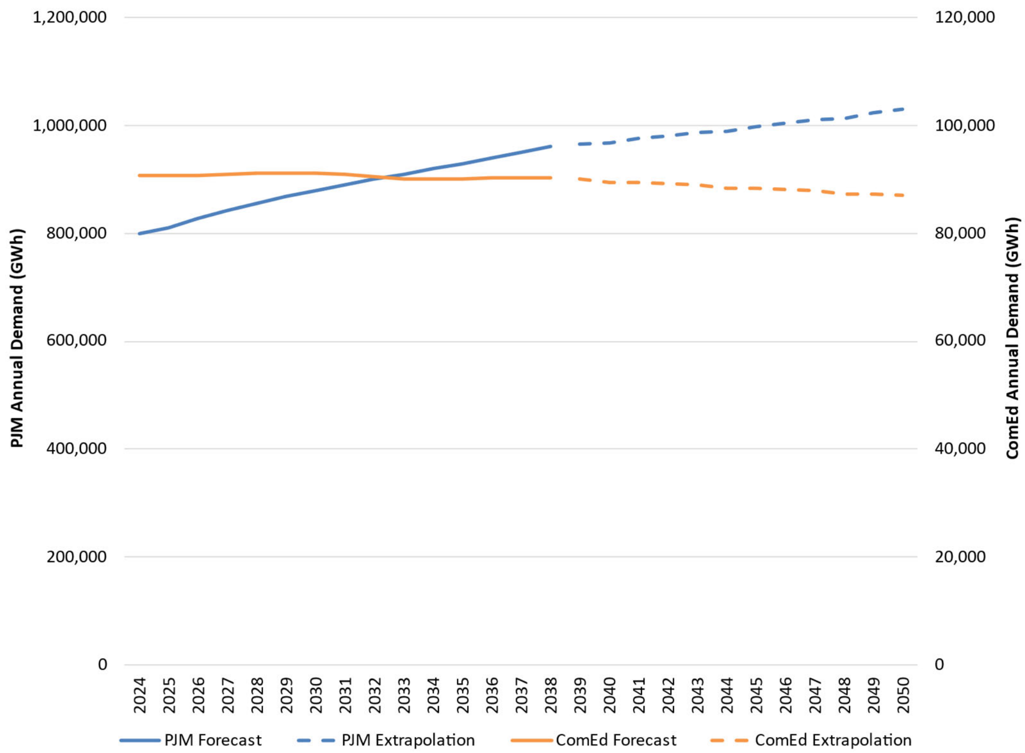
Additional efficiencies from smarter charging may allow PJM to mitigate more of the peak load contribution from electric vehicles.

Changing the electricity demand (particularly given a change of this magnitude) requires cascading changes throughout the modeling cycle. Extrapolation of load beyond the forecast period must consider whether utility-nominated adjustments to the PJM base load forecast will be transient or permanent. The load forecast permeates many other aspects of the study, namely capacity expansion. The large increase in load in PJM's latest forecast requires a full review of siting assumptions for new renewable and conventional technologies in order to meet resource adequacy and environmental goals across PJM, and would likely require substantial iteration to ensure appropriate results. While Dominion Virginia has released IRPs detailing how they will meet increased load requirements driven by data center growth, other vertically-integrated utilities in PJM have not yet considered how to manage heavy increases in demand. The new sources of load that PJM has identified do not have the same

[652] 2024 Preliminary PJM Load Forecast, November 27, 2023 presentation to the Load Analysis Subcommittee by Molley Mooney. See slides 39 and 46. 20231127-item-03---2024-preliminary-pjm-load-forecast.ashx
[653] PJM 2024 Load Forecast Supplement, January 2024, page 18. load-forecast-supplement.ashx (pjm.com)

hourly patterns as traditional demand sources, so additional review of hourly profile information would also be required for any updated modeling.

Figure 8-5: Annual Energy Forecast, PJM



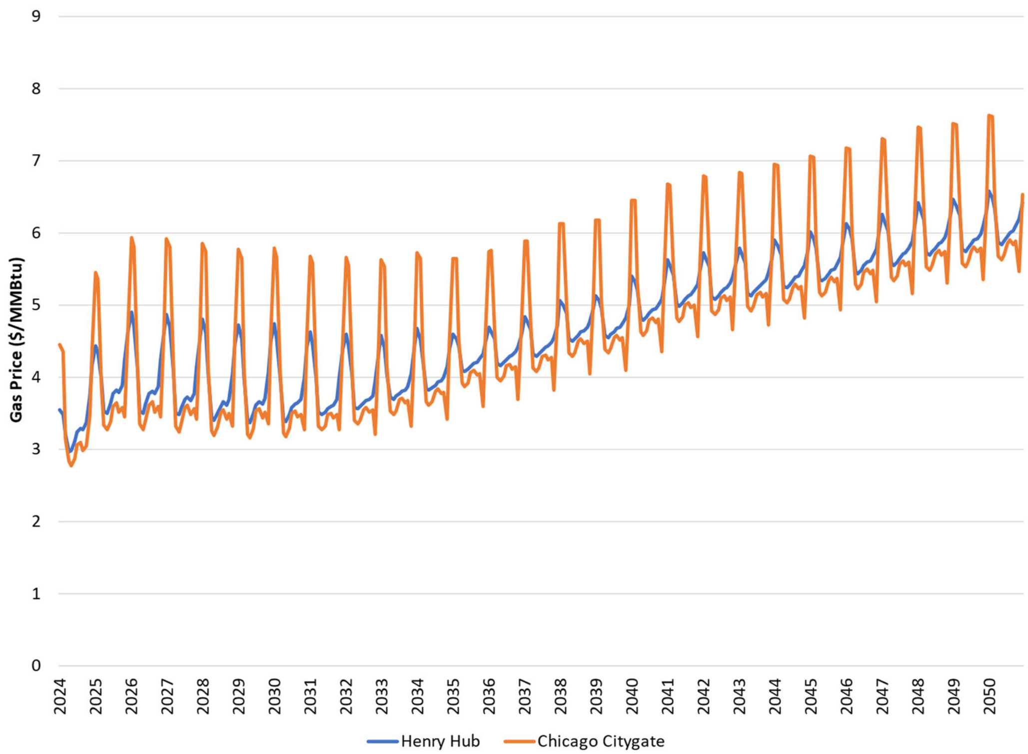
(3) Fuel Price Forecasts

Fuel prices, as delivered to generators, are forecasted for natural gas, oil products, and coal. Nuclear generators are price takers and do not have much dispatch flexibility. Nuclear fuel prices are ignored with the assumption that nuclear plants run fully-loaded aside from scheduled refueling.

(4) Natural Gas Price Forecast

The forecast of delivered natural gas prices started with NYMEX Henry Hub futures and basis projections from S&P Market Intelligence. NYMEX Henry Hub futures are available through 2035. For the years 2036 and beyond, prices were escalated annually based on the forecasted annual growth rates of the average price from EIA's 2023 Annual Energy Outlook ("AEO"), Reference and High Oil and Gas Supply cases. Basis projections are generally constant after a few years, which reflects the lack of liquidity in basis futures markets past the prompt year and significant volatility in pricing due to weather variability.

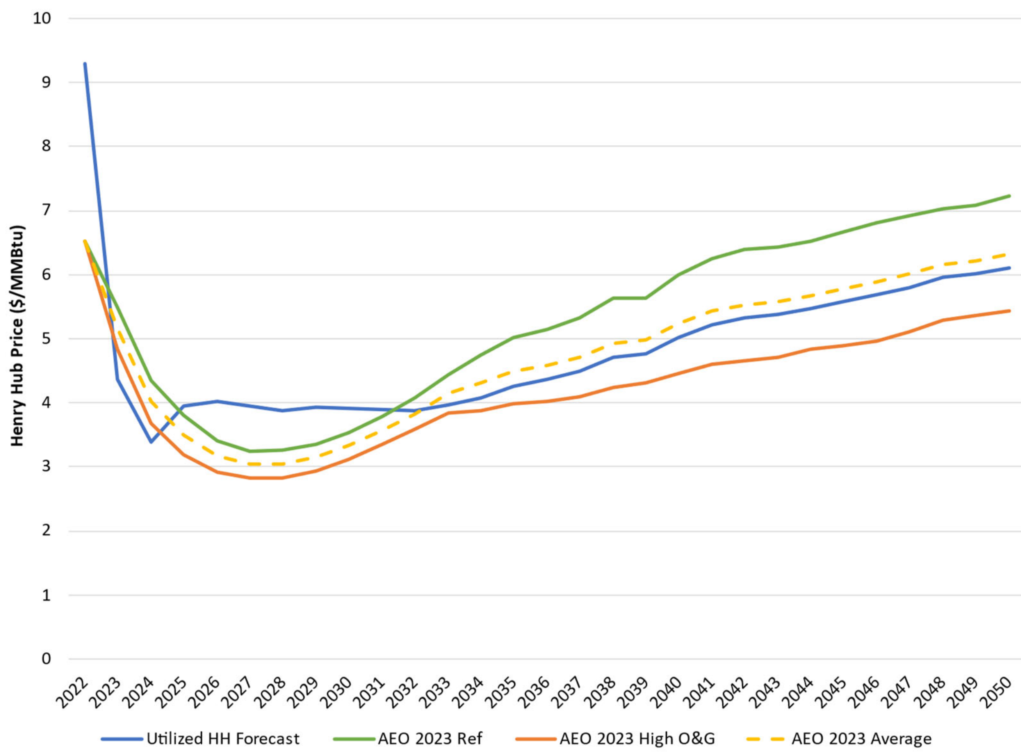
Figure 8-6: Monthly Delivered Gas Prices



In comments on the draft Policy Study, SOO Green asserted that the gas commodity price forecast used is relatively low due to the use of futures data rather than fundamentals modeling. The commenter recommended the use of a fundamentals model rather than the use of futures pricing, and recommended the use of the 2023 AEO Reference Case.[654] Comments by the Energy Storage Associations echoed this critique.[655] The gas price forecast used for this modeling was a blend of futures and fundamentals via its use of the 2023 AEO. Averaging the 2023 Reference and High Oil and Gas Supply Cases yields a similar result and respresents a blend of two fundamentals forecasts.

[654] SOO Green Comments on Illinois Power Agency Policy Study, see page 10.
[655] Energy Storage Associations Comments on Illinois Power Agency Policy Study, see pages 6-8. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240226-energy-storage-associations-comments.pdf.

Figure 8-7: Annual Commodity Price Forecast Comparison



The modeling team acknowledges that utilizing the 2023 AEO Reference Case gas price forecast would represent an increase of about 80 cents/MMBtu over the 2030-2049 period. Such an increase would raise wholesale market energy prices, and therefore increase market revenues for the policy resources.

However, the 2023 AEO is dated by a year. It was released in March 2023, and no update will be released in 2024 due to EIA's National Energy Modeling System (NEMS) receiving… "substantial updates to better model hydrogen, carbon capture, and other emerging technologies."[656] Since the AEO was published, the futures market curves for Henry Hub have decreased. While commenters claim that long-term NYMEX forwards for Henry Hub are not reactive to fundamentals, it appears that pricing has shifted substantially since the March 2023 AEO, and even since the modeling team set the gas price forecast last year. SOO Green's comments on the draft Policy Study indicated that their forecast, conducted by PA Consulting, includes two years of NYMEX forecasting, a fundamental forecast starting in four years and an interpolation of NYMEX and fundamentals forecasting in between.[657] The modeling team notes that NYMEX futures for Henry Hub have fallen from March 2023 when the AEO was released through the current comment period, which are almost a year apart, as shown Figure in resumably the step-down in near-term NYMEX futures would be a part of that forecast.

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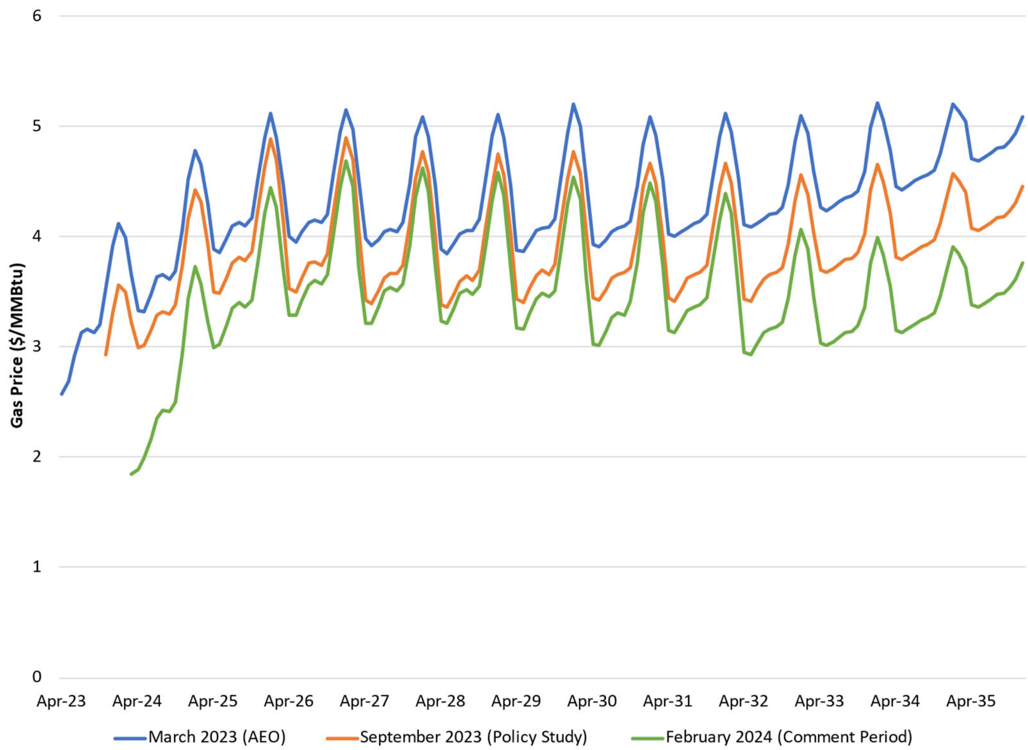
[656] U.S. Energy Information Administration, Annual Energy Outlook 2023. Main webpage here: https://www.eia.gov/outlooks/aeo/. https://www.eia.gov/outlooks/aeo/

[657] SOO Green on Illinois Power Agency Policy Study, see page 8.

Figure 8-8: Futures Price Comparison[658]



The decline in market expectations may well indicate underlying expectations for supply and demand that dictate a change in fundamental modeling in future editions of the AEO.

(5) Other Fuel Price Forecasts

Coal prices were forecasted using the 2023 AEO prices for delivered coal to electric generators as a commodity price, adjusted for recent EIA Short-Term Energy Outlook ("STEO") projections for near term. These prices are then adjusted on a unit and state level to reflect local price adders based on basin sourcing and transportation costs. These adders are developed by Energy Exemplar and are primarily based on a review of EIA-923 fuel receipts data. Coal prices are projected to decline somewhat in real terms, the long-term price increase reflects inflation. Delivered oil products prices are also forecasted based on the 2023 AEO, adjusted for recent STEO projections for near term.

(6) Scheduled Resource Additions

The model relied on Futures Siting data for Series 1A Future 1 that has been released to MISO stakeholders to identify resources for addition and retirement.[659] Given the delays in the

[658] NYMEX Futures obtained via S&P Capital IQ.

[659] See October 2, 2023 meeting materials from the Long Range Transmission Planning workshop: https://www.misoenergy.org/stakeholder-engagement/committees/long-range-transmission-planning/

PJM's BRA schedule, conventional facilities identified as "under construction" in the S&P Capital IQ power plant database are included in the base model.

The model relied on siting data from MISO Series 1A Future 1 to identify clean energy resource additions in MISO. The Futures cases include both "planned" resources, which are expected future build based on MISO member-submitted updates, and "model-built" resources, which are generic resources selected by MISO's capacity expansion model. Model-built capacity is mainly sited based on active queue positions that are not already assumed as planned capacity. Model-built capacity was not included for MISO LRZ 4 (Illinois), as these resources are expected to compete with the resources that would be built under the policy cases.

The forecast assumes that wind and solar with signed Interconnection Service Agreements ("ISAs") in PJM will be built. All queued solar projects that are not yet designated "under construction" but have an ISA in hand received a 50% derate.[660]

(7) Scheduled Retirements

The Base Case included retirements documented by the ISOs in planning documents and notices. MISO identified planned retirements in its LRTP stakeholder materials, and also provided default age-based retirement assumptions in its Futures Refresh assumptions book.[661] MISO also includes retirement of some fossil plants subject to CEJA through 2042, but further adjustments were necessary to account for undercounting in the Futures study.[662] PJM deactivations lists are reflected in the resource mix. Remaining Electric Generating Units ("EGUs") in Illinois were identified for retirement in 2045 under CEJA.[663]

The nuclear units in the study region were assumed to receive Subsequent License Renewals ("SLRs"), which generally bring them to 80 in-service years.[664] This assumption is consistent with MISO's Futures Refresh assumptions.[665]

[660] The 2022 State of the Market Report (https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec12.pdf, see Table 12-24) lists historic completion rates of 47.1% for projects that receive an FSA, and 57.4% for projects that receive a CSA.

[661] https://cdn.misoenergy.org/20230428 LRTP Workshop Item 03b Futures Refresh Assumptions Book628727.pdf, p. 3.

[662] In comments on the draft Policy Study ICJC pointed out that MISO's Future 1A does not account for all fossil retirements under CEJA, which is correct (See comment p. 5), but those retirements were accounted for in the draft study. Other sources were used to identify units and timing of CEJA retirements for MISO.

[663] CEJA defines EGUs as units with a generating capacity of 25 MW or greater. The Study utilized the 2023 Phase II report from the Energy Transition Workforce Commission to identify expected retirement dates, see Appendix 1. https://dceo.illinois.gov/content/dam/soi/en/web/dceo/events/energy-transition-workforce-commission/etwc_phaseireport.pdf

[664] Several nuclear units in PJM have applied for or intend to apply for NRC SLR, such as Peach Bottom, Surry, and North Anna. Constellation has indicated plans to apply for SLR for the Dresden facility.

[665] 20230428 LRTP Workshop Item 03b Futures Refresh Assumptions Book628727.pdf (misoenergy.org), p. 3.

Unit retirements due to other policy considerations in PJM at large were evaluated, as discussed in PJM's Energy Transition Special Report. The report estimates that as much as 24 GW of fossil capacity may retire as a result of federal, state, and corporate policies.[666]

(8) Model-Selected Additions and Retirements

Expected additions and retirements, particularly for PJM, do not cover the full study period. Additional changes to the resource mix are necessary to meet capacity requirements and serve load. Therefore, Aurora's Long-Term Capacity Expansion functionality was utilized to select resource additions and retirements beyond the scheduled changes. No new fossil capacity was allowed to be built by Aurora in Illinois. Additional information on the new build and retirement option inputs is available in Appendix E.

A projection of the PJM demand curve, the Variable Resource Requirement ("VRR"), is implemented in the Aurora model to forecast PJM capacity prices. PJM's BRA planning parameters for the 2025/2026 Delivery Year serve as the foundation of the VRR forecast. Parameters were adjusted per the latest quadrennial review and future demand from the 2023 Load Forecast Report. Specifically, an adjustment to the points on the VRR curve will be made for the RTO and each forecast LDA (MAAC, EMAAC) based on a ratio of the forecasted peak demand, net BTM solar, to the reported BRA peak for the 2025/2026 Delivery Year. LDA-level requirements were determined using data available on Capacity Emergency Transfer Limits ("CETL") and Capacity Emergency Transfer Objectives ("CETO") in the area. MISO capacity prices were estimated outside of Aurora. Over time PJM and MISO capacity markets are expected to tighten due to coal retirements and age-based attrition.

iii) Policy Proposals

(1) Offshore Wind Project in Lake Michigan

The offshore wind project modeling assumed that the project will be constructed with a 2030 in-service date, consistent with legislation. This assumption is aggressive relative to the expected development timelines but preserves a 20-year life of the project within the study period. Hourly output profiles were generated using the NREL's Wind Toolkit ("WTK") database, which includes wind resource data for the Great Lakes. WTK data for the 2011 weather year was utilized to preserve coincidence with the existing model database of renewable output profiles.

NREL's 5.5-MW reference land-based wind turbine from the NREL Annual Technology Baseline ("ATB") was utilized as the power curve input, consistent with the Current Cost Scenario in NREL's Great Lakes Wind Energy Challenges and Opportunities Assessment.[667] The Current Cost Scenario assumes that under the current technology, infrastructure and supply chain limitations, onshore wind turbines will be utilized in the Great Lakes. The

[666] energy-transition-in-pjm-resource-retirements-replacements-and-risks.ashx, p. 8.

[667] https://www.nrel.gov/docs/fy23osti/84605.pdf See table 6 on page 99.

offshore wind project was modeled with a nameplate capacity of 200 MW and with adjustments for losses (electrical, wake, availability, etc.) given this nameplate capacity to match the energy target in the legislation.

For the 200 MW offshore wind fixed-bottom projects, CapEx and OpEx data from the March 2023 Great Lakes Wind Energy Challenges and Opportunities Assessment from NREL was utilized.[668] The CapEx values had to be recalibrated to reflect the current technology scenario, rather than the advanced research technology scenario (which reports far lower CapEx values). The cost values in the ensuing tables & charts reflect a fixed-bottom project option.

The offshore wind project is assumed to capture the 30% Investment Tax Credit ("ITC"), which will reduce the costs of investment.[669] Diamond Offshore Wind noted that if land-based turbines are used, they may contribute to meeting the 10% ITC domestic content bonus, which would further reduce capital costs.[670] Additional manufacturing for the onshore wind supply chain is being located in the United States, such as nacelle manufacturing for large turbines.[671] However, the domestic content requirements will grow to 55 percent for offshore wind projects which begin construction after 2027.[672] Given the uncertainty around whether large portions of the offshore wind project will utilize domestic content, this bonus was not part of the cost assumption. Based on the currently indicated points of interconnection, the 10% ITC bonus for brownfield site development is not expected to be captured.

(2) SOO Green Renewables and HVDC Transmission

SOO Green's supplemental response to the IPA's questions estimated commercial operation of the HVDC facility would occur in 2030, and renewable projects in Iowa serving the line would enter service in early 2029. For simplicity of modeling and reporting, all components of this policy option were assumed in service at the beginning of 2030. Based on responses in the initial response memorandum, the HVDC transmission is represented as a 2,100 MW one-way link between the Alliant West area in MISO LRZ 3 and the ComEd zone in PJM.[673] The line will have losses of about 3.1%; effectively about 2,035 MW will be received at maximum flow across the line.

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[668] https://www.nrel.gov/docs/fy23osti/84605.pdf.

[669] In the draft Policy Study released on January 22, 2024, the ITC was inadvertently excluded from the modeling. This has been corrected for the final Policy Study.

[670] Diamond Offshore Wind Comments, see page 6. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240213-diamond-offshore-wind.pdf.

[671] Inflation Reduction Act Spurs Breakthrough in Domestic Wind Production, U.S. Department of Energy Office of Energy Efficiency & Renewable Energy, December 14, 2023.

https://www.energy.gov/eere/articles/inflation-reduction-act-spurs-breakthrough-domestic-wind-production.

[672] See IRS Notice 2023-38, page 5. https://www.irs.gov/pub/irs-drop/n-23-38.pdf

[673] Though the line will have bi-directional capability, the commercial obligations and grid limitations will limit reversal of flow.

SOO Green provided an optimized generation portfolio made up of wind, solar, and battery storage. Renewable generation profiles from the portfolio analysis were utilized, and storage dispatch reflected charging constraints on battery storage consistent with assumed restrictions. Battery storage is restricted to only charge when overgeneration from the supply portfolio is available, and to only discharge when transmission headroom is available.

A constraint ensures a minimum flow on the HVDC line at the hourly output of the green supply portfolio (up to the maximum capacity of the line). This constraint reflects the incentive to deliver renewable energy across the transmission line in order to receive Indexed REC revenues. Additional deliveries can be made into ComEd if the economics are warranted but are not counted as "clean." Incremental deliveries of system energy would not receive contract payments under an Indexed REC structure.

The SOO Green line bears many similarities to the Clean Path NY ("CPNY") transmission line, as demonstrated in the table below. CPNY was a selected project in NYISO's Tier 4 solicitation, which SOO Green has cited as an example of a potential approach for commercialization.[674] Rather than attempting to develop a bottoms-up estimate of the HVDC line cost and associated renewable energy, the CPNY strike price was adjusted to determine potential project costs.

Given the large size and concentrated investment into a single contract, Illinois utilities may begin collections for the SOO Green project in advance of delivery of clean energy across the line. The magnitude, timing, and financial treatment of advance collections is uncertain, so near-term rate effects from such treatment were not quantified.

(3) Energy Storage Systems Development

For the energy storage systems development targets, storage resources were added to meet the following procurement targets:

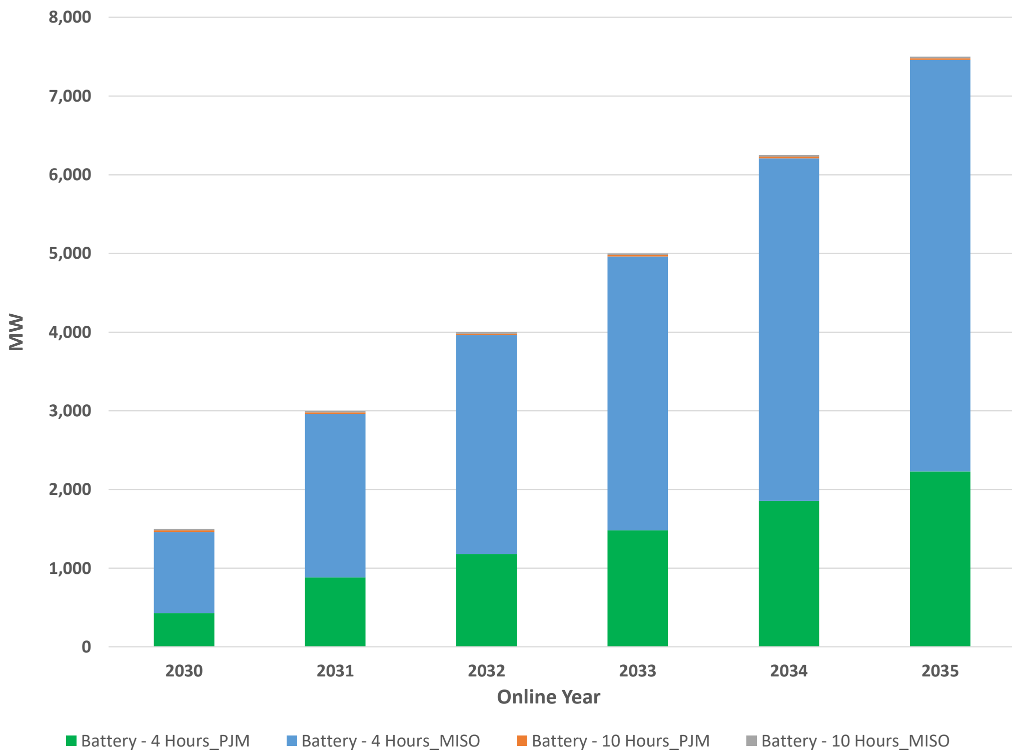
1. 3,000 MW by 2026,
2. 5,000 MW by 2028, and
3. 7,500 MW by 2030.

Accounting for development time and delays in implementing the legislation, deployment assumed was:

1. 3,000 MW by 2031
2. 5,000 MW by 2033, and
3. 7,500 MW by 2035

[674] Information on NYSERDA's Tier 4 solicitation, including public bid information and contracts, is on NYSERDA's web site: https://www.nyserda.ny.gov/All-Programs/Large-Scale-Renewables/Tier-Four/Solicitation-and-Award.

Figure 8-9: Deployment Schedule for Energy Storage Systems



Deployment targets were met at the beginning of the calendar year, rather than the delivery year, to simplify reporting processes. Development was phased in over intermediate years. SB 1587 prescribes that "[f]or all solicitations prior to the delivery year 2028, the Agency shall strive to procure at least 70% of energy storage credits from energy storage systems interconnected to MISO, and at least 10% of energy storage credits from energy storage systems located within a city with population of more than 1,000,000 people and interconnected to PJM Interconnection, LLC." From a zonal modeling perspective, those requirements translate to at least 70% in LRZ 4 and 10% in ComEd, with 20% unspecified. The additional 20% was sited in ComEd.

The duration of energy storage systems was assumed to be 4 hours, with the exception of two 20 MW, ten-hour units that will be developed under the long-duration/multi-day carveout in SB 1587.[675] Round-trip efficiency was assumed to be 85%, consistent with cost projections used in the NREL ATB.[676]

For the 4-hour and 10-hour MISO and PJM storage systems, CapEx and OpEx data from the NREL 2023 Annual Technology Baseline (ATB) database for utility scale battery storage was

[675] SB 1587 gives the IPA discretion to adjust the duration requirements for solicitations in delivery year 2028 and later, but capacity accreditation factors for 4-hour resources in PJM and MISO are projected to be robust (75% or greater). Given that the main driver of cost for current energy storage systems is the storage capability, a 6-hour or 8-hour duration will not receive additional capacity revenue commensurate with costs.

[676] Cost Projections for Utility-Scale Battery Storage: 2023 Update, Cole and Karmakar, National Renewable Energy Laboratory issued June 2023. See page 8. https://www.nrel.gov/docs/fy23osti/85332.pdf

utilized.[677] The NREL ATB database provides CapEx and Fixed O&M estimates benchmarked with industry and historical data. The projects are planned to be built over several years – the costs per project decline by year. The conservative scenario (a 4-hour storage project built in 2030 has CapEx and FOM costs 29% and 19% lower respectively when compared to a corresponding a 4-hour storage project built in 2023; future projects after 2030 observe an annual drop of 1.8% CapEx and 0.7% FOM) was selected.[678] The cost data is adjusted for location using data taken from the EIA Assumptions to the 2023 AEO: Electricity Market Module.[679]

(4) Distributed Scale Paired Storage Sensitivity

Small-scale storage systems paired with distributed solar were considered as an additional policy option to consider incrementally with the 7,500 MW goal. 1,000 MW of four-hour storage was modeled as in-service in 2030 to reflect additional storage realized by pairing with behind-the-meter solar. This amount was not discretely or separately modeled in Aurora, but rather results from the production cost modeling for the 7,500 MW storage policy were scaled down to match benefits to the estimated adoption and costs shown below.

Over the next two delivery years, the 2024 Long-Term Renewables Procurement Plan proposed 800 MW of program block capacity to be procured through Illinois Shines.[680] The block capacity for procurement was assumed to persist through the 2030 delivery year, which would incent about 5,600 MW of capacity to be procured to provide 8.3 million RECs. Of this quantity, about 20% is assumed to be small-scale solar, and the rest is assumed to be commercial scale solar.[681] Per NREL, battery nameplate for smaller residential scale systems is typically installed at a 5 kW battery to 8 kW PV and inverter size.[682] 200 MW of paired storage at smaller scale was assumed, which implies about a 30% adoption rate. Commercial paired storage are more typically paired at a one to one ratio of battery to solar capacity.[683] The remaining 800 MW of paired storage was assumed at commercial scale, which implies about a 20% adoption rate. These adoption rates are optimistic relative to recent history,

[677] https://atb.nrel.gov/electricity/2023/data

[678] https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage

[679] Published March 2023. https://www.eia.gov/outlooks/aeo/assumptions/

[680] 2024 Long-Term Plan, Illinois Power Agency, October 20, 2023. See Tables 7-1 and 7-2.

Microsoft Word - 2024 Long-Term Plan (20 Oct 2023 515pm).docx (illinois.gov)

[681] All of the Small Distributed Generation category, and one eighth of the Equity Eligible Contractor Category, is assume to be small scale solar. Large DG, community solar, and Public Schools were assumed to be commercial-scale systems.

[682] Ramasamy, Vignesh, Zuboy, Jarett, O'Shaughnessy, Eric, Feldman, David, Desai, Jal, Woodhouse, Michael, Basore, Paul, and Margolis, Robert. 2022. "U.S. Solar Photovoltaic System and Energy Storage Cost Benchmarks, With Minimum Sustainable Price Analysis: Q1 2022". United States. See Table 7. https://doi.org/10.2172/1891204. https://www.osti.gov/servlets/purl/1891204.

[683] *Id,* see table 9.

which suggests about a 10% attachment rate for residential and 5% for non-residential installations.[684]

Given that storage charging often occurs during hours with solar generation, charging was not restricted to a specific "paired" solar generator. Round trip efficiency was assumed to be identical to front-of-meter resources and cycling remained limited to once daily.

For the 4-hour MISO and PJM storage systems, CapEx and OpEx data from the NREL 2023 Annual Technology Baseline (ATB) database for residential (200 MW) and commercial (800 MW) battery storage was utilized.[685] The NREL ATB database provides CapEx and Fixed O&M (FOM) estimates benchmarked with industry and historical data. The projects are planned to be built in 2030. The conservative scenario (both commercial and residential 4-hour storage projects built in 2030 have CapEx and FOM costs that are19% lower respectively when compared to corresponding 4-hour storage projects built in 2023; future projects after 2030 observe an annual drop of 0.3% for both CapEx and FOM).[686] The cost data is adjusted for location using data taken from the EIA Assumptions to the 2023 AEO: Electricity Market Module.[687]

No cost synergies for paired storage were included in the cost modeling, but the Investment Tax Credit was applied to the cost values.

iv) Production Cost Modeling Results

(1) Base Case Results

Simulation modeling showed that when the bulk of Illinois fossil plants retired due to CEJA in 2045, energy adequacy problems were created in the ComEd zone and LRZ4. The zones could not meet peak load with expected renewables and storage on hand, subject to transmission import limits. Given that storage is one of the policy options tested in but-for cases, the modeling team elected to "repower" about 8.5 GW of fossil capacity retired under CEJA to Zero Emissions Fuel ("ZEF") units, the bulk of which is switched over in 2045. These units were assumed to have zero CO_2 emissions and maintain their emissions rates for other pollutants (assuming that these values are driven in part by air permit limits). ZEFs have a high fuel price (averaging about $45/MMBtu during the 2040-2050 period).[688] These resources are called on sparingly during the production cost modeling, which effectively represents a 50/50 peak condition, but would be critical to support Illinois during stressed

[684] Max Issokson, Distributed solar-plus-storage holds much promise, but where does it stand today? Published August 10, 2023 by Wood Mackenzie.

https://www.woodmac.com/news/opinion/distributed-solar-plus-storage-holds-potential/

[685] https://atb.nrel.gov/electricity/2023/data

[686] https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage

[687] Published March 2023. https://www.eia.gov/outlooks/aeo/assumptions/

[688] The fuel costs for zero emissions fuel units is based on hydrogen. The Hydrogen price was derived from NYSERDA's Climate Action Council Scoping Plan and the associated Integration Analysis. See data annex:https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/IA-Annex-1-Inputs-and-Assumptions-2022-revised.xlsx

system conditions. For production simulation modeling of long-term transitions to non-carbon emitting future generation mixes, in the outer years of the modeling horizon it is not unusual for the modeling to show generation shortfalls for limited periods of time (usually a few hours) during periods with high demand and sustained low renewable output, which limits storage ability to balance load and clean energy. Since the future peaking resources necessary to cover these shortfalls have not been determined, the modeling assumes that proxy peaking units that do not emit carbon will be used. In this instance ZEFs are dispatched (in only a handful of hours) to meet high demand when renewable output is low. This technique is consistent with modeling practices that system operators have adopted to consider a full transition away from fossil fuels. MISO utilized Flexible Attribute Unit, or "Flex" technology in their Futures report to manage energy shortfall issues that were identified during production cost modeling:

> *These "Flex" units are proxy resources that refer to a non-exhaustive range of existing and nascent technologies, representing potential generation that is highly available, highly accredited, low- or non-carbon emitting, and long in duration. As a proxy, potential Flex resources could be, but are not limited to: RICE1 units, long-duration battery (>4 hours), traditional peaking resources, combined-cycle with carbon capture and sequestration, nuclear SMRs, green hydrogen, enhanced geothermal systems, and other emerging technologies.*[689]

Certain costs related to these systems, cited from the NREL ATB, are provided below for illustrative purposes.

Table 8-8: Cost Parameters for Potential ZEF Technologies

Technology	Overnight Capital Costs ($/kW)	Fixed O&M ($/kW-yr)	Fixed O&M ($/MW-day)	Variable O&M ($/MWh)	LCOE ($/MWh)	Maturity
NG Combined Cycle H-Class integrated retrofit 95%-CCS	1046	58	158	4.33	Not Reported	N
NG Combined Cycle (H-Frame) 97% CCS	2122	56	153	4.26	Not Reported	N
Nuclear - Small Modular Reactor	7483	119	325	3.13	88	N
Utility-Scale Battery Storage - 10Hr	3263	82	223	0.00	Not Reported	Y

[689] MISO Futures Report, Series 1A, published November 1, 2023. See pages 2-3. Series1A_Futures_Report630735.pdf (misoenergy.org). RICE1 unit are reciprocating internal combustion engines.

Notably, most of these technologies are not considered mature and face significant uncertainty around siting and commercialization. While storage is an available technology, it may not be able to cover sustained lulls in renewable generation. In addition, CCS and Nuclear SMRs represent baseload technologies that would run at a high capacity factor and reduce energy prices if included. ZEFs have a limited impact on energy price formation and ensure that modeled energy market pricing is almost entirely set by commercially mature technologies with better-known costs and operational regimes.

In comments on the Policy Study, the Energy Storage Associations argued that the introduction of ZEFs "may be suppressing the projected overall value of energy storage in the Draft Study by as much as hundreds of millions of dollars a year."[690] Given that the capacity factor for ZEFs averages 0.11% from 2040-2044, and 0.56% from 2045-2049, and the dispatch costs of ZEFs are high per the fuel price assumptions noted above, the ZEFs as formulated are meant to affect energy market dispatch as little as possible.

The state of New York has similar mandates to eliminate emissions from the electric grid via the Climate Leadership and Community Protection Act as Illinois has under CEJA. The New York Independent System Operator (NYISO) has therefore faced similar challenges to MISO in its economic planning forecasts regarding reliability during the clean energy transition, and has adopted a similar modeling approach to MISO by including a category of "dispatchable emissions-free resources" in their modeling that are functionally equivalent to ZEFs used in the modeling for this study [691]

As discussed further in Appendix E, this approach has been used in many other circumstances, including by Ameren Missouri, Pacificorp, Idaho Power, Dominion Virginia Power, Eugene Water and Electric, ISO-NE, and a decarbonization study prepared for ComEd.

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[690] Energy Storage Associations Comments to the IPA Draft Policy Study, page 10. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240226-energy-storage-associations-comments.pdf

[691] "Substantial dispatchable emission-free resources (DEFR) will be required to fully replace fossil fueled generation, which currently serves as the primary balancing resource. Long-duration, dispatchable, and emission-free resources will be necessary to maintain reliability and meet the objectives of the CLCPA." 2021-2040 System & Resource Outlook (The Outlook), New York Independent System Operator, September 22, 2022. See pages 29-30. https://www.nyiso.com/documents/20142/33384099/2021-2040-Outlook-Report.pdf/a6ed272a-bc16-110b-c3f8-0e0910129ade

Figure 8-10: Cumulative MISO Resource Addition and Retirement

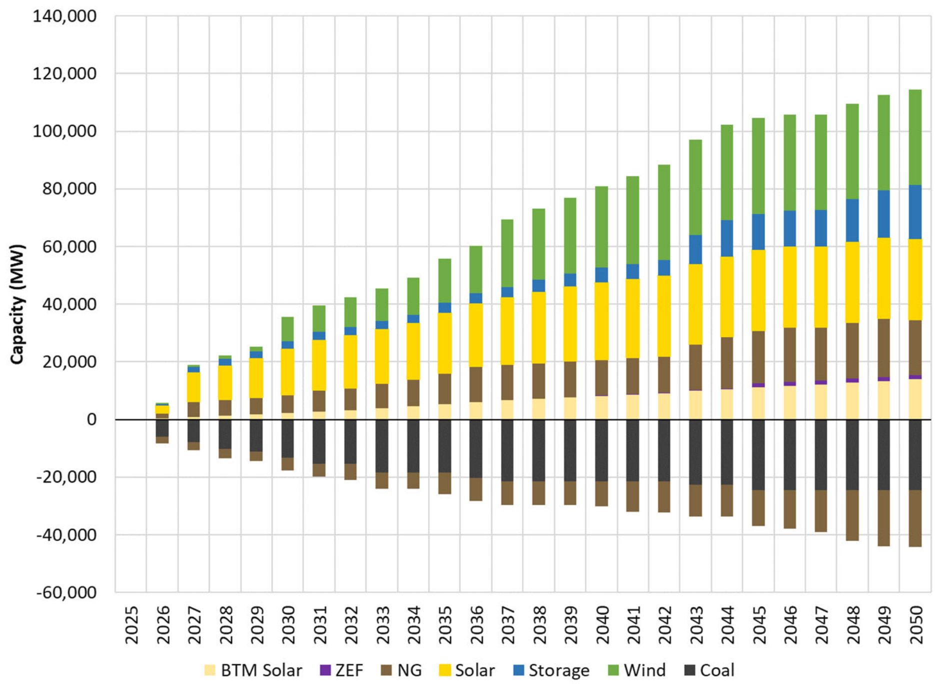
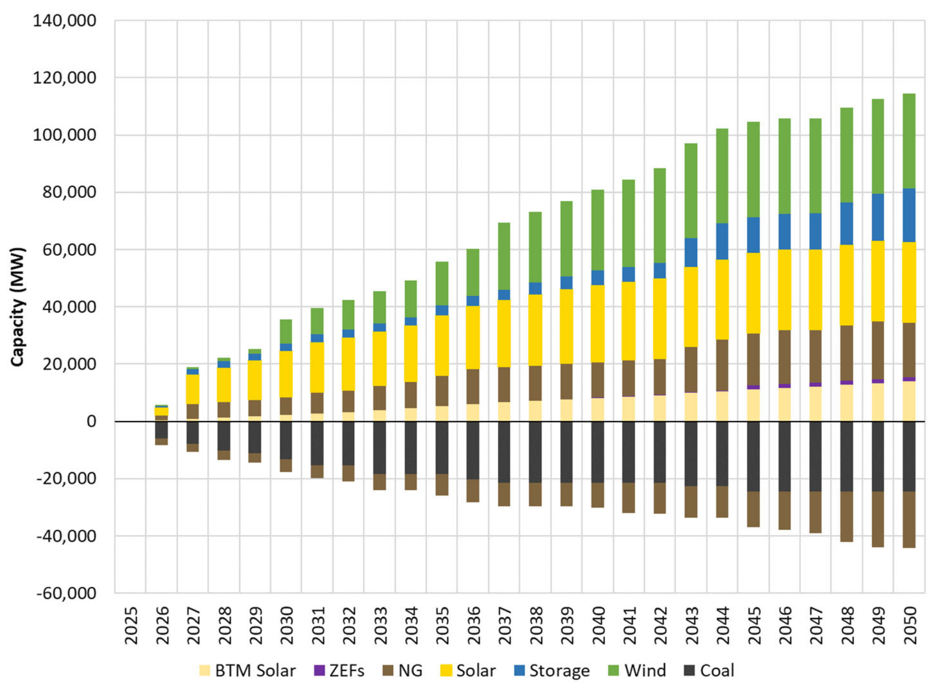


Figure 8-11: Cumulative PJM Resource Addition and Retirement



In the PJM region, there is a substantial surge in both behind-the-meter solar and utility-scale solar, amounting to a 50 GW increase by the year 2050. Additionally, there is a cumulative addition of 15.9 GW in offshore wind capacity by the same year.

Figure 8-12: Illinois Capacity by Fuel Type

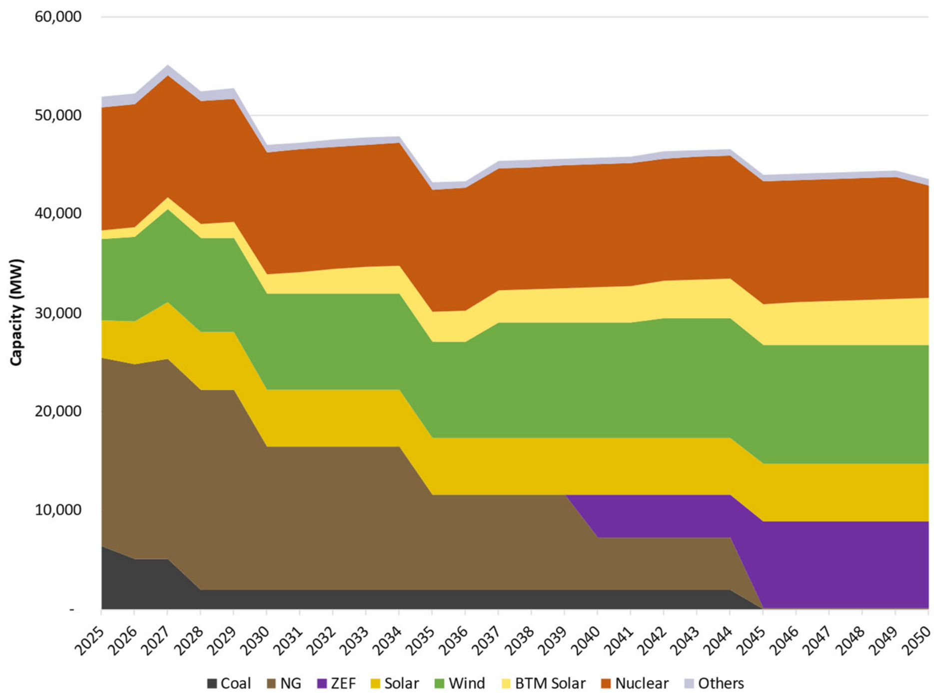
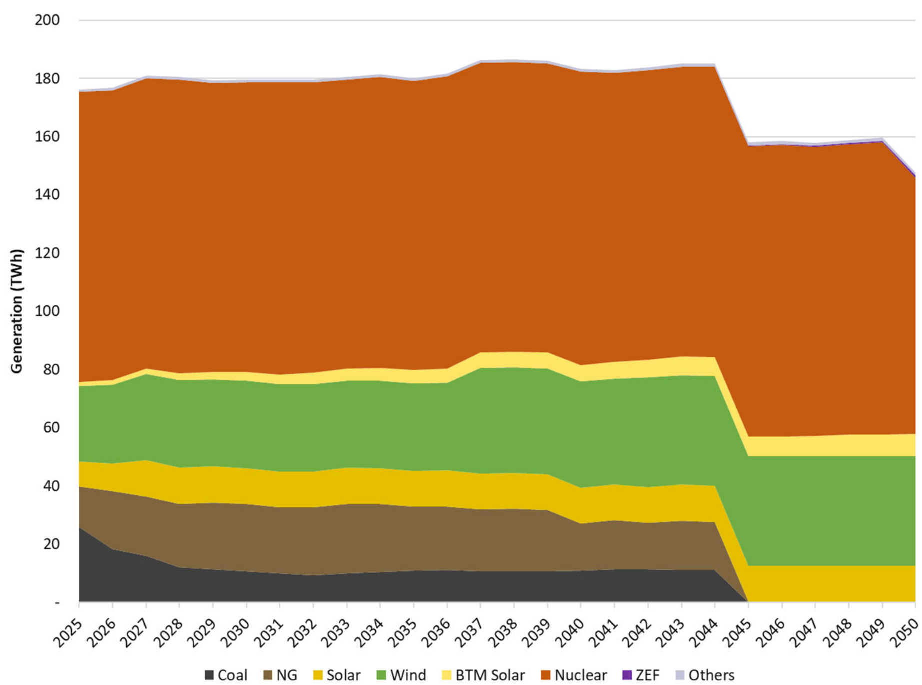


Figure 8-13 Illinois Generation by Fuel Type

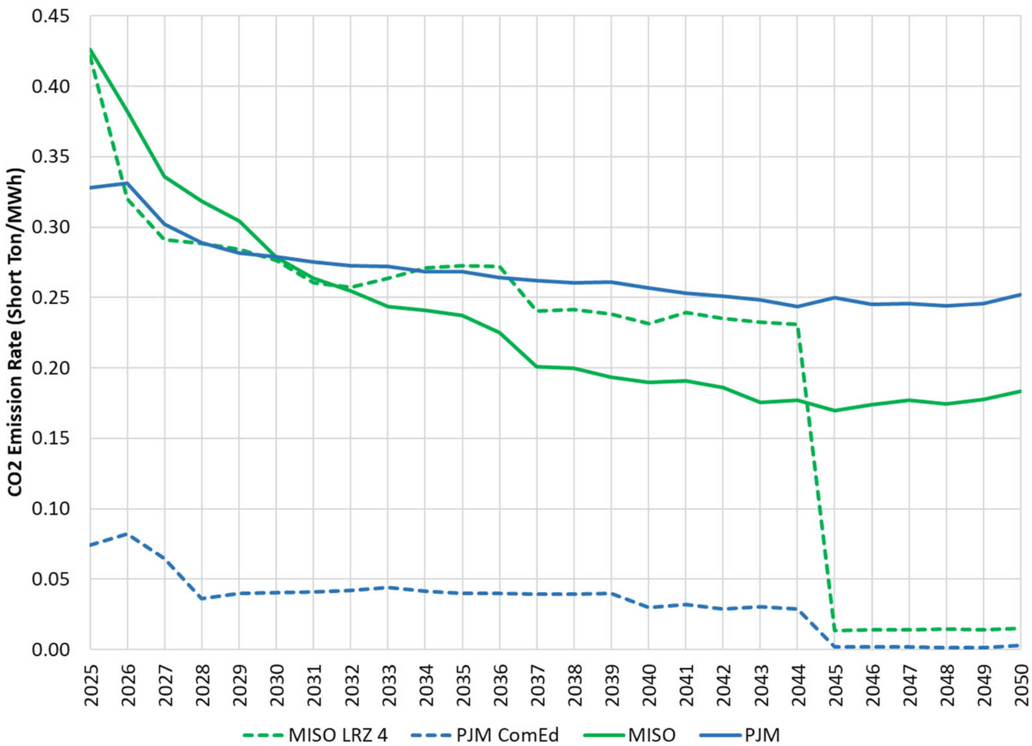


The "Others" category includes Storage, Oil, Hydro, Jet Fuel, Biomass, and Refuse. Per the emission reduction mandates of CEJA, approximately 6.2 GW of gas and oil capacity would be retired by 2030. Another 4.9 GW of gas capacity would be retired by 2035, another 4.3

GW by 2040, and then the remaining 7.2 GW of fossil EGUs retired in 2045. Storage modeled as supply only accounts for 173 MW in the Base Case. An additional behind the meter storage generation value of 120 MW in 2038 is assumed in PJM's 2023 Load Forecast Report.[692] No specific storage forecast was extrapolated for future years, though reductions in peak demand are embedded in the load forecast values. 4.3 GW of ZEFs are added by 2040, though dispatch from 2040-2045 is limited. 8.8 GW of ZEFs are part of the resource mix from 2045 on.

(2) Emissions

Figure 8-14: CO_2 Emission Rate



Due to the shift in the resource mix towards cleaner energy sources, the CO_2 emission rate has shown a consistent decline over the studied period. MISO exhibits a more pronounced and steeper decline compared to PJM due to a more aggressive postulated renewable buildout. In MISO LRZ 4, there is a step change in 2045, attributed to the phased-out fossil plants, particularly coal units that are allowed to remain in-system. The CO_2 emissions rate for MISO shown in Figure 8-14 has decreased relative to the draft Policy Study due to an error in Energy Exemplar's database, which mis-classified the location of one fossil plant, and has since been corrected. The remaining emissions in MISO and PJM after 2045 are

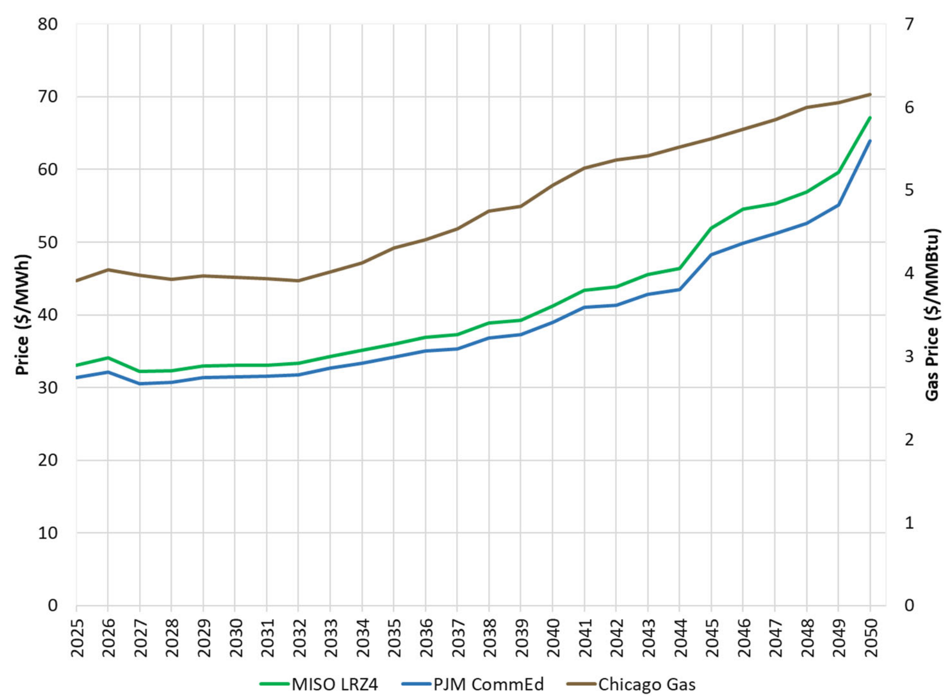
[692] See materials from PJM's Load Analysis Subcommittee, November 29, 2022 presentation. https://www.pjm.com/-/media/committees-groups/subcommittees/las/2022/20221129/item-03d---state-zonal-breakdown---ihs-capacityatpeak-solar-battery.ashx

attributable to smaller generators that do not meet the size requirements for CEJA and therefore are not closed.

v) Energy Prices

Throughout the study period, the relationship in the annual average energy prices remains consistent among MISO LRZ 4, ComEd, and Chicago gas prices. Specifically, the price in MISO Zone 4 tends to be approximately \$2.5/MWh higher than in the ComEd zone. Following the retirement of fossil generation under CEJA, there is a widening of the price gap, reaching \$4.2 per MWh. MISO LRZ 4 and PJM ComEd both undergo a comparable average annual price increase of approximately 2.3%. However, there is a significant spike in the annual power price growth rate in 2045 to 11%, attributed to the impact of CEJA which makes import constraints into Illinois zones bind more often, and takes gas generation off the margin. In contrast, the Chicago gas price sees a slightly lower average annual increase, specifically at 1.8%. Energy prices projected for 2030 are similar to the last 12 months of power prices at the PJM Chicago Hub, which averaged \$30/MWh, or the MISO Illinois Hub, which averaged \$33/MWh.[693] Power prices increase with gas commodity from 2025-2040, and experience further pressure from load growth and fossil retirements by the end of the Study Period.

Figure 8-15: Zonal Energy Price

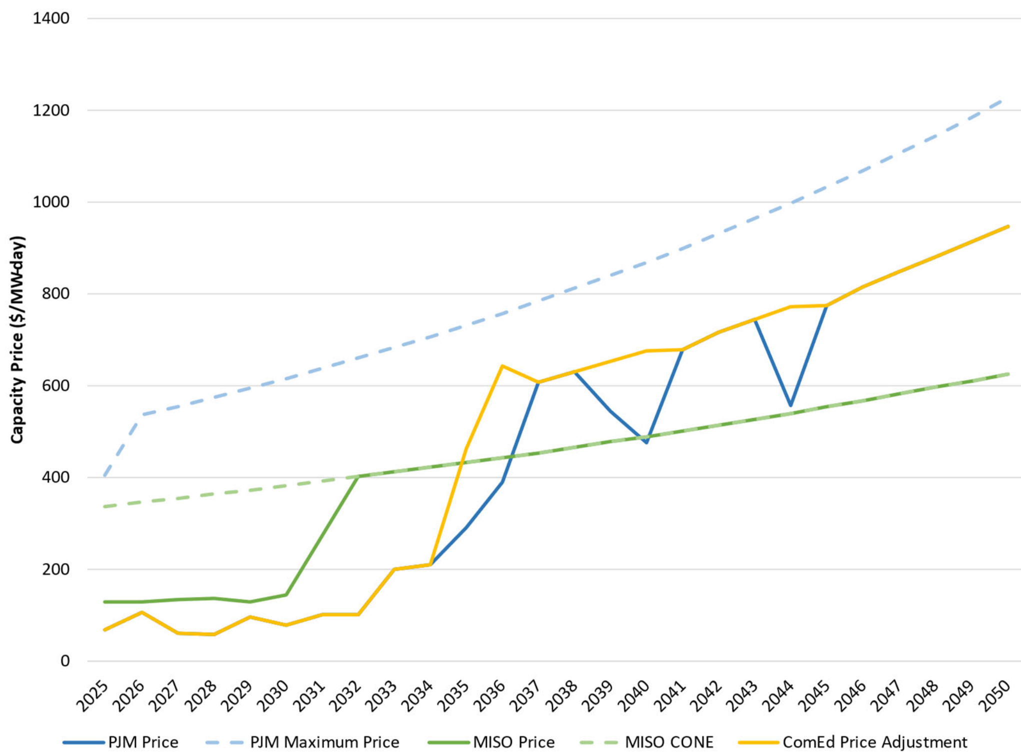


[693] Prices sourced from S&P Capital IQ.

vi) Capacity Prices

Capacity prices are very difficult to forecast past the prompt year (i.e. the next delivery year that will be cleared via auction). PJM and MISO are continually changing the market rules in their tariff. Both RTOs have recently added seasonal components to their capacity markets, and MISO has currently made a proposal to add a sloped demand curve to their capacity auctions. Both markets utilize the CONE, the projected costs of a generic new unit, as a guidepost for the market price when resource margins are tight or deficient. Since capacity is supposed to represent the "missing money" to secure investment in new (and existing) resources to provide resource adequacy, the logic is that the price cannot be higher than the cost of a new generating unit that is well-suited to provide capacity. As a first approximation, it follows that when an RTO faces tight capacity supply conditions (i.e. just enough resources to meet peak demand and reserve margin), the capacity price will rise to be CONE or net CONE after other revenues from wholesale markets (energy and ancillary services) are credited out.

Figure 8-16: Capacity Price Forecast



Aurora's capacity expansion functionality was utilized to determine capacity prices for PJM. For MISO, no long-term case was modeled to determine capacity prices, since the forecast started with a static resource expansion from MISO Future 1 modeling results. However, MISO Futures modeling indicates that surplus accredited capacity will dwindle over time, with the RTO becoming tight starting in 2032.[694] Prices were assumed to clear at CONE, MISO's administrative price ceiling, thereafter and CONE was escalated at inflation. Both RTOs will need to add capacity to counterbalance fossil unit attrition, particularly coal-fired steam turbines facing new environmental rules and state and utility initiatives.

In comments on the draft Policy Study, the Energy Storage Associations recommended including "… a historically-based price escalator to ComEd Zone capacity prices." [695] The report cited the average differential between the RTO and ComEd clearing prices from the 2018-2019 to 2023-2024 delivery years, which averaged $56.52/MW-day.[696] It is unclear why the clearing price from the 2024-2025 BRA was omitted from this analysis; the most recent BRA cleared at $28.92/MW-day in RTO, and ComEd did not separate in price.[697] Over the last two years, the ComEd price has not separated from the RTO, and in 2022-2023 the premium was relatively small ($18.96/MW-day). In that year, several nuclear facilities failed to clear the BRA which have since appeared to clear.[698,699] More recent auction outcomes do not suggest that price separation should be factored in using a historical escalator.

The assumed CONE values that drive the forecasts are conservative in nature, as CONE may become more expensive in the face of decarbonization initiatives. However, some adjustments to the forecasted capacity price are warranted. Most directly in this case, on January 19, 2024, FERC issued an order accepting PJM's tariff revisions to separate ComEd into a new CONE Area 5 from CONE Area 3.[700] Due to the recency of that order, the draft Study was not updated to reflect that new CONE. To account for the expected retirement of the CONE combined-cycle unit in 2045 under CEJA, the assumed asset life of the resource will be stepped down from the 20-year default value. In that proceeding, a PJM witness estimated that by 2029/2030, the CONE Area 5 would have an 8.2% higher Gross CONE value due to the reduction in asset life to 15.5 years from the standard 20-year assumption.[701] Based on a review of the workpaper source for those calculations, by the 2034/2035 delivery year (10.5 year asset life, ComEd would have an 28.6% higher CONE than the neighboring

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[694] MISO Futures Report, Figure 51.

20231002 LRTP Workshop - Draft Series1A Futures Report630365.pdf (misoenergy.org)

[695] Energy Storage Associations Comments to the IPA Draft Policy Study, page 10.

[696] *Id.*page 9, table 3.

[697] PJM BRA Report, see page 5, table 2.https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2024-2025/2024-2025-base-residual-auction-report.ashx

[698] S&P Global Market Intelligence, "3 Exelon nuclear plants fail to clear PJM Capacity Auction", accessed Feburary 27, 2024. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/3-exelon-nuclear-plants-fail-to-clear-pjm-capacity-auction-64835071

[699] See BRA Report, page 11, Table 7.

[700] See Order Accepting Tariff Revisions, issued January 19, 2024 in FERC Docket ER24-462-000. https://www.pjm.com/directory/etariff/FercOrders/7129/20240119-er24-462-000.pdf

[701] See affidavit of Gary Helm, filed November 21, 2023 in FERC Docket ER24-462-000, Table 1 on page 6. https://www.pjm.com/directory/etariff/FercDockets/7745/20241121-er24-462-000.pdf

regions.[702] Given the higher CONE value (and hence higher VRR curve assumptions) utilized in the Area 5 filing, the modeling team re-assessed whether ComEd would separate from the RTO forecast before PJM at large required new build and the final Policy Study includes the use of an adjusted CONE for ComEd. The VRR curves were estimated using the escalating CONE adjustment per economic life, and the supply demand balance indicated that the ComEd price would separate following the second wave of fossil fuel retirements in 2035. The clearing price was not assumed to separate indefinitely as PJM at large clears around its reserve margin from 2037 on and the Area 5 CONE premium eventually would be replaced by another reference unit calculation. The reductions in capacity price seen in 2038-2040 and 2044 were eliminated, as ComEd would not be in a surplus condition as the RTO was in those periods.

As the economic life of the combined cycle reference unit used in the Area 5 CONE calculation dwindles, it is likely that capacity prices are benchmarked by a clean energy asset in PJM that becomes more competitive. NYISO has also utilized a short amortization period for its CONE calculation for fossil generators to account for Climate Act compliance, which requires a zero-emissions power grid by 2040. NYISO is currently considering battery storage technologies and zero-emissions retrofits for gas turbines in its current CONE review cycle.[703] As battery storage may become the "reference" CONE unit in PJM or MISO in the future, capacity markets will provide a strong revenue stream to make prospective storage projects viable.

Indirect (market price) impacts of adding incremental capacity into MISO and PJM were not estimated. Perturbing the capacity expansion model makes creating a "but for" test for energy and environmental effects difficult. Resource additions may be deferred and retirements accelerated in response to a new addition, which may lead to limited or no net change in prices. Changes to the resource mix besides the policy cases considered would also reduce the energy market impacts. While there is some indirect capacity market benefit, counting such a benefit to be wholly additive against a "but-for" energy market test inflates the combined value of energy and capacity market impacts. In comments on the draft Policy Study, SOO Green raised the indirect capacity price benefit of the project and touted the use of PA Consulting's RPM model in bid advocacy for various clean energy projects.[704] While bidders may have adopted these price impacts in proposal narratives supporting project selection, state commissions have not used them as the basis for project selection or the calculation of rate impacts. The New York State Public Service Commission did not include

[702] See CONE workpapers: https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220520-special-session/pjm-2022-cone-workbook-ct-cc-battery-storage----public-version----informational-only.ashx after adjusting the debt and equity rates to match footnote 11 of the Helm affidavit, the asset life factor calculation could be reasonably approximated.

[703] NYISO 2025-2029 ICAP Demand Curve Reset, November 8, 2023 presentation to the ICAP Working Group Meeting by 1898 Co. https://www.nyiso.com/documents/20142/41049783/2025-2029 DCR - BMcD Presentation 11082023 ICAPWG Draft v3.pdf/aca3178b-3b86-5e31-cd38-fa8ac8bea06e

[704] PA Consulting identified the potential wholesale capacity cost savings of the SOO Green project as approximately $4.02 billion in nominal dollars from 2030-2049 using its RPM model. The modeling team does not have a separate Reliability Pricing Model (RPM) simulation model in place. See SOO Green comments, pages 5-6.

capacity price benefits in their calculation of rate impacts.[705] The New Jersey Board of Public Utilities does not use capacity price suppression as a basis for their selection of offshore wind projects.[706] The Maryland Public Service Commission did consider reductions in energy and capacity prices, but consultants for Maryland Staff and Skipjack did not place any value on capacity price reduction in their impact calculations.[707] Project developers have a strong incentive to estimate large energy and capacity benefit calculations to support project selection and contract approvals, but policy makers generally take a more conservative approach.

vii) Policy Proposal Case Results

Case results are presented with benefits quantified and compared against potential costs. The costs were estimated and levelized over 20 years for the offshore wind and storage projects. For SOO Green, annual contract costs are posited for a 25-year term, but only totaled for the 20-year study period from 2030-2049 for comparison to the other policy options. The policy proposals would be supported by procurements oriented around an indexed product, RECs in the case of offshore wind and SOO Green and energy storage credits in the case of storage. Developers offer the costs of the policy proposals, plus return on investment as a "strike price." Ratepayers then cover the difference between the strike price and energy and capacity revenues from the wholesale market. The revenues reduce the subsidies that would be needed to support the implementation of the policy proposals.

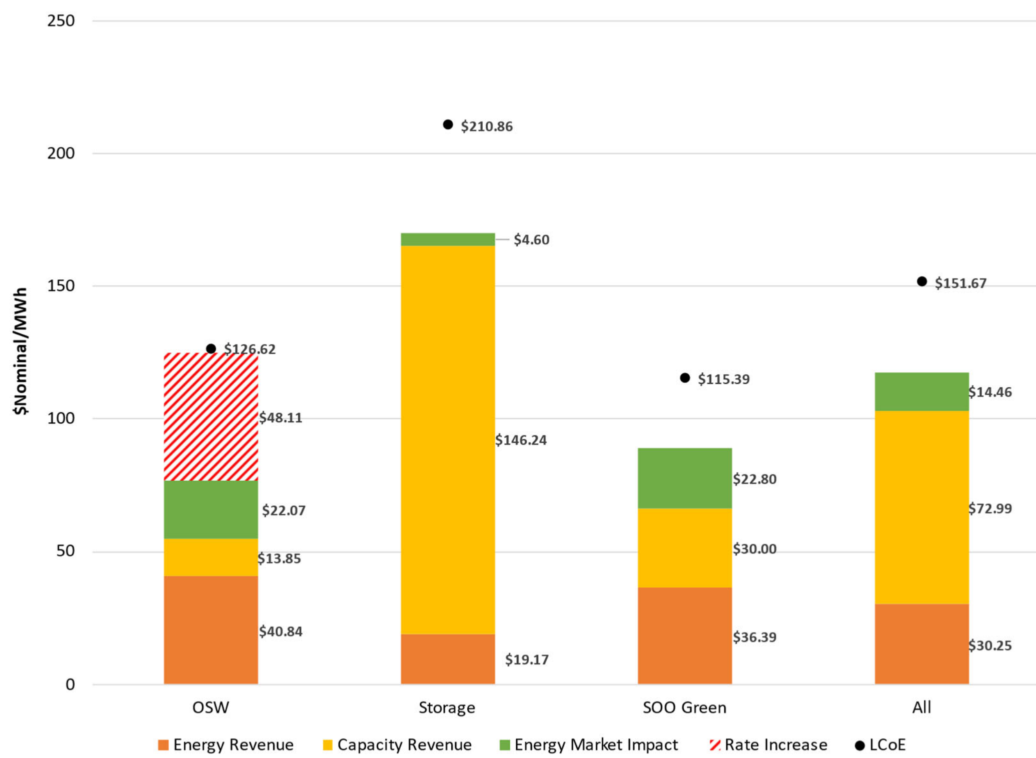
The LCOEs shown below indicate that the strike prices for the policy projects would range from about \$115/MWh to \$210/MWh. For SOO Green, the market revenue offset forecasts indicate that ratepayers will need to pay indexed RECs at an average of \$50/MWh over the 20-year modeled period. The rate increase of 0.25% posited under HB 2132 to fund the offshore wind pilot program is shown for comparison in the futures below; as posited it falls short of meeting the costs to make a pilot project commercially viable, but only price discovery through commercial negotiations can reveal the actual costs of the project. The wholesale energy cost reduction for electric demand in Illinois, which is calculated as the product sum of hourly energy prices multiplied by hourly demand, represents an indirect benefit of the project. Wholesale energy cost reduction is calculated for both ComEd and MISO LRZ4 in all policy cases. The reduction in wholesale energy costs caused by adding the SOO Green is \$22.80/MWh. Figure 8-17 summarizes the revenue offsets, wholesale energy cost reduction (energy market impact), and LCOE in nominal dollars.

[705] Order Approving Contracts for the Purchase of Tier 4 Renewable Energy Certificates, New York Public Service Commission Case 15-E-0302, issued April 14, 2022. See page 131: "The Commission does not agree with CPNY and HQUS that the wholesale market price suppression caused by these projects would be so large, and so permanent, that signing contracts with a strike price of up to around \$94 per MWh would actually save ratepayers money."

[706] The latest Board orders approving Offshore Wind Solicitation 3 are here: https://www.nj.gov/bpu/agenda/2024calendar/approved/20240124.html

[707] Order Granting Offshore Wind Renewable Energy Credits, Maryland Public Service Commission Case 9666, issued December 17, 2021.

Figure 8-17: Summary Projections, 2030-2049 (Nominal $)



The costs of these policy options will all represent an increase relative to current costs of power for Illinois ratepayers who will ultimately pay for the subsidies needed to support the policy proposals. Per EIA data, Illinois ratepayers paid about 10 cents per kWh, or $100/MWh of electricity, which includes charges for transmissions and distribution. Energy-only providers billed about 6 cents per kWh, or $60/MWh.[708] As shown in Figure 8-18, the levelized cost of electricity under each initiative exceeds the energy and capacity revenue and market impact offsets, so the proposals would contribute to increasing electricity costs in Illinois if implemented. The net rate impact of the proposals is the shortfall between the LCOE and the stacked bars. Illinois ratepayers will have to directly pay the shortfall between the strike price and revenue offsets, but that index REC cost will be indirectly reduced via wholesale price reductions in the Energy Market Impact.

[708] See EIA form 861.

Table 8-9 summarizes energy revenues, capacity revenues, and energy market impact by individual case. Table 8-11 summarizes CO_2, SO_2, NO_x and PM2.5 emissions reductions by case.

Table 8-9: Summary Projections, 2030-2049 Contract Period

Case	Costs	Energy Revenue	Capacity Revenue	Net Market Revenues	Energy Market Impact	Total	Energy Output
		$1,000 Nominal					GWh
OSW	$1,730,410	$558,104	$189,265	-$983,041	$301,629	-$681,412	13,666
Storage	$33,916,273	$3,082,900	$23,522,586	-$7,310,787	$739,111	-$6,571,676	160,849
SOO Green	$29,643,047	$9,348,275	$7,707,964	-$12,586,808	$5,858,042	-$6,728,767	256,891
All	$65,289,730	$13,023,447	$31,419,815	-$20,846,468	$6,224,719	-$14,621,749	430,469

Table 8-10: Emissions Impact Summary, 2030-2049 Contract Period

Case	*CO2*	*SO2*	*NOx*	*PM2.5*
	(Tons)			
OSW	7,488,714	-137	-129	21
Storage	27,309,080	8,223	15,528	701
SOO Green	152,660,227	7,722	6,172	975
All	187,073,709	18,367	20,872	1,725
Case	*CO2*	*SO2*	*NOx*	*PM2.5*
	(tons/MWh)	(lbs/MWh)		
OSW	0.55	-0.02	-0.02	0.00
Storage	0.17	0.10	0.19	0.01
SOO Green	0.59	0.06	0.05	0.01
All	0.43	0.09	0.10	0.01

The offshore wind resource, which is targeted to represent about 700 GWh annually per HB 2132, would represent about 0.5% of Illinois load when it enters service in 2030. The SOO Green project, which the model estimates would deliver about 12,800 GWh annually, would represent about 8.8% of Illinois load.[709] Energy storage systems would not represent incremental energy supply but help mitigate the system peak and balance demand and renewable energy. Compared to approximately 30 GW projected system peak projected in 2030, storage systems would meet about 25% of the peak.

The environmental benefits associated with the policy proposals stem from the additional renewable energy generation that the proposals would make possible. These benefits primarily involve avoiding the pollutants that would have been emitted from electricity generated by the combustion of fossil fuels in the absence of additional renewable generation made possible by the policy proposals. Emissions from the combustion of fossil

[709] Total load, as forecasted by the RTOs as sourced in the inputs section, is about 144.5 GWh.

fuels—specifically, particulate matter ($PM_{2.5}$),[710] sulfur dioxide (SO2) and nitrogen oxides (NOx)—are linked to a wide range of adverse health effects. These pollutant emissions can also damage the surfaces of agricultural crops adversely affecting growth rates and yields. Carbon dioxide (CO2), emitted by the combustion of fossil fuels, contributes to climate change. CO_2 also indirectly impacts public health concerns through reduced agricultural production, increased waterborne and pest-related diseases, increased storm severity, and ocean acidification.[711]

viii) Emissions Benefits

Emissions that are displaced by renewable generation can be determined with reasonable specificity, however, assigning monetary values to these emissions benefits is subject to significant uncertainty. Considering this uncertainty, in this report, the monetary benefits of the emissions displaced by the additional wind and solar generation that would result from the implementation of the policy proposals are reported as ranges.

Several studies[712,713,714] developed estimates for the marginal costs from electricity generation emissions. The ranges of costs in dollars per ton emitted are based on the monetary values reported in these studies converted to 2022 dollars:[715] SO_2 $7,900 - $35,000; NO_x $2,200 - $16,700; PM2.5 $12,900 - $120,700. The differences among the studies' cost estimates highlight the considerable uncertainties associated with the estimation of monetary values for emission costs. These estimations are dependent on a varying range of assumptions and inputs between studies.

Estimates of the avoided costs from displaced CO_2 are based on the social cost of carbon. The U.S. Environmental Protection Agency (EPA) considers the social cost of carbon to include the costs associated with CO_2 emissions that can be quantified. Each ton of CO_2 emitted results in both local and global impacts. While CO_2 emissions have global impacts, the EPA's quantification of costs is focused on the costs that affect individuals and accrue to entities in the U.S. The social cost of carbon is typically presented in terms of dollars per ton of CO_2 which measures the estimated future costs from carbon emissions in terms of present value using a discount rate. Since 2008 the estimated values for the social cost of carbon have

710 PM emissions are generally reported as either PM10, particulates that have diameters of 10 micrometers or less, or PM2.5, particulates of 2.5 micrometers or less.

711 U.S. Environmental Protection Agency, Air Pollution: Current and Future Challenges, www.epa.gov/clean-air-act- overview/air-pollution-current-and-future-challenges, updated October 23, 2023, accessed November 11, 2023.

712 Jaramillo, P. and Muller, N., "Air pollution emissions and damages from energy production in the U.S.: 2002-2011, Energy Policy 90 (2016) pp.202-211.

713 Goodkind, A.L. et al, "Fine-scale damage estimates of particulate matter air pollution reveal opportunities for location-specific mitigation of emissions," PNAS, April 30, 2019, vol. 116, no. 18, 8775-8780, www.pnas.org/cgi/doi/10.1073/pnas.1816102116.

714 Holland, S.P.; Mansur, E.T.; Muller, N.; Yates, A.J.; Decompositions and Policy Consequences of an Extraordinary Decline in Air Pollution from Electricity Generation, NBER Working Paper 25339, December 2018.

715 Prices escalated using St. Louis Reserve Bank Price Indexes for Domestic Product. Release Tables, Table 1.1.4 Annual , https://fred.stlouisfed.org

evolved based on growing scientific data that improved the understanding of the impacts of carbon emissions.

The Agency took into consideration a range of values for the social cost of carbon used to determine the benefits of displaced CO2 emissions. The lower end of the range reflects the domestic social cost of carbon (in 2020 dollars escalated to 2022 dollars) of $15.50/ton determined using a 5% discount rate.[716,717] This value for the social cost of carbon is based on estimates and calculations by the Interagency Working Group ("IWG") developed in 2016. The U.S. EPA's most recent social cost of carbon estimate (November 2023) uses a 2.5 percent discount rate to arrive at a value of $120/metric ton for 2020. Following the EPA's estimate of the real annual rate of increase of 1.55 percent for this cost, converting the value to 2022 real dollars[718] and converting to tons gives an equivalent social cost of carbon of $152/ton. This is the value that the Agency is using as the upper end of the range of social cost of carbon values for the calculation of displaced CO_2 emissions benefits. Older sources make up the lower-end values for social cost of carbon, and the IPA notes that the damage cost estimates have increased in more recent studies.

The IPA estimated the monetized benefits associated with policy proposals based on the estimated emissions avoid as calculated by the Aurora modeling and the costs presented in the previous table. These benefits are shown in ranges below.

Table 8-11: 20-Year Monetized Benefits Associated with Policy Proposals (2030-2049, Expressed in 2022 Real Dollars)

Case	CO_2	SO_2	NO_x	$PM_{2.5}$
OSW	$116 million - $1.14 billion	-$ 1 - -$5 million	$0 - -$2 million	$0 - $3 million
ESS	$423 million - $4.15 billion	$65 - $288 million	$34 - $259 million	$9 - $85 million
HVDC	$2.37 - $23.2 billion	$61 - $270 million	$14 - $103 million	$13 - $118 million
All	$2.9 - $28.44 billion	$145 - $642 million	$46 - $329 million	$22 - $208 million

The renewable policy projects are likely to continue operations after the 20-year period examined. Energy storage technologies, particularly batteries, may require significant ongoing investment to counter the degradation of storage capability. Once the assumed 20-year contract expires, Illinois would no longer hold title to environmental attributes from the policy projects. The modeling team conservatively did not count benefits that may accrue after the contracts contemplated in the policy proposals expire.

[716] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, February 2021, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide, Interim Estimates under Executive Order 13990.

[717] For context the $16.50/MWH Social Cost of Carbon used for the development of the Zero Emission Standard Procurement Plan translates to $31.37/ton based on a CO2 emissions factor of 1,052 lbs./MWh.

[718] Real dollars, also known as constant dollars, are adjusted to a base year (in this case, 2022) to control for inflation's effect on purchasing power.

In the draft study, one fossil unit was mis-identified as being located in Illinois. For this final study, that classification has been corrected, but as a result the emissions profile for the base case and the policy cases has changed. Specifically, the criteria pollutant emissions are only calculated for plants located in Illinois, since those pollutants have effects on a local level, while CO_2 emissions from the entire region are included because the impacts of CO_2 emissions are felt across geographies. In the offshore wind case, the incremental additional generation capacity offered by the offshore installation replaces out-of-state fossil-based baseload generation, but also results in an increased use of in-state fossil-based "peaker" plants. Peaker plants can be ramped up or down quickly to respond to changes in available baseload intermittent generation, like wind, providing short-term generation to meet any gaps when demand is high but there is no wind generation. Existing peaker plants often emit more criteria pollution than baseload natural gas plants.

Modeling changes were made to correctly retire gas-fired power plants that were not correctly flagged to convert to Zero Emissions Facilities. Retirement of several nuclear facilities outside of PJM was also corrected to match age-out input assumptions. These changes resulted in reduced baseload power available and utilized within Illinois to balance the intermittency of offshore wind in the corrected modeling. This results in a small increase in criteria pollutant emissions in the OSW case due to the increased utilization of in-state peaker plants, with mostly out-of-state baseload fossil generation being reduced. Since the emissions impact calculation does not consider out-of-state criteria pollutant emissions, that reduction does not offset the increased utilization of in-state peaker plants.

(1) Offshore Wind in Lake Michigan

Offshore Wind receives a comparable energy revenue (in unit terms) to SOO Green. Unit capacity revenue is relatively lower than other policy options due to the lower Unforced Capacity (UCAP) contribution, which is the MW value of the resource as cleared in the capacity market, compared to Installed Capacity (ICAP), which generally reflects the nameplate value.[719] Unit energy market impact scales similarly to other policy options.

Capacity market benefits for offshore wind are limited. PJM has identified declining UCAP expectations for renewable resources as development becomes more saturated.[720] PJM's ELCC calculations cannot be directly reproduced, but Aurora has some functionality to capture renewable resources' declining contributions to meeting peak demand. Offshore wind averaged a 22.5% UCAP factor (as a percentage of ICAP) during the procurement period (2030-2049), which compares well with GE ELCC results (29% in 2030, 20% in 2040).

Offshore wind is an intermittent resource and has stronger output in the winter. The winter output profile does track load fairly well. The summer output profile does complement solar

[719] See PJM Glossary https://www.pjm.com/Glossary

[720] December 2022 Effective Load Carrying Capability Report, PJM Interconnection, January 6, 2023. elcc-report-december-2022.ashx (pjm.com)

output as generation is lowest during the middle of the day but does not help to mitigate the loss of solar production with a strong evening ramp. Under the current RTO load forecast, Illinois (and the RTOs at large) are still summer peaking, but if electrification of building heating grows then the seasonality of offshore wind will better match the seasonality of load.

PJM's February 2024 ELCC stakeholder education materials reveal that oceanic offshore wind demonstrates an average deliverability of 27% during summer and 92% during winter, covering daytime, morning, and evening peaks.[721] This finding suggests potential benefits for Illinois, as the offshore wind complements solar output during the summer season and evening ramp. This finding supports an assertion from Union of Concerned Scientists, Environmental Defense Fund, and Sierra Club Illinois in comments on the draft Policy Study that the seasonal capacity contribution of offshore wind could be substantially higher.[722] Based on PJM's July 2023 material, offshore wind could have a winter accreditation value of 68%, which is four times greater than its projected summer values of 17%.[723] Notably though, the cohort of units included in PJM's analysis likely does not include any pilot projects in the Great Lakes and is representative of ocean-sited projects with higher overall capacity factors.

PJM has observed that winter risks predominate across all risk metrics, accounting for 54.8% for LOLE and 70.3% for Loss-of-Load Hours (LOLH), with corresponding summer risks at 45.2% and 29.7% respectively. Moreover, Expected Unserved Energy (EUE) exhibits 87.2% winter risk and 12.8% summer risk.[724] Previously, PJM indicated that roughly 64% of EUE occurred in winter, with 36% in summer, while about 65% of LOLE happened in summer, with the remaining 35% in winter.[725] These shifts in seasonal risk distribution are attributed to changes in the resource mix and the 2024 load forecast.

PJM proposed adopting the "marginal" ELCC approach, accrediting resources based on their marginal contribution to system resource adequacy within the target resource mix, rather than the "adjusted class average." FERC approved this new methodology on January 30th, 2024, under Docket No. ER24-99. At the time of the IPA study, PJM has not yet released a long-term forecast for ELCC class ratings.

[721] PJM ELCC Education, page 14, February 16 & 21 https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20240221-special/elcc-education.ashx

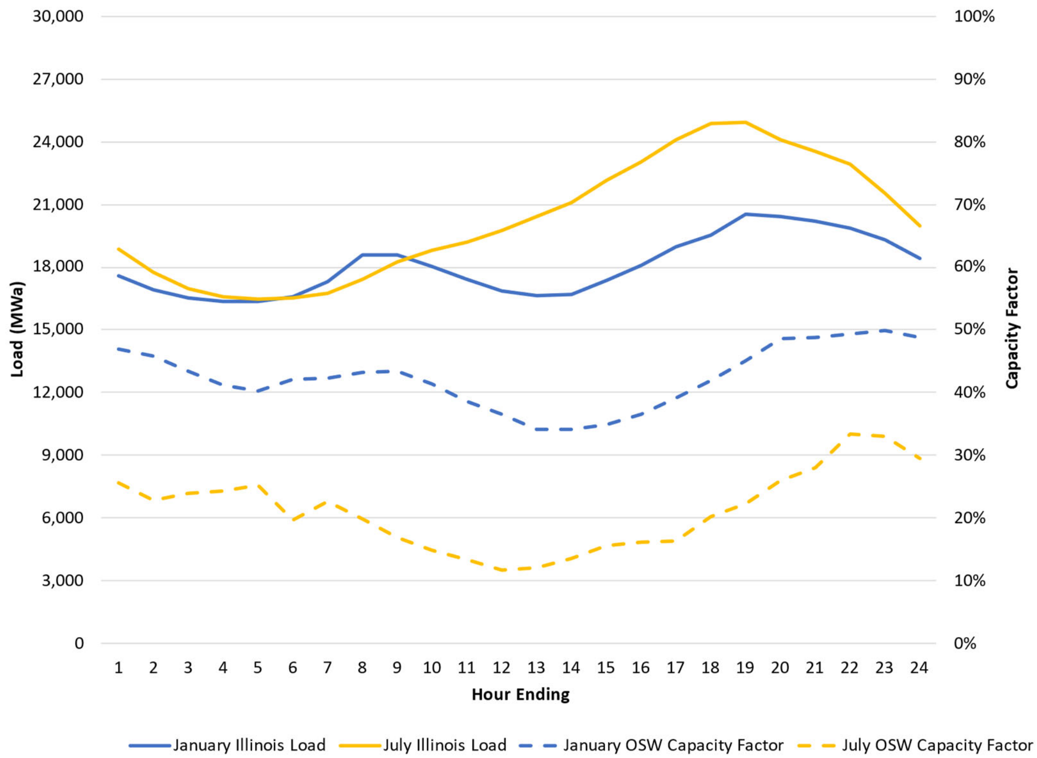
[722] Union of Concerned Scientists/Environmental Defense Fund/Sierra Club, February 12, 2024. See page 1. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240213-ucs-edf-sierra-club.pdf

[723] PJM Update on Reliability Risk Modeling Presentation, July 17, 2023. See page 8. https://pjm.com/-/media/committees-groups/cifp-ra/2023/20230717/20230717-item-03---reliability-risk-modeling---july-update-v2-copy.ashx#Page=8

[724] PJM ELCC Education, February 16 & 21, 2024. See page 21,38https://www.pjm.com/-/media/committees-groups/committees/pc/2024/20240221-special/elcc-education.ashx

[725] https://elibrary.ferc.gov/eLibrary/filelist?accession_number=20240130-3113&optimized=false at pages 113-114.

Figure 8-18: Load and Offshore Wind Average Profiles[726]



The introduction of the Offshore Wind pilot project had a small impact on the amount of ZEF resources dispatched, on the order of 1% decrease. ZEF output is clustered around peak hours rather than spread across the year.

(2) Energy Storage Systems Development

For energy storage systems development, energy revenue represents the revenue net the cost of charging the storage with grid power. That energy revenue effectively represents the difference between high-priced hours and low-priced hours in a given day, further dampened by efficiency losses. Therefore, energy storage systems receive less energy revenue over the 20-year period relative to generating resources on a $/MWh basis. Energy margins are also somewhat narrowed with the introduction of large quantities of storage, as storage charging increases prices and discharge reduces them. This dynamic is captured in the energy market impact. Energy storage systems' unit revenues and costs are calculated based on the discharge MWh of the facilities.

Capacity market benefits make up the lion's share of benefits for the energy storage systems proposal. Per the duration assumptions chosen, the 7,500 MW energy systems storage portfolio modeled had a weighted average UCAP factor of 82.6%. The energy storage systems ELCC values compare to 94% and 65% in GE's ELCC modeling for 2030 and 2040, but notably

[726] Load from 2050 averaged.

GE's ELCC values were modeled based on an isolated Illinois system. The renewable resource build assumed was limited to planned capacity in the GE MARS run, but storage resources may also have the opportunity to charge from surplus power if Illinois is receiving imports. PJM's ELCC Class Ratings for the 2025/2026 BRA provide 59% and 78% class ratings for 4-hour and 10-hour storage, respectively.[727] However no long-term forecast of Marginal ELCC given expected changes to PJM's capacity mix is presently available. With additional renewable power development, 4-hour storage ELCC may improve, as it did in PJM's previous ELCC reports.[728]

The introduction of storage resources had a significant impact on the dispatch of ZEFs. Storage reduced the output of ZEFs by 63%. The introduction of storage resources also effectively "idled" approximately 2,100 MW of ZEF capacity that was included in the base case. The idled units had zero output in the second half of the study period (2040-2049) in the Storage case.

Storage is active in peak shaving and renewable balancing in the production cost modeling. During the summer storage helps to mitigate the evening peak as solar generation ramps down. During the winter, some discharging is done during the morning ramp to help mitigate the morning peak, charging occurs midday to store solar output, and then batteries discharge to mitigate the evening peak.

Ancillary services were not quantified in the Aurora modeling but represent additional revenue opportunities for energy storage systems. PJM and MISO may need to procure additional quantities of traditional reserve products (reserves, regulation) in order to mitigate renewable output forecast error as more wind and solar come online.

In comments on the draft Policy Study, the Energy Storage Associations requested that IPA quantify the reduction in ancillary service cost due to storage.[729] Those comments cited the all-in value of PJM ancillary services markets,[730] but several of these services are not market-based, but cost-based where generators (or PJM, in the case of control room services) are assessed on a cost of service basis. Therefore, storage would have a limited impact on these costs, which are negotiated between PJM and individual generators. Ancillary services costs in PJM are shown below:

[727] https://pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx

[728] PJM December 2022 Effective Load Carrying Capability (ELCC) Report, see Figure 4. 4-hour storage ELCC increased from 77% in 2025 to 100% by 2031. https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-report-december-2022.ashx

[729] Energy Storage Associations Comments to the IPA Draft Policy Study, page 11.

[730] Monitoring Analytics, 2023 State of the Market Report for PJM, January Through June, See Table 10-4. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2023/2023q2-som-pjm-sec10.pdf

Table 8-12: Services Cost per MWH of Load 2022[731]

Regulation	Scheduling, Dispatch, & System Control	Reactive	Synchronized Reserve	Total
$0.38	$0.46	$0.50	$0.12	$1.46

The Scheduling, Dispatch, and System cost category is largely made up of PJM costs and black start services, which storage is unlikely to compete for. PJM's market monitor defines black start as "… the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid (automatic load rejection or ALR)." The market monitor notes that "PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of cost of service rates defined in the tariff." In 2022, ComEd was assessed about $9 million in black start charges.[732] PJM's Market Monitor notes that "Reactive capability charges are based on FERC approved filings for individual unit revenue requirements that are typically black box settlements. Reactive service charges are paid to units that operate in real time outside of their normal range at the direction of PJM for the purpose of providing reactive service." Reactive capability charges are represented about $384 million out of $385.5 million total reactive power charges in 2022.[733] However, this market is spread across 800 resources within PJM. Given that the vast majority of the Regulation is a market-based product, but the quantities sold are so small (500-800 MW) that the CONE study did not recommend that units be assumed to capture new revenue.[734] Storage may also provide reserves, which are a market-based product, but the average primary reserve MW requirement was about 3,700 MW in 2022.[735] Some of the reserve market is also cleared locationally, so ComEd zone resources cannot capture some portion of revenues or defer costs. The value of *market-based* ancillary services products to the ComEd zone, assuming that costs are assigned by load share similarly to the Energy Storage Associations' comments, is closer to $40 million a year, and increased storage capability will have to compete with other resources in PJM's markets.

The size of Ameren's ancillary services obligations is also overstated in the comments of the Energy Storage Associations. It appears that prices for regulation and reserves were added together, but these services are not assessed on the same quantities and therefore are not

[731] Monitoring Analytics, 2022 State of the Market Report for PJM, See Table 10-6. https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec10.pdf

[732] Monitoring Analytics, 2022 State of the Market Report for PJM, see page 610 and Table 10-71.

[733] *Id*, see page 545, Tables 10-75 and 10-78.

[734] "Regarding ancillary services, we determined that regulation revenues should not be included in the calculation because the market is too small at only 500-800 MW (some of which is already absorbed by BESS plants providing the premium RegD product)." The Brattle Group, Sargent & Lundy, PJM CONE 2026.2027 Report, page 52. PJM CONE 2026/2027 Report.

[735] Monitoring Analytics, 2022 State of the Market Report for PJM, See Table 10-9.

additive. MISO's 2022 State of the Market Report notes that the "all-in" price of electricity, where all products (energy, capacity, ancillary services, and uplift) are spread across demand, was only $0.16/MWh for ancillary services.[736] The true cost of ancillary services, if estimated by load share, for Ameren customers would be about $5-6 million. The current markets for ancillary services are small, though need for ancillary products may grow in the future.

(3) SOO Green HVDC Transmission Line

SOO Green has a similar unit energy market revenue to the offshore wind development. The energy market impact is higher than for other policy options due to the stronger "around the clock" profile of the clean energy imports. In addition, headroom on the HVDC transmission line may be used for economic imports of system energy.

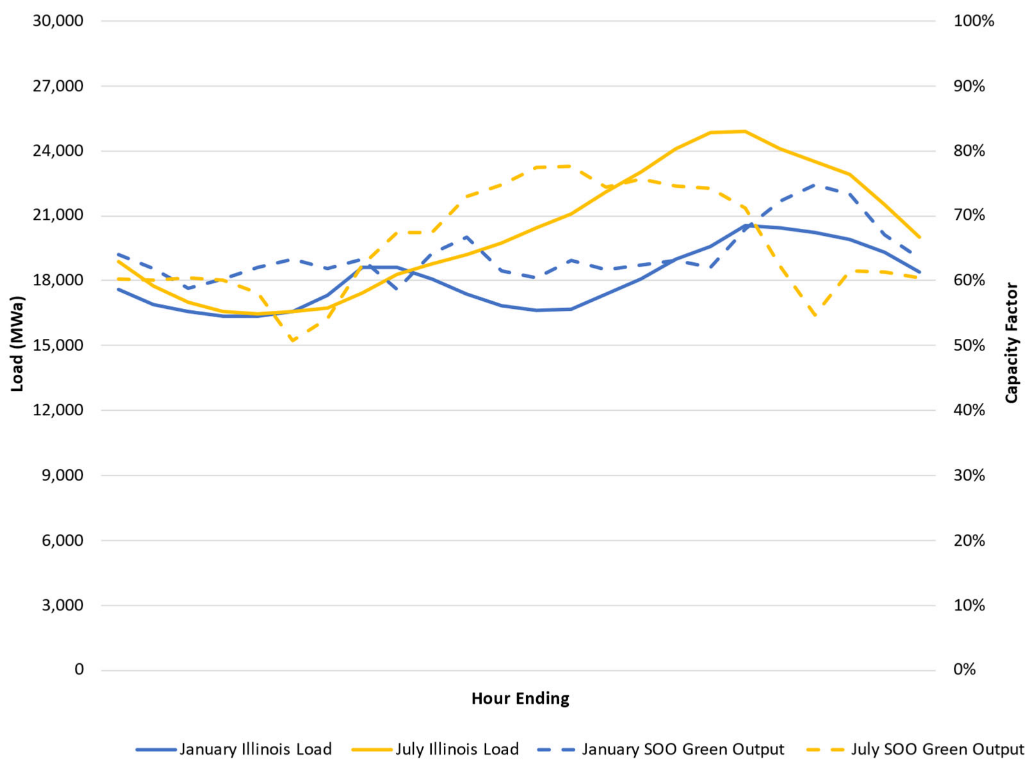
Capacity benefits of the SOO Green line were estimated based on the average clean energy flows over the HVDC transmission line during peak hours of the observed system peak for PJM. Based on this calculation, a 87.3% UCAP factor was estimated for the SOO Green HVDC transmission project. Any incremental flows from "system" energy that is not secured by SOO Green as clean energy supplied to Illinois via contract is not assumed to provide capacity value. The renewable supply portfolio contracted for transport via SOO Green is not assumed to provide any residual capacity to MISO; these contracted resources would likely be required to "de-list" from the MISO market in order to become qualified as external resources in the PJM capacity market. This UCAP estimate is similar to GE's MARS ELCC results of 96% in 2030 and 92% in 2040. In comments on the draft Policy Study, Invenergy Transmission noted that if the combined class ratings of the clean energy portfolio were accredited per the most recently posted ELCC ratings PJM has posted, the total accredited capacity would be 1,589 MW, or 76%.[737] The modeling team notes that SOO Green would not be placed into service in time for the 2025/2026 BRA, and that PJM has not yet released a long-term load forecast under the new Marginal ELCC methodology.

SOO Green has a relatively high capacity factor (about 70% over the study period) due to the "overbuild" of renewable supply needed to energize the HVDC line, as well as the storage resource that helps to bank surplus energy for later delivery over the line. The influence of solar on high delivery volumes can be seen in the summer delivery profile. The facility essentially performs as a baseload or efficient intermediate level generator for the ComEd zone.

[736] Potomac Economics, 2022 State of the Market for the MISO Electricity Markets, June 15, 2023. See page 4. 2022 STATE OF THE MARKET REPORT (potomaceconomics.com)

[737] Invenergy Transmission Response to IPA Draft Policy Study, page 9. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240213-invenergy-transmission.pdf

Figure 8-19: Illinois Load and SOO Green Output Profiles, 2050



The introduction of SOO Green had a significant impact on the dispatch of ZEFs. SOO Green reduced the output of ZEFs by 29%. The introduction of SOO Green also effectively "idled" approximately 700 MW of ZEF capacity that was included in the base case.

In order to capture the 25-year contract term identified in P.A. 103-0580, costs, revenue offsets, and energy market impacts were extrapolated to cover the remaining 5-year period (2050-2054). The strike price is in nominal level terms, consistent with the CPNY contract, so no growth was applied. The energy revenue was extrapolated based on the average growth rate over 2045-2049. Capacity revenue was expected to grow at the rate of CONE escalation (3.5%). Energy market impacts were conservatively extrapolated in the same manner as energy revenue but given that market impacts are greater after retirement of the fossil fleet, the additional energy market impacts estimated are substantial. Clean flows over the line were assumed to be the five-year average across 2045-2049.

Table 8-13: SOO Green Summary Projections, 2030-2054 Contract Period

Case	Costs	Energy Revenue	Capacity Revenue	Net Market Revenues	Energy Market Impact	Total	Energy Output
		$1,000 Nominal					GWh
($1,000 Nominal)	$37,025,252	$12,800,308	$11,105,160	-$13,119,784	$9,268,046	-$3,851,737	320,866
($1,000 2022) - Annualized	$907,502	$301,753	$250,918	-$354,831	$206,814	-$148,017	12,835

(4) All Policies Adopted

The unit benefits of the All Policies case are driven by the energy storage systems and SOO Green impacts, given the relatively small size of the offshore wind project in relation to these projects. The energy storage systems and SOO Green projects deliver similar amounts of energy, so the relative size of each benefit category reflects this balance.

The UCAP contribution for the combined portfolio of offshore wind, energy storage systems, and the SOO Green project totals 8,070 MW, or 82.3% of nameplate offshore wind, Illinois energy storage systems, and SOO Green HVDC transmission capacity. The calculated UCAP contribution for the SOO Green project remains at 87.3% in the All Policies case.

The introduction of all policy resources had a significant impact on the dispatch of ZEFs. ZEF output was reduced by 76%. The introduction of all policy resources also effectively "idled" approximately 2,200 MW of ZEF capacity that was included in the Base Case.

(5) Distributed Scale Paired Storage Sensitivity

The distributed scale paired storage sensitivity was not run through production cost modeling. However, to provide a sense of expected costs, revenues, and benefits, the modeling team scaled results from the Storage case to provide a first-cut estimate. The scaled results from the Storage case, combined with the Residential and Commercial Storage cost data (briefly discussed above), are summarized below in Table 8-15.

Table 8-14: Distributed Project Annualized ($2022) Summary

Description	Costs	Energy Revenue	Capacity Revenue	Net Market Revenues	Energy Market Impact	Total
Storage ($1,000 2022)	$197,891	$15,141	$100,567	-$82,182	$4,057	-$78,125
Storage ($2022/MWh)	$8.00	$0.61	$4.06	-$3.32	$0.16	-$3.16

ix) Estimated Bill Impacts

In response to a recommendation on the draft Policy Study made by Vistra,[738] the modeling team conducted an additional analysis to estimate the bill impact for the average residential Ameren or ComEd customer of the policies studied. The bill impacts were estimated by unitizing net costs (costs net market revenues) across retail load, as found in Appendix B of the filed 2024 Long-Term Renewable Resources Procurement Plan.[739] The unitized cost is then multiplied by the current average annual residential usage of Ameren and ComEd customers, which are 11,355 kWh and 7,302 kWh, respectively.[740] The "Net Market Revenues" bill impacts represent the cost to the consumer to support the given policy .

Table 8-15: Average Monthly Residential Bill Impact (2030-2049)

Bill Impact (2030 – 2049)	Offshore Wind	Energy Storage	HVDC
Ameren (Real 2022 dollars)	$0.25	$1.89	$3.42
Ameren (Nominal dollars)	$0.39	$2.88	$4.99
ComEd (Real 2022 dollars)	$0.16	$1.21	$2.20
ComEd (Nominal dollars)	$0.25	$1.85	$3.21

x) Conclusions

Aurora production cost modeling results show that market energy and capacity revenues fall short of the costs of the policy proposals. Thus, each of these policy projects individually, as well as if all three were to be operated together, would result in higher electricity costs for Illinois. The net difference between the annualized costs and offsets, and energy market benefit would result in net costs which would be reflected in higher electricity rates in the state. Under the costs and revenues contemplated, SOO Green would result in net annual costs of $252 million while the storage proposal would result in net annual costs of $216 million. The offshore wind system would result in net annual costs of $23 million. In terms of impacts on the Illinois power market, the state's clean energy policies, and electricity costs, the storage initiative offers the greatest benefits, slightly greater than SOO Green, but also has the highest costs. Offshore wind has the lowest net annual cost, which is reasonable given the relatively small scale of the project size. Of the policies studied, only the offshore wind proposal includes a cap on the subsidy value; this analysis shows that the proposed

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738 Vistra Corp.'s Comments on Illinois Power Agency's Draft 2024 Policy Study, see page 5. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/20240213-vistra-corp.pdf

739 See sheet "Collections and ACP". Retail load is assumed to stay constant following the last reported year. https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/appendix-b-20-oct-2023-11am.xlsx

740 Illinois Commerce Commission, Illinois Electric Utilities Comparison of Electric Sales Statistics For Calendar Years 2022 and 2021, page 8. https://icc.illinois.gov/api/web-management/documents/downloads/public/en/22-21 Comparison of Electric Sales Statistics-.pdf.

subsidy value will not quite fully support a commercialized pilot project at the level of costs and revenues projected.

Table 8-16: Project Annualized ($1,000 2022) Summary

Case	Costs	Energy Revenue	Capacity Revenue	Net Market Revenues	Net Market Revenues Accounting for RPS Increase[741]	Energy Market Impact	Total
OSW	$54,923	$17,618	$5,739	-$31,565	-$10,598	$8,875	-$22,690
Storage	$1,050,160	$96,276	$714,742	-$239,142		$22,616	-$216,525
SOO Green	$960,437	$295,990	$233,739	-$430,708		$178,305	-$252,403
All	$2,065,520	$411,169	$954,221	-$700,130		$188,490	-$511,640

While reflecting increased costs of electricity, each policy initiative would offer significant environmental benefits in terms of reductions in the emissions of CO2, than would occur if these initiatives were not implemented. When considering electric system wide operations (including other states in PJM and MISO), SOO Green has the greatest impact with estimated 20-year CO2 of 153 million tons followed by the storage reductions of 27 million tons and the offshore wind project with 7 million tons. In Illinois, SOO Green would reduce SO2 emissions by 8 thousand tons, NOx emissions by 6 thousand tons and PM2.5 emissions by one thousand tons. The storage initiative would reduce SO2 emissions by 8 thousand tons, NOx emissions by 15 thousand tons and PM2.5 emissions by 700 tons. The OSW project results in a small increase in in-state SO2 and NOx emissions of about 100 tons each. PM2.5 emissions are reduced by 21 tons.

The electricity cost impacts reflect the status of technology and markets based on currently available information and assumptions. Capital and operating costs may decline more rapidly than the Conservative case assumed in the ATB. The recent cost pressures resulting from inflation and the supply chain issues plaguing renewable power sources which have led to increased costs and many renewable project cancellations are likely to abate. Wholesale power market rules and federal policy may also shift the relative costs and benefits of the policy proposals. Interconnection costs, subject to changing Federal and ISO regulations and policies, also represent a source of uncertainty. Interest rates represent another source of uncertainty that affects financing costs. Storage costs may also be reduced by pairing the facilities with renewable generation to receive the ITC, though these projects may have reduced operational benefits due to restrictions on grid charging necessary to obtain the credit. Deeper decarbonization of other economic sectors would increase load and could put upward pressure on market prices.

[741] The $32-34 million collected annually between 2030 and 2049 by the increase in the RPS rate is $20.96 million in real 2022 dollars.

e) Evaluation of Economic Impacts Affecting Illinois

For evaluating economic impacts, the specific policy proposal responses that were evaluated included: an offshore wind project that would supply 700,000 RECs annually for 20 years, which the IPA assumed would have a capacity of 200 MW; in accord with SB 1587, to implement a procurement of energy storage credits that would support the cost effective deployment of Utility Scale ESS of at least 7,500 MW, and a policy requiring the agency to procure RECs related to a new high voltage direct current (HVDC) transmission line, which the IPA understands would be the SOO Green HVDC line. The IPA also evaluated the impacts associated with distributed storage, which since SB 1587 did not specify at target capacity for distributed storage the IPA assumed that a reasonable capacity to be evaluated would be 1,000 MW. Among the impacts to be evaluated are the impacts of the proposals on employment in Illinois and on the state's economy. The IPA used a general input-output model to evaluate and estimate the employment and economic impacts.

An input-output analysis is a type of applied economic analysis that tracks the interdependence among various producing and consuming industries in an economy; it measures the relationship between a given set of demands for final goods and services, and the inputs required to satisfy those demands. For the Policy Study the Impact Analysis for Planning (IMPLAN) model was used to analyze the economic impact of the four policy cases (SOO Green HVDC Transmission Link, Lake Michigan offshore wind, Utility ESS, and Distributed Storage under consideration. The full report is available as Appendix D.

i) Economic Impacts Modeling

The IMPLAN modeling system is widely used in many industries to evaluate the economic impacts of policies and investments. IMPLAN utilizes proprietary analytical software to conduct Input-Output analyses and develop a Social Accounting Matrix, which is a type of applied economic analysis that tracks the interdependence among various producing and consuming industries of an economy and the spending of households. It measures the relationship between a given set of demands for final goods and services and the inputs required to satisfy those demands.[742] The results from the IMPLAN model, as with any analysis of economic impacts that occurs prior to the actual implementation of the policies or investments, are dependent on estimated values used as inputs to the model. The values for these inputs cannot be known with certainty and could change significantly as the projects responding to the policy proposals move through the development, financing, and construction phases. IPA therefore presents the values for the economic and employment impacts of the policy proposals in this report as a guide for policy makers and stakeholders in Illinois.

[742] "IMPLAN Report Toolkit," IMPLAN Group LLC; August 30, 2023 (https://support.implan.com/hc/en-us/articles/360044985833-IMPLAN-Report-Toolkit)

To run IMPLAN, a set of input values covering the capital and operating costs associated with the policy being evaluated is required for the model to estimate the economic impacts of the policy proposal.[743] These input values do not include any spending associated with the policies that will occur outside the state of Illinois, as the economic benefits from this any out-of-state spending will not occur in Illinois. The input values are generally specified as monetary values and a corresponding IMPLAN industry code (the IMPLAN Sector) that specifies which parts of the economy are initially impacted by the policy. The IMPLAN model then tracks the initial economic impacts through a state or regional economy using its proprietary multipliers to estimate the total effect on the modeled economy resulting from the policy. The IMPLAN inputs used for each of the policy cases are discussed below. For each policy case, the inputs cover construction (otherwise known as Capital Expenditure or "CapEx") and 20 years of operation (otherwise known as Operating Expense or "OpEx").

The CapEx Inputs typically include items such as the installed cost of capital equipment including wind turbines, batteries, transformers, and other necessary electrical equipment. OpEx costs include operating, maintenance and repair costs. A detailed breakout of the inputs used for this analysis can be found in the full IMPLAN evaluation report which is attached as an appendix to this study. Since the projects that would be likely to respond to the policy proposals are still in the early formulation and planning stage of development, the IPA developed its inputs values for the IMPLAN model using the following public sources:

- The SOO Green HVDC Transmission Link, "Economic Impact of the SOO Green HVDC Link Transmission Project on the State of Illinois," Strategic Economic Research, LLC; February 2023.
- The Lake Michigan offshore wind Project, "Great Lakes Wind Energy Challenges and Opportunities Assessment," National Renewable Energy Laboratory and Renewable Energy Consulting Services, Inc.; March 2023. https://www.nrel.gov/doc/fy23osti/84605.pdf.
- The Utility Scale ESS, "NREL ATB, Utility-Scale Storage," National Renewable Energy Laboratory, June 2023. https://atb.nrel.gov/electricity/2023/utility-scale_battery_storage.
- The Distributed Storage scenario inputs were based on the Utility-Scale inputs but were modified to reflect higher CapEx and OpEx inputs due to the smaller scale and greater labor intensity of the distributed storage projects.

The SER study was commissioned by SOO Green to provide estimated economic benefits that the construction and operation of the Illinois portion of the HVDC line would bring to Illinois. The objective for this study was to provide decision makers, state agencies and other stakeholders in the state with SOO Green's estimates of the policy's economic benefits. The SER report defined the CapEx inputs through consultation with SOO Green, thereby reducing the uncertainties for the input values used in the Policy Study's analysis. The reduced uncertainty with the SER based input values mitigated the need for a range of economic

[743] The costs modeled in IMPLAN are the proposal's total in-state cost without any subsidies or project revenues subtracted.

impacts to be presented. The OpEx results used for the policy study analysis were derived from the Policy Study's CapEx results and the relationship between the CapEx and OpEx results in the SER analysis.

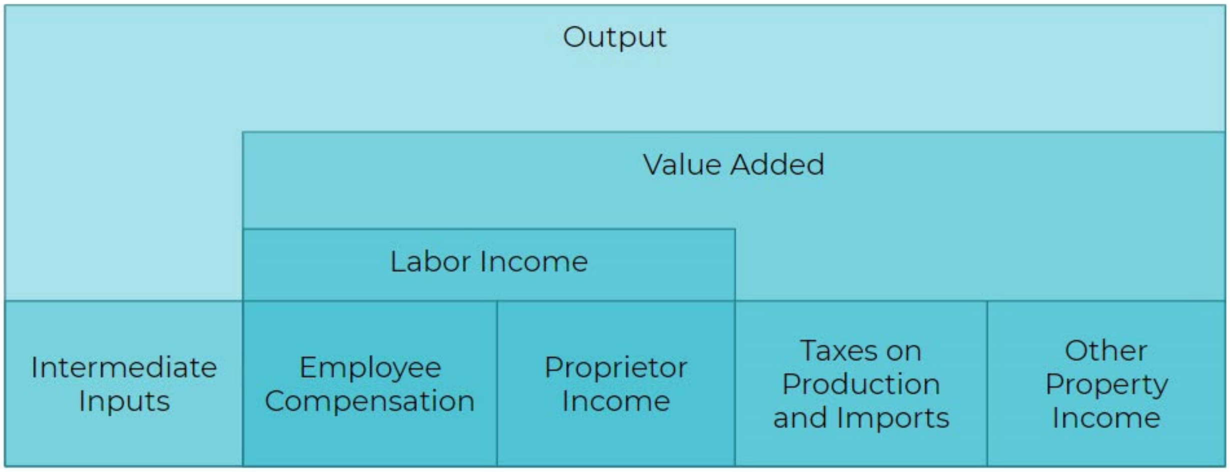
The offshore wind, Utility ESS and Distributed Storage analyses produced a range of employment and economic impacts values given the cost uncertainties associated with the offshore wind project and the major impact that building the batteries for the storage proposals in Illinois would have on the storage analysis results. The High CapEx/OpEx case for the offshore wind project was based on input values taken from the NREL Current Technology Scenario. The High Cap/OpEx cases for the storage analyses were based on assumptions relating to the batteries being built in Illinois, greatly magnifying the economic and employment impacts over the Low Cap Ex/OpEx storage cases that assumed the batteries would be built outside of the State.

ii) Economic Impact Evaluation Results

IMPLAN provides results in the form of employment, labor income, value added and output. The differences between labor compensation, value added and output are illustrated in Figure 8-20.

- Employment is the number of jobs associated with economic activity and is expressed as 2,080-hour FTE-years. For example, an employment impact of one is equal to a single person working 2,080 hours.
- Labor income is all forms of employment income, including employee compensation (wages and benefits) and proprietor income.
- Value added is the difference between an industry's or establishment's total output and the cost of its intermediate inputs; it is a measure of the contribution to GDP.
- Output is the value of industry production, including the cost of its intermediate inputs.

Figure 8-20: Differences Between Labor Income, Value Added and Output



For each of these four metrics, IMPLAN provides the direct effects, indirect effects, induced effects and total effects.

- The direct effects are the effects to a local industry or industries due to the activity or policy being analyzed.
- The indirect effects are the effects stemming from business-to-business purchases in the supply chain taking place in the region.
- The induced effects are effects in the region stemming from household spending of income, after removal of taxes, savings, and commuters.
- The total effects are the sum of the direct, indirect, and induced effects.

Output represents the total production value of economic activity and includes all components of production value. This metric includes the cost of intermediate inputs, which should be netted from the total production value to provide a more accurate measure of the impact on the target economy. Value Added, which represents the difference between Output and the cost of intermediate inputs, is considered to be the metric that most accurately reflects the economic impact.

All IMPLAN results were obtained for Illinois using the latest available 2022 data year and exported as real 2023 dollars. The breakdown of the direct, indirect, and induced effects can be found in the Appendix. The total employment and total value-added results for the seven IMPLAN analysis cases are presented in Table 8-17 and Table 8-19.

Table 8-17: Comparison of Total Employment

Case	Total Job Creation		
	FTE-years	FTE-years/MW	FTE-years/TWh
SOO Green CapEx[744]	1,990	0.948	7.492
SOO Green OpEx	1,480	0.705	5.571
Offshore Wind Low CapEx	484	2.418	35.378
Offshore Wind High CapEx	1,121	5.603	81.990
Offshore Wind Low OpEx	281	1.404	20.548
Offshore Wind High OpEx	772	3.861	56.493
Utility-Scale Energy Storage Low CapEx	16,473	2.196	100.877
Utility-Scale Energy Storage High CapEx	62,107	8.281	380.338
Utility-Scale Energy Storage Low OpEx	9,555	1.274	58.515
Utility-Scale Energy Storage High OpEx	31,766	4.235	194.534
Distributed Energy Storage Low CapEx	4,198	4.198	192.807
Distributed Energy Storage High CapEx	14,329	14.329	658.136
Distributed Energy Storage Low OpEx	2,191	2.191	100.608
Distributed Energy Storage High OpEx	7,127	7.127	327.345

[744] The IPA's IMPLAN results for the direct labor income differ from the results shown in the SER February 2023 report prepared for SOO Green since SER used a different methodological approach that included calculation of the direct labor impacts outside of the IMPLAN model while the IPA's analysis relied on the IMPLAN model without external calculations.

Table 8-18: Comparison of Total Value Added

Case	Value Added		
	$	$/MW	$/TWh
SOO Green CapEx	$237,744,695	$113,212	$895,056
SOO Green OpEx	$176,800,517	$84,190	$665,665
Offshore Wind Low CapEx	$61,144,172	$305,721	$4,473,504
Offshore Wind High CapEx	$153,688,671	$768,443	$11,244,358
Offshore Wind Low OpEx	$36,676,720	$183,384	$2,683,387
Offshore Wind High OpEx	$111,436,228	$557,181	$8,153,033
Utility-Scale Energy Storage Low CapEx	$1,969,419,166	$262,589	$12,060,567
Utility-Scale Energy Storage High CapEx	$8,836,463,187	$1,178,195	$54,113,801
Utility-Scale Energy Storage Low OpEx	$1,138,331,501	$151,778	$6,971,052
Utility-Scale Energy Storage High OpEx	$4,490,941,843	$598,792	$27,502,172
Distributed Energy Storage Low CapEx	$510,450,822	$510,451	$23,444,703
Distributed Energy Storage High CapEx	$2,036,437,850	$2,036,438	$93,532,382
Distributed Energy Storage Low OpEx	$259,859,576	$259,860	$11,935,196
Distributed Energy Storage High OpEx	$1,005,621,973	$1,005,622	$46,187,620

Table 8-19: Summary of IMPLAN Economic and Employment Impacts

Proposal	Employment (FTE-Yrs)	Employment (FTE-Yrs/MW)	Value Added (MM$)	Value Added (MM$/MW)
SOO Green	3,470	1.65	$414.5	$0.197
Offshore Wind	764 - 1,893	3.82 – 9.47	$97.8 - $265.1	$0.489 – $1.330
Utility Scale ESS	26,028 – 93,873	3.47 – 12.52	$3,107.7 – $13,327.4	$0.414 – $1.777
Distributed Storage	6,389 – 21,456	6.39 – 21.46	$770.4 – 3,042.0	$0.770 – $3.042

iii) Conclusion

The IMPLAN analyses show a range of economic impacts would be associated with the policy proposals. The total employment impacts in terms of FTE-years range from 764 for the low case of the Lake Michigan Offshore Wind project to 93,873 for the high case of the Utility ESS proposal, which assumes all of the battery cells will be manufactured in Illinois. In addition to the employment impacts, the economic impacts, as measured by the total value added, range from $97.8 million for the low case of the Lake Michigan Offshore Wind project to $13.3 billion for the Utility ESS high case. The energy storage cases have the largest impact in terms of value added and employment with the total employment for the Utility ESS and Distributed Storage cases taken together ranging from 32,417 FTE-years to 115,329 FTE-years and the total value added ranging from $3.9 billion to $16.3 billion. The larger magnitude of the economic and employment impacts associated with the high CapEx and high OpEx energy storage cases may offer support for policies designed to encourage battery manufacturers to locate new manufacturing and assembly facilities in Illinois.

The other policy proposals would have significantly less employment and total value added impacts, with the SOO Green HVDC Transmission Link having an employment impact of 3,470 FTE-years and total value added impact of $414.5 million, and the Lake Michigan Offshore Wind project having an employment impact of 764 to 1,893 FTE-years and total value added impact of $97.8 million to $265.1 million. However, when the employment and total value added impacts are considered on a united $/MW basis, the Lake Michigan Offshore Wind project provides employment and value added impacts comparable to the lower end of the range of Utility ESS impacts, 3.82 to 9.47 FTE-years/MW and $0.49 million to $1.33 million/MW for the Lake Michigan Offshore Wind project compared to 3.47 FTE-years/MW and $0.41 million/MW for the low case of the Utility ESS proposal.

While IMPLAN does not specifically address the way in which the employment and value added impacts would be distributed around the state, several observations can be drawn from the modeling results. The Utility ESS and Distributed Storage impacts are likely to be spread around the state but would be concentrated in MISO Zone 4 where most of the modeled ESS queue locations are located and in the high cases where the battery cell manufacturing facilities would be located. The employment and economic impacts for the SOO Green HVDC line would primarily impact the counties along the path of the line: Carroll, DeKalb, Kendall, Lee, and Ogle, as well as the location of the converter station and interconnection with the ComEd system near Plano. The employment and value added impacts of the Lake Michigan Offshore Wind project would likely be in the Chicago area, as it has been proposed as a staging area for the construction and operation of the project, although the construction of the turbines would probably occur outside of the state.

9) Recommendations

Section 1-129(f) of the Illinois Power Agency Act (enacted through Public Act 103-0580) states that "[t]he policy study shall include policy recommendations to the General Assembly." In the preceding chapters, the Agency has examined each of the policy proposals in detail including modeling of impacts, comparisons to similar policies in other states, and consideration of state-specific dynamics and issues.

Based on that examination, the Agency offers the following recommendations to the General Assembly for consideration. These move from general recommendations to more specific recommendations across the three bills posited for analysis.

a) General Recommendations

i) Account for Cost Volatility

The General Assembly should consider the results presented in this Policy Study as illustrative of the range of impacts that the proposed policies could have, and not as definitive values.

Rising interest rates, high inflation, and ongoing supply chain issues have all contributed to economic volatility over the past several years, and the energy industry has not been immune to that volatility. While these economic stresses may improve in coming years, they are not likely to be completely abated and should be considered when developing new energy policies for Illinois.

The modeling conducted for this Policy Study used the best available information present while the Study was conducted, though the information will change over time. For example, this Study used data on the installation costs for batteries published by NREL in 2023. When these costs are updated by NREL after this Study is completed, the modeling results contained in this Study would likewise require updates. Recent PJM load forecasts (released too recently for incorporation into this Study) show substantially greater expected load growth over the next 15 years than forecasts released one year prior. Benefits of the policies discussed herein generally grow in magnitude against the backdrop of growing load.

These types of changes are always a challenge in forecasting outcomes, but are highlighted here because of the high level of uncertainty observed in forecasting future costs.

The General Assembly should carefully consider a) guardrails to properly balance risks between developers and ratepayers and b) flexibility in contractual obligations.

Cost uncertainty offers back the challenge of how to address downstream cost changes. The policies analyzed would provide support to projects through funds collected by utilities from ratepayers and then paid to project developers. This support generally comes through competitive procurement processes requiring bidders to submit prices that those bidders believe will provide sufficient revenue to finance and develop a project.

But what if they're wrong? In a vertically integrated state, changes in supply, interconnection, land, labor, and other costs can be wrapped into a rate base, with cost recovery at levels reflecting actual costs. The developer is made whole even under changed conditions. Under a regime utilizing competitive procurements with hard-coded cost caps or fixed contract prices—with bids often received years before development commences—project development may only be viable if actual development costs are at or below original estimates.

As policies requiring this level of capital investment are considered, the General Assembly must consider the following: are there opportunities for contract adjustments? Are there options to allow contracts to be terminated, and subsequent provisions for additional procurements? What level of proof would be required under what process? Flexibility that reduces risks to project developers will need to be weighed against the impact of rising costs to ratepayers, but clarity on process is necessary not only to ensure a successful procurement event, but also to reduce unnecessary risk premiums in bids.

ii) Ensure Commitment to Equity and Labor Standards

The General Assembly should ensure that broad commitments to equity and labor standards extend across all policies.

Each policy studied involves a substantial outlay of Illinois ratepayer funds to support substantial capital investment in a new project or in multiple projects. These projects provide not only much-needed energy, but also provide economic opportunities for workers and companies in Illinois. As a condition of benefitting from this substantial public investment, any policy considered should meet cornerstone labor and equity requirements ensuring a skilled, diverse, equitable, and sufficiently compensated workforce.

A cornerstone of the Climate and Equitable Jobs Act ("CEJA") is its commitment to expand equity within Illinois' growing clean energy economy. The offshore wind and energy storage policy proposals analyzed in this Policy Study include similar equity provisions to those required in CEJA for the developers of new wind and solar projects. However, the policy proposal for an underground high voltage transmission line did not include equity provisions. Further, the equity provisions found in CEJA may need to be built upon to ensure that sought benefits are indeed realized.

To ensure that equity provisions lead to equitable outcomes, it will be important to consider a project's entire supply chain; to ensure that benefits accrue to both residents of project areas and the project workforce; and to ensure that participating companies live up to the spirit, and not just the letter, of equity commitments. Policies intended to drive equitable outcomes should address each of the following: the company, the customer, the project location, and the workforce. Ideally, equity provisions folded into calling for substantial public financial support address all four of these pillars effectively.

iii) Allow for Flexibility in Timelines

The IPA should be granted flexibility to adjust delivery parameters and to conduct supplemental procurements if its initial procurement efforts are not fully successful, or if subsequent project attrition requires new procurements.

The Agency's experience in conducting competitive procurements for RECs from utility-scale wind and solar projects and administering programs to support community solar and distributed generation solar has demonstrated that project timelines may be delayed by a wide range of factors. Factors leading to such delays have included interconnection approvals, permitting delays, supply chain bottlenecks, and global health pandemics.

While setting target dates for policy implementation is an important tool for ensuring progress towards the State's clean energy goals, flexibility is also an important consideration. For example, rigid timelines can add risk to project developers and could increase financing costs. Further, any number of factors can impact the success of procurements. The market may also require additional time to understand the procurement processes for new types of resources.

iv) Bill Impacts Must Be Weighed Against the Cost of Inaction

The General Assembly should not look at bill impacts in isolation, but instead against the backdrop of alternatives.

Through modeling, the IPA has sought to develop a snapshot of a future scenario and then measure the costs and benefits of the adoption of three policies against that scenario. The introduction of these policies have discrete and severable costs, and the IPA believes it is necessary to be as transparent and forthright as possible about those costs. The primary audience for this Policy Study is the Illinois General Assembly, and the political consequences of a new or increased surcharge on customer electric bills may be borne by its members.

But identifying those discrete and severable costs is not the same as saying that the cost of action is greater than the cost of inaction. To illustrate this point, we have attempted to highlight other suites of benefits— such as emissions reductions, reliability improvements, and wholesale price impacts— demonstrating beneficial marginal impacts that are indeed real, but which do not perfectly net out against a line item utility bill surcharge.

For the IPA, we have also sought to quantify and share only those impacts which we could reliably measure. Costs resultant from a loss of load event may be felt as ripples across the State's entire economy. Even if not quantified within the four corners of this Policy Study, those costs are no less real.

v) Integrated Resource Planning

The General Assembly should create a centralized planning process to map out Illinois' energy future.

Public Act 103-0580 tasked the Agency to study the potential impacts of three different policy proposals, with each positioned as driven by the State's transition to a decarbonized, clean energy-focused energy economy. Meanwhile, the ICC has developed a Renewable Energy Access Plan that comprehensively and actionably outlines the path to an equitable, reliable, and affordable path to meeting Illinois' policy requirements for a clean electricity system. The IPA develops its Long-Term Renewable Resources Procurement Plan biannually to outline its approach to supporting the development of new wind and solar projects across the State. Illinois electric utilities have submitted multi-year integrated grid plans proposing distribution system planning in order to accelerate progress on Illinois clean energy and environmental goals. In 2025, the IPA, the ICC, and the Illinois Environmental Protection Agency will conduct a study of resource adequacy and reliability pursuant to Section 9.15(o) of the Environmental Protection Agency Act.

Each of these activities will examine key aspects of the transition to a clean energy economy, but none are themselves comprehensive.

Studying a specific energy storage procurement target does not provide answers on the amount of energy storage Illinois needs and on what timeline the storage is needed. Studying a pilot offshore wind project also does not answer the question of what the value of an offshore wind project is compared to land-based wind projects for Illinois or numerous other alternatives. Further, studying a specific proposed high voltage direct current transmission line proposal does not address what the transmission needs for Illinois are; nor does it provide an answer on the proper balance of incenting in-state development of renewable resources compared to harnessing the potential resources available across a wider geographic area.

In states that did not restructure their electric industry, developing an integrated resource plan is typically used to comprehensively address these types of broad questions. While restructuring has brought the value of competitive electricity markets to Illinois, a side effect of restructuring has been that there is no one entity tasked with asking these questions or conducting the necessary research needed to answer them. This is a significant planning gap for Illinois' clean energy future that must be addressed.

b) Energy Storage

vi) Appropriate Program Size, Scope, and Shape

Ensure that the Agency has flexibility to determine and adjust energy storage procurement goals to the levels sufficient to support Illinois' clean energy goals.

The State's need for robust energy storage policy is obvious and necessary to pair with aggressively supporting the development of new intermittent renewable resources under the Illinois RPS. As discussed in Section 5.b.ii, SB 1587 includes a goal of 7,500 MW utility-scale energy storage, which would be one of the largest in the country. This ambition may ultimately be wise given the parallel ambition of the State's 50% by 2040 RPS and full decarbonization by 2050 goal. However, this Policy Study examined the potential impacts of energy storage deployment in accordance with the procurement goals contained in SB 1587, rather than studying the optimal amount of energy storage needed in Illinois or the optimal characteristics governing its deployment.

SB 1587 calls on the IPA to "conduct an analysis to determine whether the contracted quantity of energy storage in energy storage capacity and energy storage duration is sufficient to support the State's renewable energy standards and carbon emission standards" beginning in 2026 and every two years thereafter. This provision is essential, but would benefit from targeted language allowing the IPA to adjust the storage procurement goals upward or downward, adjust geographical preferences, adjust the balance between 4-hour and longer-duration storage projects (including 10-hour and multi-day duration projects), adjust the compensation structure applicable to storage projects (including moving away from an indexed energy storage credit model if necessary), and make other midstream adjustments necessary to ensure that the projects incented pair most effectively with the State's needs. For example, the ICC's Renewable Energy Access Plan may create a new opportunity for a different geographic overlay, and the General Assembly would be wise to expressly authorize this flexibility in implementation.

vii) Provide Additional Resources to Support Storage Projects for Income-Eligible Households and Households in Environmental Justice Communities

The General Assembly could authorize a dedicated program modeled from the Illinois Solar for All Program to support storage for income-eligible customers and customers residing in environmental justice communities.

SB 1587 includes a provision that would allow the ICC to consider incentives to aggregators for customers residing in Equity Investment Eligible Communities, and that may help drive storage adoption in the communities. However, those incentives may not be sufficient to ensure robust participation by low-income households and may not provide benefits to income-eligible households that do not reside in an Equity Investment Eligible Community.

A dedicated storage program for income-eligible households would complement the existing Illinois Solar for All program and could provide such opportunities.

The General Assembly should also consider, as part of the storage program, what additional resources can be provided to income-eligible households to fund electrical system upgrades needed for storage installation because the upfront cost such upgrades may be barrier to limited income households, and the proposed tariff compensation does not address that barrier.

i) Consider How an Energy Storage Tariff Credit Interacts with the Smart Inverter Rebate

The General Assembly should ensure that the incentives from an Energy Storage Tariff Credit be calibrated with the smart inverter rebate for storage to ensure that the total compensation received by customers is appropriate.

The Smart Inverter Rebate contained in Section 16-107.6 of the Public Utilities Act contains an additional rebate, currently $300 per kilowatt-hour for residential projects, for smart inverters paired with energy storage. The base rebate for a solar smart inverter is currently $250 per kilowatt of residential solar nameplate capacity. SB 1587 proposes creating an additional incentive for installing storage administered through aggregators. Therefore, coordinating a tariff credit with the smart inverter rebate would provide simplified application processes for residential customers.

The Agency also suggests that the General Assembly may consider potential customer confusion if there are multiple incentives offered to support installing solar, and instead consider consolidating the incentives into one value stream.

ii) Explore Further Opportunities for Long-duration Energy Storage Systems

Related to the need for implementation flexibility outlined above, storage technologies face limitations in addressing the additional capacity needs associated with shifting from summer to winter peaks. Capacity shortfalls may also arise due to storage degradation. If renewable technologies outlast the paired storage, especially with short-duration batteries, shortfalls are likely to occur. Renewable generation will require quick replacement or longer duration storage to meet the shortfalls.

Storage implementation needs to be aligned with the long-run needs of variable renewable generation. Presently, SB 1587 calls only for the development of a firm energy resource plan to support "a minimum of 2 new long-duration or multi-day energy storage resources each with a rated capacity greater than 20 megawatts." The process for that Plan's approval before the ICC, or for the selection of those projects, is not clear from the bill. As load forecasts demonstrate concerns around longer-duration winter peaks, more attention should be paid to the potential benefits of longer-duration storage projects, including more aggressive procurement targets and a more defined process for plan development and procurement events within a storage bill.

iii) Consider Initial Forward Procurements

In recognition of the extensive (but necessary) timelines for procurement plan development, procurement plan approval, and building toward subsequent procurement events, both FEJA and CEJA called on the IPA to conduct initial competitive procurements to support the development of utility-scale wind and solar projects before the IPA's Long-Term Renewable Resources Procurement Plan's completion. Given the need for storage project deployment and the multitude of storage projects already populating PJM and MISO interconnection queues, the General Assembly may wish to adopt similar forward procurement requirements in SB 1587.

iv) Adopt Storage Valuation Requirements

The General Assembly previously enacted statewide property tax valuation methodologies for wind (35 ILCS 200/10-600 enacted in 2008) and solar (35 ILCS 200/10-720 enacted in 2018). Implementing a consistent method for valuing energy storage would not only provide developers with the ability to anticipate property tax implications for their projects, but would also foster a stable environment for energy storage development statewide. While this topic was outside of the scope of this Policy Study, after releasing the draft Policy Study, the Agency received a comment from the County Assessment Officers Association with this recommendation, and the IPA concurs.

c) Offshore Wind

i) Consider Implications of Recent Challenges for Offshore Wind

As the General Assembly develops policies to support offshore wind development in Illinois, it should consider the East Coast offshore wind projects that were cancelled in 2023 due to rising costs.

As discussed in Section 6.b.ii.1, there has been a wave of cancelations of offshore wind projects on the East Coast due to rising costs. Additionally, there have been several recent unsuccessful procurements for offshore wind. HB 2132 includes a rate cap for supporting offshore wind, and if the assumptions that the offshore wind industry has been using for project development costs (as reflected in the NREL study on Great Lakes wind development) are outdated, then the proposed rate cap may provide insufficient funding to support project development. Illinois would face similar situations to the East Coast states where projects have been cancelled. In the alternative, allowing for downstream cost adjustments should be weighed against the impact on ratepayers from authorizing a higher level of financial support.

ii) Require Further Information About Project Economics

Modeling demonstrated that the sought subsidy level found in HB 2132— an increase in the RPS rate impact cap from 4.25% to 4.5%, resulting in a budget of $33-$34 million annually—

could be insufficient to support the project's successful development, especially if the project faces any unexpected costs or development barriers. The General Assembly may wish to seek more information on project economics before authorizing a procurement event designed to result in successful project development, and should outline contingency plans should authorized funding prove insufficient— whether through authorizing the use of additional RPS collections, through a subsequent offshore wind procurement event, through utilizing the balance of expected contract expenditures to support onshore wind development, or some other approach.

iii) Evaluate Federal Funding Opportunities for Port Development

The General Assembly should consider the status of federal funding applications for Lake Michigan port development and consider flexible timelines to account for port construction when it considers approving procurements to support an offshore wind project.

Constructing an offshore wind project will require the development of new port facilities in Illinois. Federal funding could be available to help offset the cost of that development. However, failure to secure federal funding has the potential to increase project costs and could threaten or delay the viability of the project.

iv) Clarify Leasing of the Lakebed

The General Assembly should consider adopting the recommendations of the Lake Michigan Offshore Wind Advisory Report that clarify securing rights to the lakebed for offshore wind development.

As discussed in Section 6.c.ii.4.b, the process for securing rights to use the lakebed for offshore wind in a way that does not violate the public trust doctrine is not established in existing Illinois law, or in HB 2132. A framework for establishing this process can be found in the 2012 Lake Michigan Offshore Wind Advisory Report discussed in Chapter 6. That report lists twenty-four criteria, as demonstrated in Table 6-2, across four topic areas including environmental factors, marine factors, public infrastructure, and transportation/security.

v) Conduct Additional Environmental Review

The environmental impacts of offshore wind may need to be studied further by the appropriate agencies, including the Illinois Environmental Protection Agency and the Illinois Department of Natural Resources.

Section 6.c.ii.4 discusses the potential environmental impacts of an offshore wind project, including impacts to migratory birds, bats, and fish. Environmental reviews significantly delayed the now-suspended Icebreaker project in Lake Erie. The causes of the Icebreaker delays should be considered in Illinois, this would help to ensure that full environmental impacts are studied, which may result in reduced delays for an offshore wind project in Illinois.

vi) Conduct Additional Research on Lake Michigan Conditions

The General Assembly may wish to authorize and fund additional research on the geophysical characteristics of the potential areas for wind development.

Offshore wind development has been in oceans to date. Developing an offshore wind project in Lake Michigan may require additional research into the conditions of Lake Michigan that have not been adequately researched during oceanic wind project development. For example, the impact of icing on wind turbines has not been a factor for oceanic wind projects, and therefore is a risk that has not been fully addressed. Additional research into the conditions of Lake Michigan could include, but is not limited to, studies of icing, wave patterns, surficial sediments, seismic activity, and bedrock conditions.

vii) Determine the Point of Interconnection

Requiring additional information on the offshore wind project interconnection point and associated site improvements should be considered as a prerequisite condition for a contract award.

The Policy Study transmission reliability and grid resilience modeling looked at four potential interconnection points in the Lake Calumet region, all of which could be viable points of interconnection for the proposed offshore wind project. However, that modeling only looked at interconnection costs. Interconnecting the project would require the project developer to acquire nearby land and construct an electrical substation. The sites that could be used for the substation have not yet been determined, and thus, the cost of acquiring a site is not yet known. More information on the interconnection point and associated site development would help ensure the viability of the offshore wind project.

d) HVDC Transmission Line

i) Obtain More information on Renewable Resources to Be Developed

The Agency recommends that SOO Green provide additional information and commitments on the renewable energy resources that supply the line prior to obtaining approval of public support for the SOO Green line.

Information provided to the Agency by the project developer, SOO Green, indicated the expected resource mix of renewable energy resources, including wind, solar, and battery storage, that will be constructed in Iowa. A different generation mix was identified in filings with the Iowa Utilities Board.

The Agency understands that the developers of the SOO Green line are in discussions with potential renewable energy project developers in Iowa, however, no firm commitments have been made and existing or proposed projects have not been identified. The SOO Green line specifications are currently dependent on assumptions that these resources will be available. This creates a risk that if the line is constructed but new renewable projects are not built in Iowa to supply the power (and provide RECs), then the line could potentially transmit non-renewable energy into Illinois, or could transmit less energy overall, which would be contrary to Illinois' clean energy goals**.** Additional information about these projects would also allow the General Assembly to further understand the dynamics of supporting out-of-state renewable energy project development versus those that would be developed in Illinois.

ii) Require Equity Commitments

Equity commitments should apply to both the SOO Green HVDC transmission line construction and to any renewable energy development in Iowa for projects producing RECs paid for by Illinois ratepayers.

The draft legislation to support the SOO Green HVDC transmission line does not include any equity commitments. Illinois established a strong equity framework through the Equity Accountability Standard contained in Section 1-75(c-10) of the Illinois Power Agency Act. This standard applies to projects participating in the Agency's competitive procurements to support utility-scale renewable energy projects; the Illinois Shines program to support solar for homes, businesses, and community solar projects; projects participating in the Coal-to-Solar procurements; and projects that support the Large Customer Self-Direct Program. The SOO Green line and associated renewable energy projects should be held to the same standard.

Doing so may require some adaptations of the standard to address work conducted outside of Illinois, or the geographical limitations inherent in supporting a single project with a defined location. If public interest criteria is met, adjacent state renewable energy projects may participate in the IPA's Indexed REC procurement events, and the IPA has adapted implementation of minimum equity standards and prevailing wage requirements to those projects. It is important to provide a level playing field and to provide consistent expectations of the private entities that are supported through state-administered programs and procurements, which will help ensure that the equity coals of CEJA are maintained.

iii) Resolve Capacity Resource Qualification and Accreditation Issues

The Agency recommends that the General Assembly include provisions that ensure any unresolved capacity market participation issues for SOO Green are satisfactorily resolved prior to committing ratepayer funds to support the project.

As discussed in Section 7.f.i, the ability of SOO Green to provide capacity to the PJM capacity market has multiple components that have not yet been determined, including the accreditation level of the project and the type of capacity resource the project would qualify as (if the project would qualify).

The proposed legislation utilizes a procurement model that has a strike price with energy and capacity values netted out, leaving the residual REC price to be paid for by Illinois ratepayers. Therefore, the value of capacity payments that can be realized by SOO Green is of keen concern for Illinois ratepayers. If SOO Green is not able to participate in PJM capacity markets at the forecasted levels, costs to Illinois ratepayers would increase. Furthermore, the state of Illinois would be left supporting a project that would not count toward PJM resource adequacy requirements, resulting in the need for more qualifying resources and potentially higher clearing prices.

iv) Manage Rate Impact Timing

The Agency recommends that the General Assembly consider the timing of cost recovery to support the SOO Green HVDC transmission line, and in the alternative, consider if collections should not begin until a later date in order to decrease the short-term rate impacts to Illinois ratepayers.

The proposed legislation to support the SOO Green HVDC transmission line would have utilities begin collecting tariffed charges from ratepayers beginning in 2025, while actual payments to SOO Green would not start until the project commences operations and begins delivering RECs. This will create a short-term rate impact on Illinois ratepayers where they pay for the project prior to seeing any benefits from it.

The benefit of this approach is that it would build up a substantial balance of funds to ensure sufficient funding once payments to the project commence. Presumably, if the project were not completed and the applicable REC delivery contracts are terminated, those funds would be returned to ratepayers. However, the General Assembly should consider if the timing of collecting funds to support SOO Green should be revised. In contrast to the proposed legislation for SOO Green, HB 2132 (the proposed policy for utility-scale offshore wind in Lake Michigan) includes language stating that funds will not be collected from ratepayers until the project is energized and delivering RECs.

v) Create a New System for Managing Bid Prices and Determining Public Support

SOO Green's draft legislation calls on the Illinois Capital Development Board to "calculate a range of capital costs that it believes would be reasonable for an HVDC transmission line of similar specifications to an applicant high voltage direct current transmission line" in determining a public benchmark price above which an HVDC REC contract would not be considered. This approach stands in stark contrast to the approach used by the IPA for energy procurements, capacity procurements, and Indexed REC procurements, through which the IPA's Procurement Administrator develops a confidential benchmark price subject to Illinois Commerce Commission review and approval.

The IPA is not clear on whether the Capital Development Board has the capacity to take on this work or what benefits this process departure offers back in ensuring a sufficiently competitive procurement process. Consequently, the General Assembly may seek a procurement process that better mirrors those traditionally used in IPA energy, capacity, and renewable energy credit procurements.