U.S. House Committee on Energy and Commerce

Subcommittee on Environment, Manufacturing, and Critical Materials

"Clean Power Plan 2.0: EPA's Latest Attack on Electric Reliability"

[June 6, 2023]

1. Arizona Department of Environmental Quality Letter to EPA, May 23, 2023, submitted by the Majority.
2. Edison Electric Institute Letter to Administrator Regan, May 23, 2023, submitted by the Majority.
3. McGuireWoods LLP Letter to Administrator Regan, May 23, 2023, submitted by the Majority.
4. National Rural Electric Cooperative and American Public Power Association Letter to Administrator Regan, May 24, 2023, submitted by the Majority.
5. Arkansas Electric Cooperative Corporation Letter to Administrator Regan, May 25, 2023, submitted by the Majority.
6. North Carolina Electric Membership Corporation Letter to Administrator Regan, May 26, 2023, submitted by the Majority.
7. U.S Chamber of Commerce Letter to Administrator Regan, May 26, 2023, submitted by the Majority.
8. Association of Air Pollution Control Agencies and National Association of Clean Air Agencies Letter to Mr. Joseph Goffman of EPA, May 30, 2023.
9. EPA Clean Air Act Section 111 Regulation of Greenhouse Gas Emissions From Fossil Fuel-Fired Electric Generating Units Presentation
10. America's Power Letter to Chairman Johnson and Ranking Member Tonko, June 5, 2023, submitted by the Majority.
11. Energy Transition in PJM: Resource Retirements, Replacements, and Risks, February 24, 2023, submitted by the Majority.
12. North American Electric Reliability Corporation 2022 Long-Term Reliability Assessment, December 2022, submitted by the Majority.
13. North American Electric Reliability Corporation 2023 Summer Reliability Assessment, May 2023, submitted by the Majority.
14. Portland Cement Association Letter to Chairman Johnson and Ranking Member Tonko, June 6, 2023, submitted by the Majority.
15. Texas General Land Office Letter to Administrator Regan, May 22, 2023, submitted by Rep. Pfluger.
16. Governor Glenn Youngkin Letter to Administrator Regan, June 5, 2023, submitted by Chairman Johnson.
17. Report from Wilson Energy Economics entitled, "Maintaining the PJM Region's Robust Reserve Margins," May 2023, submitted by Rep. Sarbanes.

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

Katie Hobbs
Governor

Karen Peters
Director

Submitted online via https://www.regulations.gov/

May 23, 2023

U.S. Environmental Protection Agency
EPA Docket Center
Docket ID Number: EPA-HQ-OAR-2023-0072
Mail Code 28221T
1200 Pennsylvania Avenue NW
Washington, DC 20460

Re: U.S. Environmental Protection Agency's "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule", Docket ID Number: EPA-HQ-OAR-2023-0072

To whom it may concern:

ADEQ appreciates the opportunity to comment on EPA's proposed "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule," collectively the "Power Sector GHG Proposal," 88 FR 33240 (May 23, 2023).

EPA's proposed rule established a deadline of July 24, 2023 for public comment. ADEQ is requesting that EPA extend the comment period because the proposal is technically complex and will have a substantial impact on the electricity generation sector in Arizona. A thorough review of the proposal and development of a detailed substantive comment letter will require more time than the 60-day comment period initially provided in the proposal.

ADEQ's analysis of the likely impact of the proposal on affected Arizona sources will require detailed technical, permit, and legal review coordinated across multiple agency sections. Additionally, EPA's proposed emission guidelines require extensive evaluation for how ADEQ would develop a plan to implement this proposal. ADEQ's evaluation of the proposal is still on-going at this time.

ADEQ requests that EPA extend the public comment period by at least 30 days and notify the public of the extension as soon as possible and well in advance of the July 24 deadline so commenters may make full use of the additional time.

ADEQ appreciates EPA's need for adequate time to consider comments, conduct any additional analyses, develop the final rule package, and complete agency and interagency reviews. However, this need should also be balanced against the public's interest to have adequate time to consider and respond to EPA's complex proposal with more thorough and detailed comments. ADEQ believes that 60 days is insufficient time for public comment, especially given the complexity of the proposal.

ADEQ appreciates the opportunity to provide these comments on EPA's Power Sector GHG Proposal. If you have any questions, please contact Daniel Czecholinski, Air Quality Division Director, at 602-771-4684 or czecholinski.daniel@azdeq.gov.

Thank you for your consideration of ADEQ's comments.

Sincerely,

Daniel Czecholinski
Air Quality Division Director

EEI
Edison Electric
INSTITUTE

Emily Sanford Fisher
Executive Vice President, Clean Energy,
and General Counsel & Corporate Secretary

May 23, 2023

Hon. Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20004

Dear Administrator Regan:

The Edison Electric Institute (EEI) requests that the U.S. Environmental Protection Agency (EPA or Agency) provide a brief, 30-day extension of the public comment period for the proposed rules, *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (Proposed 111 Rules). 88 *Fed. Reg.* 33,240 (May 23, 2023).

EEI is the association that represents all U.S. investor-owned electric companies. Our members provide electricity for more than 235 million Americans and operate in all 50 states and the District of Columbia. As a whole, the electric power industry supports more than seven million jobs in communities across the United States. In addition to our U.S. members, EEI has more than 65 international electric companies as International Members, and hundreds of industry suppliers and related organizations as Associate Members.

Today, the Proposed 111 Rules were published in the *Federal Register*, starting the clock for a 60-day comment period. This complex set of proposals, which EPA first made public less than two weeks ago, is inextricably bound up in our industry's ongoing clean energy transition, seeking both to reinforce the progress already made in reducing carbon emissions and to accelerate the deployment of critical, but still developing clean energy technologies. Electric companies want to provide robust, technical comments in response to the Proposed 111 Rules and the related technical analysis and modeling. Getting these rules right is essential to the continued provision of affordable, reliable, and clean energy to electricity customers across the country.

Moreover, a brief extension is warranted because the Proposed 111 Rules contain numerous elements that overlap with EPA's recently proposed Effluent Limitations Guidelines (ELG), legacy coal combustion residual (CCR) Surface Impoundments rules, and Mercury and Air Toxics (MATS) Risk and Technology Review (RTR). EPA has repeatedly indicated its intent to regulate the power sector through a holistic approach, recognizing that the Agency has multiple authorities with overlapping statutory timelines that affect EEI members' plans regarding coal- and gas-based electric generating units and the continued clean energy transformation. Additional time is needed to assess the Proposed 111 Rules from this holistic perspective

Accordingly, given the complexity of the Proposed 111 Rules—especially the proposed limits for new and existing gas and the coal retirement subcategories—and their interaction with other, recent EPA proposals, our members would benefit from additional time to analyze and provide substantive feedback to EPA on how all of these proposals might impact our industry's ongoing clean energy transition and to ensure that the regulatory framework being considered by EPA is consistent with our commitment to providing affordable, reliable, and increasing clean power to customers.

Thank you for your consideration of this request. We would appreciate a response well before the 60-day comment period elapses, especially as two major holidays are encompassed in this period, which will create complications for scheduling critical meetings to review and assess the Proposed 111 Rules and draft comments. We have made good use of the time since EPA made the proposals public, which has underscored the need for additional time to draft and file comments.

Sincerely,

Emily Sanford Fisher

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May 23, 2023

Via Electronic Mail
Filed in EPA Docket ID No. EPA-HQ-OAR-2023-0072

The Honorable Michael S. Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: Request for Extension of Comment Period

Dear Administrator Regan:

On May 23, 2023, the U.S. Environmental Protection Agency ("EPA") published a notice of proposed rulemaking in the Federal Register entitled "New Source Performance Standards for Greenhouse Gas Emission From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" ("Proposed Rules"). 88 Fed. Reg. 33,240 (May 23, 2023). That notice established a 60-day deadline for public comment on the Proposed Rules. This letter is being sent on behalf of the Power Generators Air Coalition ("PGen")[1] to request that EPA extend this deadline by an additional 60 days to September 20, 2023.

PGen members own and operate fossil fuel-fired electric generating units (EGUs) that are the subject of the Proposed Rules, and many have resource plans that call for the addition of new "firm" power from fossil fuel generation that are also the subject of this rulemaking. As a result, PGen members have a powerful interest in the Proposed Rules and have been very engaged on these issues with EPA, filing comments with EPA during the pre-proposal stage of this rule[2] and meeting with EPA personnel in Research Triangle Park on November 17, 2022.

[1] PGen is an incorporated nonprofit 501(c)(6) organization whose members are diverse electric generating companies—public power, rural electric cooperatives, and investor-owned utilities—with a mix of solar, wind, hydroelectric, nuclear, and fossil generation. Our members include leaders in the fundamental transition to cleaner energy that is currently occurring in the industry. PGen and its members work to ensure that environmental regulations support a clean, safe, reliable, and affordable electric system for the nation. Additional information about PGen and its members can be found at https://pgen.org.

[2] Comments of the Power Generators Air Coalition to EPA's Pre-Proposal Non-Rulemaking Docket on Reducing Greenhouse Gas Emissions from New and Existing Fossil Fuel-Fired Electric Generating Units, Docket ID No. EPA-HQ-OAR-2022-0723 (Dec. 22, 2022).

Additional time is necessary for the public to develop meaningful comments on the Proposed Rules. As EPA undoubtedly knows, the Proposed Rules are extraordinarily complex and contain five separate proposed actions: (1) revised new source performance standards (NSPS) for greenhouse gas (GHG) emissions from new fossil fuel-fired stationary combustion turbine electric generating units (EGUs); (2) revised NSPS for GHG emissions from modified fossil fuel-fired steam generating EGUs; (3) emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs; (4) emission guidelines for GHG emissions from existing stationary combustion turbines; and (5) repeal of the Affordable Clean Energy Rule. These proposed rules raise many substantial issues that require thorough analysis. States and affected members of the public are only just beginning to undertake the modeling and analytical work necessary to understand and comment on the Proposed Rules, and they cannot reasonably complete that important work within the current comment period. For that reason, PGen respectfully requests an additional 60 days, until September 20, 2023, to review and prepare comments on the Proposed Rules.

Because PGen members own and operate EGUs that will be subject to the Proposed Rules, the ability to prepare comprehensive comments on these rules is of great importance to PGen. Thank you for your consideration of this request.

Respectfully submitted,

Allison D. Wood
Counsel to the Power Generators Air Coalition

cc: Joseph Goffman, Principal Deputy Assistant Administrator
Christian Fellner, Sector Policies and Programs Division, OAQPS
Lisa Thompson, Sector Policies and Programs Division, OAQPS

NRECA
America's Electric Cooperatives

AMERICAN PUBLIC POWER ASSOCIATION
Powering Strong Communities

May 24, 2023

Administrator Michael S. Regan
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Request for 60-Day Extension of Comment Deadline for New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (Docket ID No. EPA-HQ-OAR-2023-0072); 88 Fed. Reg. 33, 240 (May 23, 2023)

Dear Administrator Regan,

On May 23, 2023, the U.S. Environmental Protection Agency (EPA) published a proposed rule to limit greenhouse gas emissions from new and existing fossil fuel-fired electric generating units.[1] EPA has provided a 60-day public comment period that will end on July 24, 2023. For the reasons discussed below, the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) (together the Associations) respectfully request that the EPA extend the comment period by an additional 60 days to ensure there is adequate time to fully evaluate and comment on the proposal and underlying technical supporting documents.

NRECA is the national trade association representing nearly 900 not-for-profit electric cooperatives that deliver power to 42 million people and serve 92 percent of the nation's persistent poverty counties. NRECA members include 63 generation and transmission (G&T) cooperatives and 832 distribution cooperatives. As not-for-profit, consumer-owned utilities, electric cooperatives are deeply concerned about maintaining affordable and reliable electric service for our members.

APPA is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 96,000 people they employ. Our association advocates and advises on electricity policy, technology, trends, training, and operations. Our members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power.

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[1] New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 88 FR 33240 (May 23, 2023).

The proposal has significant economic and operational implications for the electric sector. There is a substantial amount of material to review to fully understand EPA's proposal and provide meaningful comment. The proposal includes the 181-page proposed rule, a 359-page regulatory impact analysis, and references several technical supporting documents that have yet to be posted to the rulemaking docket. EPA has also solicited comment on dozens of various topics in the proposed rule preamble. The Associations and their members need additional time to evaluate EPA's proposal, the supporting documents and analyses, and develop responses to EPA's requests for comment.

In addition to the proposed rule, there are currently open comment periods on other complex EPA proposed rules directly affecting cooperatives and public power utilities, specifically:

- Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category that ends May 30;
- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review that ends June 23; and
- Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments that ends July 17.
- Cooperatives also have an interest in grid reliability and electric infrastructure impacts of the greenhouse gas emissions standards proposed rules for both heavy duty and light duty vehicles with their emphasis on increasing uptake of electric vehicles -- those comment periods run through June 16 and July 5, respectively.

These concurrent comment periods on five other extremely technical and significant proposed rules create challenges as cooperatives and public power utilities work to thoughtfully respond to each proposal.

Finally, when EPA first proposed New Source Performance Standards (NSPS) for fossil fuel-fired electric generating units in 2014, it provided a 120-day comment period following a 60-day extension. And when EPA proposed emissions guidelines for existing sources later that year, the agency's initial 120-day comment period was later extended by an additional 45 days. Importantly, those comment periods were not concurrent – the NSPS comment period ended more than a month before the comment period for the proposed emissions guidelines opened. Providing half of that comment period on this most recent power plant proposal would be woefully insufficient for the type of input EPA has requested, particularly because the package includes five actions in one.[2]

For these reasons, the Associations respectfully request a 60-day extension of the comment period. Providing an extension of the comment period will allow all stakeholders additional time to analyze the proposal and provide more thoughtful comments.

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[2] "The EPA is proposing revised new source performance standards (NSPS), first for GHG emissions from new fossil fuel-fired stationary combustion turbine EGUs and second for GHG emissions from fossil fuel-fired steam generating units that undertake a large modification, based upon the 8-year review required by the CAA. Third, the EPA is proposing emission guidelines for GHG emissions from existing fossil fuel-fired steam generating EGUs, which include both coal-fired and oil/gas-fired steam generating EGUs. Fourth, the EPA is proposing emission guidelines for GHG emissions from the largest, most frequently operated existing stationary combustion turbines and is soliciting comment on approaches for emission guidelines for GHG emissions for the remainder of the existing combustion turbine category. Finally, the EPA is proposing to repeal the Affordable Clean Energy (ACE) Rule." 88 FR 33240 (May 23, 2023).

The Associations appreciate EPA's consideration of their request and look forward to a response. If you have questions about this request, please do not hesitate to contact me at (703) 907-5861 or Ms. Carolyn Slaughter on behalf of APPA at (202) 467-2900.

Sincerely,

Dan Bosch
Regulatory Affairs Director
National Rural Electric Cooperative Association

Carolyn Slaughter

Carolyn Slaughter
Senior Director, Environmental Policy
American Public Power Association

Arkansas Electric
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Reliable • Affordable • Responsible

1 Cooperative Way
P.O. Box 194208
Little Rock, Arkansas 72219-4208
(501) 570-2200

May 25, 2023

Administrator Michael S. Regan
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

RE: Request for 60-Day Extension of Comment Deadline for New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (Docket ID No. EPA-HQ-OAR-2023-0072); 88 Fed. Reg. 33, 240 (May 23, 2023)

Dear Administrator Regan,

On May 23, 2023, the U.S. Environmental Protection Agency (EPA) published a proposed rule to limit greenhouse gas emissions from new and existing fossil fuel-fired electric generating units. EPA has provided a 60-day public comment period that will end on July 24, 2023. For the reasons discussed below, Arkansas Electric Cooperative Corporation (AECC) respectfully requests that the EPA extend the comment period by an additional 60 days to ensure there is adequate time to fully evaluate and comment on the proposal and underlying technical supporting documents.

The proposal has significant economic and operational implications for the electric sector. There is a substantial amount of material to review to fully understand EPA's proposal and provide meaningful comments. The proposal includes the 181-page proposed rule, a 359-page regulatory impact analysis, and references several technical supporting documents that have yet to be posted to the rulemaking docket. EPA has also solicited comments on dozens of various topics in the proposed rule preamble. AECC needs additional time to evaluate EPA's proposal, the supporting documents and analyses, and develop responses to EPA's requests for comment.

In addition to the proposed rule, there are currently open comment periods on other complex EPA proposed rules directly affecting cooperatives and public power utilities, specifically:

- Supplemental Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category that ends May 30;

- National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-Fired Electric Utility Steam Generating Units Review of the Residual Risk and Technology Review that ends June 23; and
- Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals From Electric Utilities; Legacy CCR Surface Impoundments that ends July 17.

These concurrent comment periods on three other extremely technical and significant proposed rules create challenges as stakeholders work to thoughtfully respond to each proposal.

Finally, when EPA first proposed New Source Performance Standards (NSPS) for fossil fuel-fired electric generating units in 2014, it provided a 120-day comment period following a 60-day extension. And when EPA proposed emissions guidelines for existing sources later that year, the agency's initial 120-day comment period was later extended by an additional 45 days. Importantly, those comment periods were not concurrent – the NSPS comment period ended more than a month before the comment period for the proposed emissions guidelines opened. Providing half of that comment period on this most recent power plant proposal would be woefully insufficient for the type of input EPA has requested, particularly because the package includes five actions in one.

For these reasons, AECC respectfully requests a 60-day extension of the comment period. Providing an extension of the comment period will allow all stakeholders additional time to analyze the proposal and provide more thoughtful comments.

AECC appreciates EPA's consideration of their request and looks forward to a response. If you have questions about this request, please do not hesitate to contact stephen.cain@aecc.com or 501.570.2420.

Sincerely,

Buddy Hasten
President/CEO

NC Electric Membership Corporation
A Touchstone Energy® Cooperative

May 26, 2023

Administrator Michael S. Regan
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Request for 60-Day Extension of Comment Deadline for New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (Docket ID No. EPA-HQ-OAR-2023-0072); 88 Fed. Reg. 33, 240 (May 23, 2023)

Dear Administrator Regan,

On May 23, 2023, the U.S. Environmental Protection Agency (EPA) published a proposed rule to limit greenhouse gas emissions from new and existing fossil fuel-fired electric generating units ("Proposed Rule"). EPA has provided a 60-day public comment period that will end on July 24, 2023.

On May 24, 2023, the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) (together the Associations) respectfully requested that the EPA extend the comment period for the Proposed Rule by an additional 60 days to ensure there is adequate time to fully evaluate and comment on the proposal and underlying technical supporting documents.

North Carolina Electric Membership Corporation (NCEMC) is one of the largest generation and transmission electric cooperatives in the nation, serving the full or partial requirements of twenty-five (25) member distribution cooperatives that collectively serve a million homes and businesses across 93 of the state's 100 counties, primarily in rural areas. NCEMC owns power generation assets, including fossil-fuel fired electric generating units; purchases electricity at wholesale from suppliers that currently rely on fossil fuel-fired electric generating units; coordinates transmission resources for its member distribution cooperatives; and partners with its members to integrate distributed energy resources across the grid. NCEMC has established a voluntary goal of achieving net-zero greenhouse gas emissions (GHG) by 2050 without impairing reliability or affordability. The Proposed Rule has significant economic and operational implications for the electric sector, including for

NCEMC and its ability to reliably and affordably achieve its voluntary net-zero GHG goal. Providing a 60-day extension of the comment period will allow all stakeholders, including NCEMC, additional time to analyze the proposal and provide more thoughtful comments.

For the reasons set out above and in the Associations' May 24, 2023 request for a 60-day extension of the comment period, NCEMC also respectfully requests a 60-day extension of the comment period for the Proposed Rule. NCEMC appreciates EPA's consideration of this request and looks forward to a response.

If you have questions about this request, please do not hesitate to contact me.

Sincerely,

Charlie Bayless
SVP & General Counsel

Phone: (919) 875-3085
Email: charlie.bayless@ncemcs.com

/rhg

U.S. Chamber of Commerce

1615 H Street, NW
Washington, DC 20062-2000
uschamber.com

May 26, 2023

Submitted via REGULATIONS.GOV

Honorable Michael Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue NW
Washington, DC 20004

Re: Proposed Rule, Environmental Protection Agency; New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule (88 Fed. Reg. 33,240-33,420, May 23, 2023)

Dear Administrator Regan:

The U.S. Chamber of Commerce ("Chamber") respectfully requests a comment period extension of at least 60 days for the proposed rules published earlier this week in the *Federal Register* and entitled *New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule* (or "Powerplant Rules").[1] That publication commenced a rather abbreviated 60-day timeline for public comment to the Environmental Protection Agency (EPA) on the Powerplant Rules, which were made public only shortly before such *Federal Register* publication.[2] Given the significant breadth and scope of the proposed rules, the multiple actions proposed therein, and the numerous stakeholders potentially impacted by the Powerplant Rules, a minimum 60-day extension to the comment deadline in this proceeding is warranted.

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[1] 88 Fed. Reg. 33,240 (May 23, 2023).

[2] For comparison's sake, when EPA issued its similarly focused Clean Power Plan an initial 90-day comment period was provided to interested stakeholders. That comment period was then extended by an additional 45 days for a total comment period of 135 days. The CPP covered only existing generating sources, while the Powerplant Rules propose new regulations for both new, reconstructed, and existing power generation facilities.

The Chamber represents a significant portion of the business community that either would be directly or indirectly impacted by the Powerplant Rules. The broad Chamber umbrella represents numerous interested entities, inclusive of many electric utilities directly regulated by the rule and the millions of businesses large and small that depend upon reliable and affordable electricity to power their livelihoods. The Powerplant Rules propose significant changes to how our nation generates electricity and, as such, these proposals have the potential to significantly impact the availability and cost of this essential commodity on businesses, individuals, and families. These far-reaching impacts across a broad stakeholder audience merit sufficient additional time for the assembly and development of thoughtful and comprehensive comments responsive to EPA's proposal.

In addition, the Powerplant Rules are extraordinary and technically complex, while also including five separate regulatory actions issued under two significant subsections of the Clean Air Act (CAA). While the EPA has previously issued separately its power plant regulations under sections 111(b) and 111(d) of the CAA, the current EPA proposal stretches across both new and existing electric generation facilities utilizing coal, natural gas, and/or oil as their feedstock. In particular, the EPA is proposing:

(1) Revised new source performance standards (NSPS) for greenhouse gas emissions from new fossil fuel-fired stationary combustion turbine electric generating units (EGUs);

(2) Revised NSPS for greenhouse gas emissions from modified fossil fuel-fired steam generating EGUs;

(3) Emission guidelines for greenhouse gas emissions from existing fossil fuel-fired steam generating EGUs;

(4) Emission guidelines for greenhouse gas emissions from existing stationary combustion turbines; and

(5) Repeal of the Affordable Clean Energy Rule.

Moreover, due to the significance of the proposed rules and their potential impact upon approximately 60 percent of the nation's current electricity supply, adequate additional time for meaningful stakeholder feedback should be beneficial in the EPA's need to balance its regulatory proposal with the reliability and affordability of electric generation.

In light of these considerations, a minimum of 60 days of additional commenting time is needed to ensure that affected members of the business community are able to provide accurate and appropriately detailed comments on the proposal that will provide adequate information to the agencies to inform the development of any final rule. Thank you for considering our comments, and please contact us if you would like any additional information.

Sincerely,

Marty Durbin
President, Global Energy Institute
and Senior Vice President, Policy
U.S. Chamber of Commerce

May 30, 2023

Mr. Joseph Goffman
Principal Deputy Assistant Administrator
Office of Air and Radiation (OAR)
U.S. Environmental Protection Agency (EPA)
1200 Pennsylvania Avenue, N.W. Washington, D.C. 20460

Submitted electronically to goffman.joseph@epa.gov and via the Federal eRulemaking Portal at https://www.regulations.gov

Subject: Comment period extension for U.S. EPA's proposed rulemaking, "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule" (Docket ID No. EPA-HQ-OAR-2023-0072)

Dear Mr. Goffman:

The Association of Air Pollution Control Agencies (AAPCA) and National Association of Clean Air Agencies (NACAA) respectfully request an extension of the deadline for submitting comments on U.S. EPA's recently proposed "New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units: Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule."[1] AAPCA and NACAA represent state and local air agencies that serve as co-regulators with U.S. EPA, responsible for implementing federal Clean Air Act regulations. The Associations seek an additional 30 days, until August 21, to allow for thorough review of the proposal and the development of substantive comments.

U.S. EPA's proposal, published in the *Federal Register*[2] less than two weeks after being publicly released,[3] would establish greenhouse gas (GHG) emissions standards for power plants under section 111 of the Clean Air Act and require air agencies to design state plans for implementing the final rule. The proposed rule is nearly 600 pages in length, supported by a 359-page Regulatory Impact Analysis, detailed power sector modeling, and approximately 80 pages of regulatory text. These documents are all exceedingly complex, with U.S. EPA soliciting comment on more than 200 areas in just the proposed rule.

[1] 88 Federal Register 33240–33420 (May 23, 2023).
[2] *Ibid.*
[3] U.S. EPA, "EPA Proposes New Carbon Pollution Standards for Fossil Fuel-Fired Power Plants to Tackle the Climate Crisis and Protect Public Health," May 11, 2023.

Addressing the substantial policy, legal, and technical components of a rulemaking of this magnitude requires significant work to coordinate staff analysis and draft comments. State and local agency timelines for review may also need to accommodate multiple interagency approval processes. Providing a full 90 days for comment will improve meaningful, applicable input from state and local air agencies, which have expertise that will be critical to successful implementation of the final rule.

Thank you for your consideration of this comment period extension request. If you have any questions, please reach out to either AAPCA's Executive Director, Jason Sloan (jsloan@csg.org or 859-244-8043), or NACAA's Executive Director, Miles Keogh (mkeogh@4cleanair.org or 571-970-6795).

Sincerely,

Jason Sloan
Executive Director, AAPCA

Miles Keogh
Executive Director, NACAA

CLEAN AIR ACT SECTION 111 REGULATION OF GREENHOUSE GAS EMISSIONS FROM FOSSIL FUEL-FIRED ELECTRIC GENERATING UNITS

OUTLINE

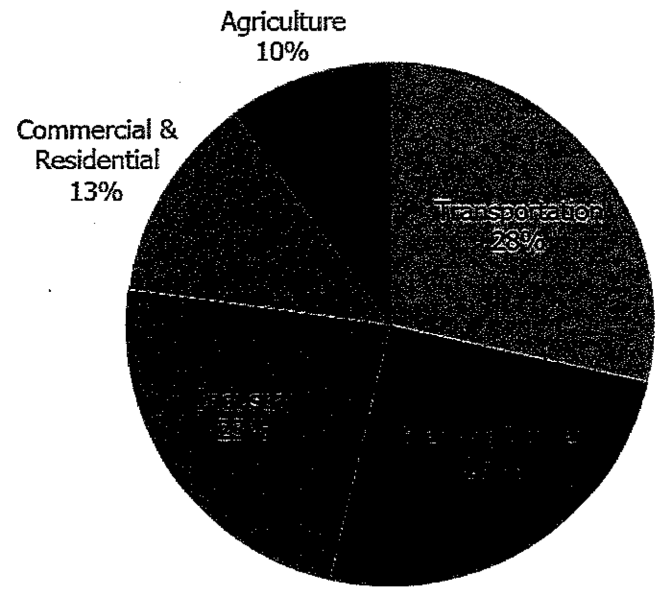
- Overview
- Details about the Proposals
  - New Source Performance Standards (NSPS)
  - Emission Guidelines
  - State Plan Development
  - Repeal of the Affordable Clean Energy (ACE) Rule
- Summary of Benefits, Costs, and Economic Impacts

OVERVIEW

On May 11, 2023, EPA issued proposed Clean Air Act emission limits and guidelines for carbon dioxide (CO_2) from fossil fuel-fired power plants based on cost-effective and available control technologies.

In 2021, the power sector was the largest stationary source of greenhouse gases (GHGs), emitting 25 percent of the overall domestic emissions.

Total U.S. Greenhouse Gas Emissions by Economic Sector in 2021



U.S. Environmental Protection Agency (2023). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021

OVERVIEW

Technology-based standards that leverage cost-effective and available technologies

- Proposing standards and emission guidelines for new and existing fossil fuel-fired power plants based on proven, cost-effective control technologies.
  - Set limits for new gas-fired combustion turbines, existing coal, oil and gas-fired steam generating units, and certain existing gas-fired combustion turbines
- Consistent with EPA's traditional approach to establishing pollution standards under Clean Air Act section 111, based on technologies such as carbon capture and sequestration/storage (CCS), low-GHG hydrogen co-firing, and natural gas co-firing, which can be applied directly to power plants that use fossil fuels

Reduces climate and other health-harming pollution

- Through 2042, EPA estimates the climate and health net benefits of the standards on new gas and existing coal-fired power plants are **up to $85 billion**, an annual net benefit of up to roughly $6 billion
- Proposal for coal and new natural gas is expected to avoid up to 617 million metric tons of carbon dioxide (CO_2) through 2042, equivalent to annual national CO2 emissions from natural-gas fired power generation in 2021
- Proposed standard for existing natural gas is expected to avoid up to 407 million metric tons of CO2

Build on decades of technology advancements and momentum from recent changes in the sector driven by the Inflation Reduction Act and the Bipartisan Infrastructure law

- Proposals provide utilities options for meeting these standards as well as ample time to plan and invest for compliance, leverage the clean energy incentives and opportunities provided in the Inflation Reduction Act, and continue to support a reliable supply of affordable electricity.

OVERVIEW

Flexible proposal and with time and options to plan investments

- EPA considered time alongside technology to give utilities options for planning their investments.
- Consider how different types of units are used and extensive industry input to EPA about unit operating horizons and lead times for control technologies.
  - Used this input to evaluate control technologies and create subcategories that give units flexibility.

Part of a larger, comprehensive suite of regulatory actions for power plants

- The Administrator announced this suite of actions over a year ago to fully address the climate, health, and environmental burdens from power plants, which all too often fall hardest on vulnerable or overburdened communities.
- Over the last few months, EPA:
  - issued a final "Good Neighbor Rule" to reduce smog-forming pollution from power plants and industrial facilities in 23 states;
  - finalized a finding that it is "appropriate and necessary" to regulate hazardous air pollutants from power plants under the Clean Air Act, restoring the legal foundation for our Mercury and Air Toxics Standards
  - proposed to strengthen MATS for mercury and other hazardous air pollutants from coal-fired power plants; and
  - proposed to strengthen limitations on wastewater discharges from power plants under the Clean Water Act.

REGULATORY HISTORY

NSPS; Clean Air Act section 111(b)

- In 2015, EPA established greenhouse gas (GHG) standards for fossil fuel-fired steam generating units and fossil fuel-fired stationary combustion turbines.
- In 2018, EPA proposed to revise the NSPS but never finalized the proposal.

Emission Guidelines; Clean Air Act section 111(d)

- In 2015, EPA finalized the Clean Power Plan (CPP) to address GHGs from existing electric generating units (EGUs).
- In 2019, EPA repealed and replaced the CPP with the Affordable Clean Energy (ACE) rule.
- In 2021, the D.C. Circuit Court vacated the ACE rule, which included the CPP repeal.
- In 2022, the Supreme Court reversed the vacatur of the ACE rule and upheld the CPP Repeal.

TECHNOLOGY-BASED STANDARDS

As laid out in section 111 of the Clean Air Act, the proposed new source performance standards (NSPS) and emission guidelines reflect the application of the best system of emission reduction (BSER) that, taking into account costs, energy requirements, and other statutory factors, is adequately demonstrated for the purpose of improving the emissions performance of the covered electric generating units.

Proposing technology-based standards under Clean Air Act section 111, including:

- Updates to the New Source Performance Standards (NSPS) for fossil fuel-fired stationary combustion turbines (generally natural gas-fired)
- Emission guidelines for large, frequently used existing fossil fuel-fired stationary combustion turbines (generally natural gas-fired)
- Emission guidelines for existing fossil fuel-fired steam generating EGUs (generally coal-fired)

PROPOSED BSER LEVELS FOR 111(B) - NEW STATIONARY COMBUSTION TURBINES

Phase I (By date of promulgation or upon initial startup)	Phase II Beginning in 2032-2035	Phase III Beginning in 2038
Low Load Subcategory (Capacity Factor <20%)		
BSER: Use of low emitting fuels (e.g., natural gas and distillate oil) Standard: From 120 lb CO_2/MMBtu to 160 lb CO_2/MMBtu, depending on fuel type	No proposed Phase II or Phase III BSER component or standard of performance	
Intermediate Load Subcategory (Capacity Factor 20% to ~50%*) ***Upper bound limit based on EGU design efficiency and site-specific factors**		
BSER: Highly efficient simple cycle generation Standard: 1,150 lb CO_2/MWh-gross	**BSER:** Continued highly efficient simple cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 Standard: 1,000 lb CO_2/MWh-gross	No proposed Phase III BSER component or standard of performance
Base Load Subcategory (Capacity Factor >~50%*) *Limit		
BSER: Highly efficient combined cycle generation Standard: 770 lb CO_2/MWh-gross (EGUs with a base load rating of 2,000 MMBtu/h or more) Standard: 770 lb – 900 lb CO_2/MWh-gross (EGUs with a base load rating of less than 2,000 MMBtu/h)	**Low-GHG Hydrogen Pathway BSER:** Continued highly efficient combined cycle generation with 30% (by volume) low-GHG hydrogen co-firing beginning in 2032 Standard: 680 lb CO_2/MWh-gross **CCS Pathway BSER:** Continued highly efficient combined cycle generation with 90% CCS beginning in 2035 Standard: 90 lbCO_2/MWh gross	**Low-GHG Hydrogen Pathway BSER:** Co-firing 96% (by volume) low-GHG hydrogen beginning in 2038 Standard: 90 lb CO_2/MWh-gross **CCS Pathway:** No Phase III BSER component or standard of performance
The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kgCO_2e/kgH_2 overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).		

NSPS – STATIONARY COMBUSTION TURBINES

Proposing to update and establish more protective NSPS for GHG emissions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs that are based on highly efficient generating practices in addition to CCS or co-firing low-GHG hydrogen.

- **Applicability date:** Date the proposal publishes in the Federal Register

Three general subcategories of stationary combustion turbines

- Low load "peaking" turbines
- Intermediate load turbines
- Base load turbines

For each subcategory, EPA is proposing a distinct "best system of emission reduction" (BSER) and standard of performance based on its evaluation of the feasibility, emissions reductions, and cost-reasonableness of available controls.

NSPS – STATIONARY COMBUSTION TURBINES

Low load "peaking" combustion turbines BSER and standards:

BSER: lower emitting fuels (natural gas, distillate oil)

Standards of performance: 120 – 160 pounds of carbon dioxide per one million British thermal units (lb CO_2/MMBtu (depending on the fuel used)

Intermediate load combustion turbines:

BSER has two components to be implemented in 2 phases:

- 1st component of BSER: Highly efficient generation
- 2nd component of BSER: Co-firing 30% (by volume) low-GHG hydrogen

Phases:

- **1st phase standards**: 1,150 lb CO_2/MWh-gross – based on performance of a highly efficient natural gas-fired simple cycle turbine
- **2nd phase standards**: 1,000 lb CO_2/MWh-gross – based on performance of a highly efficient natural gas-fired simple cycle turbine co-firing 30% (by volume) low-GHG hydrogen by 2032
- Standards would be higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO_2/MMBtu basis

NSPS – STATIONARY COMBUSTION TURBINES

Base load combustion turbines:

Several components to be implemented in several phases:

- 1st component of BSER for all sources: Highly efficient generation
- 2nd component of BSER for sources on the CCS pathway: 90% carbon capture and storage (CCS) by 2035
- 2nd and 3rd components of BSER for sources on the low-GHG hydrogen pathway: co-firing 30% (by volume) low-GHG hydrogen by 2032 and 96% by 2038

<u>Phases:</u>

1st phase standards: 770 – 900 lb CO_2/MWh-gross, depending on the base load rating – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine. Standard is higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO_2/MMBtu basis.

2nd phase standards for base load units on the CCS pathway: 90 – 100 lb CO_2/MWh-gross, depending on the base load rating – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine implementing 90% CCS by 2035.

2nd phase standards for base load units on the low-GHG hydrogen pathway: 680 lb CO_2/MWh-gross – based on the performance of a highly efficient natural gas-fired combined cycle combustion turbine co-firing 30% (by volume) low-GHG hydrogen by 2032.

- Standard is higher for combustion turbines burning non-natural gas fuels with higher emission rates on a lb CO_2/MMBtu basis

3rd phase standards for base load units on the low-GHG hydrogen pathway, Phase 3 standards are based on 96% (by volume) low-GHG hydrogen by 2038.

LOW-GHG HYDROGEN

EPA included a proposed definition of low-GHG hydrogen to ensure co-firing achieves the maximum possible overall emissions reductions.

Low-GHG hydrogen is defined in this proposal as hydrogen produced with less than 0.45 kilograms of CO_2 equivalent overall emissions per kilogram of hydrogen ($kgCO_2$-e/kgH2) from from "well to gate" (meaning from input feedstock extraction to the exit gate of the hydrogen production facility).

This is consistent with Congress' definition of the lowest GHG hydrogen tier identified for the highest tax credits in the Inflation Reduction Act.

PROPOSED BSER LEVELS FOR 111D – EXISTING COAL, OIL AND NATURAL GAS-FIRED BOILERS AND LARGE, FREQUENTLY USED NATURAL GAS COMBUSTION TURBINES

Coal-Fired Boilers	Natural Gas and Oil-Fired Boilers	Natural Gas Combustion Turbines
For units operating past December 31, 2039, **BSER:** CCS with 90% capture of CO_2 an (88.4% reduction)	**BSER:** routine methods of operation and maintenance with an associated degree of emission limitation of no increase in emission rate (lb CO_2/MWh-gross).	For turbines >300MW, >50% capacity factor **CCS Pathway BSER:** By 2035: highly efficient generation coupled with CCS with 90% capture of CO_2 (90 lb CO_2/MWh) **Low-GHG Hydrogen Pathway BSER:** By 2032: highly efficient generation coupled with co-firing 30% (by volume) low-GHG hydrogen (680 lb CO_2/MWh) By 2038: highly efficient generation coupled with co-firing 96% low-GHG hydrogen (90 lb CO_2/MWh)
For units that cease operations before January 1, 2040 and are not in other subcategories, **BSER**: co-firing 40% (by volume) natural gas with emission limitation of a 16% reduction in emission rate (lb CO_2/MWh-gross basis)		
For units that cease operations before January 1, 2032, and units that cease operations after January 1, 2035, that adopt enforceable annual capacity factor limit of 20%, **BSER**: routine methods of operation and maintenance with associated degrees of emission limitation of no increase in emission rate		

The proposed definition of low-GHG hydrogen is hydrogen produced with less than 0.45kgCO_2e/kgH_2 overall well to gate emissions, consistent with IRC section 45V(b)(2)(D).

EMISSION GUIDELINES - EXISTING COMBUSTION TURBINES

EPA is proposing:

- Emission guidelines for large and frequently used existing stationary combustion turbines, which are larger than 300 MW with a capacity factor of greater than 50 percent.
- A BSER that is consistent with the second and third phases of the BSER for new base load combustion turbines.
- BSER for these units is based on either:
  - 90% capture of CO_2 using CCS by 2035; or
  - Co-firing of 30% by volume low-GHG hydrogen beginning in 2032 and co-firing 96% by volume low-GHG hydrogen beginning in 2038.
- Soliciting comment on how the Agency should approach its legal obligation to establish emission guidelines for the remaining existing fossil fuel-fired combustion turbines not covered by this proposal, including smaller frequently used existing fossil fuel-fired combustion turbine EGUs and less frequently used existing fossil fuel-fired combustion turbines.

EMISSION GUIDELINES — SUBCATEGORIES FOR COAL-FIRED STEAM GENERATING EGUS

Proposes four subcategories for **existing coal-fired steam generating EGUs**, based on the operating horizon of the unit:

- Long-term EGUs – Units that will operate in the long-term
- Medium-term EGUs – Units that elect to commit to permanently cease operations prior to January 1, 2040 and that are not near-term or imminent-term EGUs
- Near-term EGUs – Units that elect to commit to permanently cease operations prior to January 1, 2035, and commit to operate with an annual capacity factor limit of 20 percent
- Imminent-term EGUs – Units that elect to commit to permanently cease operations prior to January 1, 2032

EMISSION GUIDELINES — BSER AND DEGREE OF EMISSION LIMITATION

Long-term Coal-fired Steam Generating Units

- BSER: Carbon capture and storage with 90% CO_2 capture by 2030
- Emission limitation: 88.4% reduction in emission rate

Medium-term Coal-fired Steam Generating Units

- BSER: co-firing 40% (by heat input) natural gas by 2030
- Emission limitation: 16% reduction in emission rate

Imminent-term and Near-term Coal-fired Steam Generating Units

- BSER: Routine methods of operation and maintenance
- Emission limitation: no increase in emission rate (presumptive standard of a unit-specific baseline)

Natural gas- and oil-fired steam generating units

- BSER: Routine methods of operation and maintenance
- Emission limitation: no increase in emission rate (in general, fixed presumptive standards for intermediate load and base load units)

ADDITIONAL AREAS OF COMMENT

- Soliciting comment on:
  - Variations to the subcategories and BSER determinations, as well as the associated degrees of emission limitation and standards of performance.
  - BSER options and associated degrees of emission limitation for existing fossil fuel-fired stationary combustion turbines for which no BSER is being proposed (i.e., fossil fuel-fired stationary combustion turbines that are not large, frequently operated turbines).

STATE PLANS FOR PROPOSED EMISSION GUIDELINES

Under section 111(d) of the Clean Air Act, states must submit plans to EPA that provide for the establishment, implementation and enforcement of standards of performance for existing sources.

- State plans must generally establish standards that are at least as stringent as EPA's emission guidelines.
- States may take into account remaining useful life and other factors when applying standards of performance to individual existing sources.

General implementing regulations for emission guidelines under CAA section 111

- EPA proposed revisions to the implementation regulations (40 CFR part 60, subpart Ba) in December 2022 that, if finalized, would also apply to these emission guidelines.
- The comment period closed February 27, 2023.
- More information: https://www.epa.gov/stationary-sources-air-pollution/adoption-and-submittal-state-plans-designated-facilities-40-cfr

STATE PLANS FOR PROPOSED EMISSION GUIDELINES

State Plan Submission Deadline

- Proposing submission within 24 months of the effective date of the emission guidelines

State Plan Components

- Proposing requirements specific to these emission guidelines to ensure transparency, including a website hosted by EGU owners/operators to publish documentation and information related to compliance with the state plan

Compliance Deadlines

- Existing steam generating units: January 1, 2030
- Existing combustion turbine units: January 1, 2032, or January 1, 2035, depending on their subcategory

Meaningful Engagement

- Proposing to require states to undertake meaningful engagement with pertinent stakeholders, including communities that are most affected by and vulnerable to emissions from these EGUs
- Ensures that the priorities, concerns and perspectives of these communities are heard during the planning process.

STATE PLANS FOR PROPOSED EMISSION GUIDELINES

Establishing Standards of Performance

- Proposing a presumptively approvable methodology (or standard, where applicable); states apply EPA's degree of emission limitation to a baseline emission rate for an affected EGU
  - Baseline: lb CO_2/MWh-gross from any continuous 8-quarter period within the 5 years immediately prior to the date the final rule is published in the *Federal Register*
- Proposing increments of progress for certain subcategories, as well as requirements to report milestones related to ceasing operations for units that elect to commit to doing so (medium, near, and imminent-term coal-fired subcategories)

Compliance Flexibilities

- Proposing to allow trading and averaging for state plans under these emission guidelines
  - States would not be required to allow for such compliance mechanisms in their state plans, but could elect to include them
- Taking comment on what limitations or requirements should apply to ensure that trading and averaging mechanisms achieve equivalent stringency to each source individually achieving its standard of performance

Remaining Useful Life and Other Factors (RULOF)

- States would apply EPA's framework for applying less stringent standards based on a particular facility's remaining useful life or other factors. To receive a less stringent standard, a state must demonstrate that a facility cannot reasonably achieve the stringency achievable through application of the BSER.

REPEAL OF THE AFFORDABLE CLEAN ENERGY (ACE) RULE

- EPA is simultaneously proposing to repeal the Affordable Clean Energy (ACE) rule because the emission guidelines established in ACE do not reflect the BSER for steam generating EGUs and are inconsistent with section 111 of the CAA in other respects.

EMISSIONS CHANGES, BENEFITS, AND COSTS

- EPA estimated the national emissions changes, benefits and costs in a Regulatory Impact Analysis (RIA). The RIA presents information about the NSPS for new gas turbines and the emission guidelines for existing coal units together.
    - Provides estimates of the emission changes associated with the existing source gas proposal and the third phase of the NSPS for new gas turbines.
- Estimates are presented two ways – as present values (PV) and equivalent annualized values (EAV). The PV is the costs or benefits over the 19-year period of 2024 to 2042. The EAV represents the value for each year of the analysis.

EMISSIONS CHANGES, BENEFITS, AND COSTS

Emissions Changes

- Aggregate emission cuts from 2028-2042
  - Proposals would cut **617 million metric tons of CO_2** through 2042 along with tens of thousands of tons of PM2.5, SO2, and NOx – harmful air pollutants that are known to endanger public health.
  - Estimates do not include the impact of the proposed requirements for existing gas-fired combustion turbines. A separate EPA analysis of these proposed requirements estimates they would reduce between **214 and 407 million metric tons of CO_2** cumulatively between 2028 and 2042.

- Annual emissions changes

  For the NSPS for new gas turbines and emission guidelines for existing coal units
  - In 2030, the power sector would emit:
    - 89 million metric tons less CO2
    - 64,000 tons less annual NOx
    - 22,000 tons less ozone season NOx
    - 107,000 tons less SO2
    - 6,000 tons less direct PM2.5

EMISSIONS CHANGES, BENEFITS, AND COSTS

Net Benefits

For the NSPS for new gas turbines and emission guidelines for existing coal units

- Present value (2024-2042) - $64 billion-$85 billion
- Equivalent annual value (single year) - $5.4 billion to $5.9 billion

Health Benefits

For the NSPS for new gas turbines and emission guidelines for existing coal units

- Estimated health benefits in 2030 would be at least $6.5 billion and could be as much as $14 billion (2019$, 3% discount rate).

- In 2030 alone, the health benefits include:
  - Approximately 1,300 avoided premature deaths;
  - More than 800 avoided hospital and emergency room visits;
  - Approximately 2,000 avoided cases of asthma onset and 300,000+ avoided cases of asthma symptoms; and
  - 38,000 avoided school absence days and more than 66,000 lost work days

EMISSIONS CHANGES, BENEFITS, AND COSTS

For the NSPS for new gas turbines and emission guidelines for existing coal units

	2028	2030	2035	2040
Climate Benefit	$0.60 billion	$5.4 billion	$2.5 billion	$1.7 billion
PM2.5 and O3-related Health Benefits	$0.68 billion to $1.6 billion	$6.5 billion to $14 billion	$2.2 billion to $4.7 billion	$1.8 billion to $3.6 billion
Total Benefits	$1.3 billion to $2.2 billion	$12 billion to $20 billion	$4.6 billion to $7.1 billion	$3.5 billion to $5.3 billion
Costs	-$0.21 billion	$4.1 billion	$0.28 billion	$0.76 billion
Net Benefits	$1.5 billion to $2.4 billion	$7.8 billion to $16 billion	$4.4 billion to $6.8 billion	$2.7 billion to $4.5 billion

ENVIRONMENTAL JUSTICE ASSESSMENT

In conjunction with other policies such as the Inflation Reduction Act, these proposals will play a significant role in reducing GHGs and move us a step closer to avoiding the worst impacts of climate change, which is already having a disproportionate impact on EJ communities.

These proposals include an environmental justice analysis that quantitatively evaluates:

- the proximity of affected facilities to potentially vulnerable and/or overburdened populations for consideration of local pollutants impacted by these proposals and
- the distribution of ozone and PM2.5 concentrations in the baseline and changes due to the proposed rulemakings across different demographic groups on the basis of race, ethnicity, poverty status, employment status, health insurance status, age, sex, educational attainment, and degree of linguistic isolation.

The environmental justice assessment also includes discussions of climate impacts across various demographic groups.

Overall, the EJ analysis of ozone and PM2.5 concentration changes due to the proposed rulemakings indicates that the air quality benefits of these proposals in three of the four future years would lead to similar reductions in exposures across all demographic groups.

MEANINGFUL ENGAGEMENT

- Proposed emission guidelines would require states to undertake meaningful engagement with affected stakeholders
- With regard to CCS, EPA is proposing that CCS is a component of the BSER for new base load stationary combustion turbine EGUs, existing coal-fired steam generating units that intend to operate after 2040, and large and frequently operated existing stationary combustion turbine EGUs.
- EPA recognizes and has given careful consideration to the various concerns that potentially vulnerable communities have raised with regard to the use of CCS.
- EPA and our fellow federal agencies are committed to responsible and safe deployment of CCS and there is a robust existing regulatory framework to ensure that. Deployment of CCS should take place in a manner that is protective of public health, safety, and the environment, and that includes early and meaningful engagement with affected communities and the public.

COMMUNITY AND TRIBAL WEBINARS

- To help engage with environmental justice communities, tribal nations, and tribal environmental professionals on the proposed rule, EPA will hold two informational webinars.

- These webinars will provide an overview of the proposed rule, information on how to effectively engage in the regulatory process, and an opportunity to participate in a Q&A session.

- These virtual events are free and open to the public and will be held on **June 6th and June 7th**. Further details, including how to register for the webinars will be provided on EPA's website at https://www.epa.gov/stationary-sources-air-pollution/greenhouse-gas-standards-and-guidelines-fossil-fuel-fired-power

PUBLIC HEARING AND COMMENT

- EPA will hold a virtual public hearing for this proposed action. Further details will be announced at Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants.
- EPA will accept comment on the proposal for 60 days after publication in the Federal Register. Comments, identified by Docket ID No. EPA-HQ-OAR-2023-0072, may be submitted by one of the following methods:
  - Go to https://www.regulations.gov/ and follow the online instructions for submitting comments.
  - Send comments by email to a-and-r-docket@epa.gov, Attention Docket ID No. EPA-HQ-OAR-2023-0072 in the subject line of the message.
  - Fax your comments to: (202) 566-9744, Attention Docket ID No. EPA-HQ-OAR-2023-0072.
  - Mail your comments to: EPA Docket Center, Environmental Protection Agency, Mail Code: 28221T, 1200 Pennsylvania Ave, NW, Washington, DC 20460, Attention Docket ID No. EPA-HQ-OAR-2023-0072.
  - Deliver comments in person to: EPA Docket Center, 1301 Constitution Ave., NW, Room 3334, Washington, DC. Note: In-person deliveries (including courier deliveries) are only accepted during the Docket Center's normal hours of operation. Special arrangements should be made for deliveries of boxed information.

FOR MORE INFORMATION

- Interested parties can download a copy of the proposed rule from Greenhouse Gas Standards and Guidelines for Fossil Fuel-Fired Power Plants
- The proposed rule and other background information will also be available electronically at https://www.regulations.gov/, EPA's electronic public docket and comment system.
  - After publication, materials for this proposed action can be accessed using Docket ID No. EPA-HQ-OAR-2023-0072.

THANK YOU

June 5, 2023

Representative Bill Johnson
Chairman, Environment, Manufacturing & Critical Materials Subcommittee
U.S. House of Representatives
Washington DC 20515

Representative Paul Tonko
Ranking Member, Environment, Manufacturing & Critical Materials Subcommittee
U.S. House of Representatives
Washington DC 20515

Dear Chairman Johnson and Ranking Member Tonko:

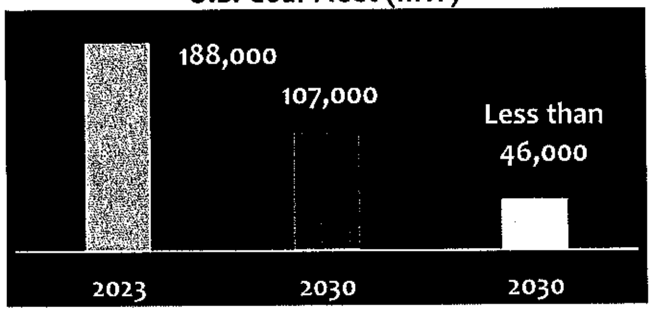
In light of tomorrow's subcommittee hearing "Clean Power Plan 2.0: EPA's Latest Attack On America's Electric Reliability," I am writing to provide our brief perspective on U.S EPA's proposed CPP 2.0.

America's Power advocates for coal electricity and its supply chain. Coal plants provide affordable baseload electricity, secure fuel supplies, essential reliability services, other reliability attributes, and they contribute to energy diversity. However, EPA is implementing, has finalized, or has proposed five rules that will force more coal retirements and increase the risk of electricity shortages and other grid reliability problems.

EPA has been slowly implementing its revised Coal Combustion Residuals (CCR) Rule; finalized its Good Neighbor Rule (GNR); and proposed revised Effluent Limitations Guidelines (ELG), revised Mercury and Air Toxics Standards (MATS), and CPP 2.0. We estimate that these EPA rules collectively will cause coal retirements to rise sharply during 2026-2030 and exacerbate the risk of grid reliability problems. For example, EPA estimates that the GNR will cause the retirement of 14,000 MW of coal by 2030, and the CCR and ELG rules include explicit incentives for coal plants to retire by 2028.

The coal fleet totals 188,000 megawatts (MW), a sharp decline of 127,000 MW since 2010. By 2030, the coal fleet would total 107,000 MW if only coal retirements announced so far are taken into account (orange bar below). However, EPA projects that the coal fleet will total only 46,000 MW by 2030 (yellow bar) because of the Inflation Reduction Act and four EPA rules, including CPP 2.0. The 46,000 MW projected by EPA do not account for impacts from the agency's recently proposed MATS rule or the Regional Haze Rule that EPA has been slow to implement. EPA's projections, which we believe still understate future coal retirements, show that the nation's coal fleet will be dangerously small by 2030, possibly earlier.

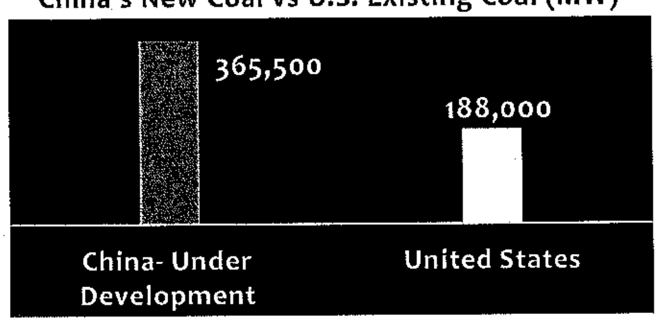
U.S. Coal Fleet (MW)



CCP 2.0 is arguably the worst of these EPA rules and is intended to replace the original Clean Power Plan which was rejected by the U.S. Supreme Court as an overreach. CPP 2.0 is also an overreach. The proposal would have an unprecedented impact on the coal fleet, which must comply with the proposal by January 1, 2030. This means the owners of the coal fleet would have less than three years to comply because states have two years (until mid-2026) to submit plans to EPA after the rule is finalized, and the agency has one year (until mid-2027) to approve (or disapprove) state plans. Compliance could entail co-firing with 40% natural gas or installation of carbon capture and storage (CCS). CCS takes nine years or more to install and can cost $1 billion for an average coal plant. The ridiculous compliance deadline and the enormous cost of compliance simply mean more premature coal retirements and greater odds of electricity shortages. Because of the proposed carbon rule, we estimate that more than 100,000 MW of coal nationwide are at risk of even earlier retirement than is reflected in retirement projections by EPA.

CPP 2.0 is intended to help decarbonize the U.S electric grid and presumably reduce the effects of climate change. However, the proposal would reduce global greenhouse gas emissions by one-tenth of a percent. Moreover, China continues to aggressively expand its own coal fleet while EPA and the administration are attempting to eliminate the U.S. coal fleet. Currently, China's coal fleet is roughly the same size (more than 1 million MW) as the entire U.S. electricity supply (more than 1 million MW). Moreover, China has announced or has under development almost 366,000 MW of coal-fired generating capacity. This means that the entire U.S. coal fleet (188,000 MW), which the administration is attempting to eliminate, is only half the size of the *new* coal-fired generating capacity that China is adding to its already enormous coal fleet.

China's New Coal vs U.S. Existing Coal (MW)



As PJM's President and CEO testified recently, "Currently, the nation is developing environmental and reliability policy in separate silos with limited and not very transparent coordination between the environmental and reliability regulators. Increased coordination and synchronization of the nation's environmental and reliability needs may require discrete changes to the statutes governing each agency's mission to embrace this effort." Congress can play a critical role though both oversight and new legislation to remedy this lack of coordination.

Sincerely,

Michelle A. Bloodworth

Michelle Bloodworth
President and CEO

Copy to:

Representative Cathy McMorris Rogers
Chair, Energy and Commerce Committee

Representative Frank Pallone
Ranking Member, Energy and Commerce Committee

Energy Transition in PJM:
Resource Retirements, Replacements & Risks

Feb. 24, 2023

For Public Use

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Contents

Executive Summary

Driven by industry trends and their associated challenges, PJM developed the following strategic pillars to ensure an efficient and reliable energy transition: facilitating decarbonization policies reliably and cost-effectively; planning/operating the grid of the future; and fostering innovation.

PJM is committed to these strategic pillars, and has undertaken multiple initiatives in coordination with our stakeholders and state and federal governments to further this strategy, including interconnection queue reform, deployment of the State Agreement Approach to facilitate 7,500 MW offshore wind in New Jersey, and coordination with state and federal governments on maintaining system reliability while developing and implementing their specific energy policies.

In light of these trends and in support of these strategic objectives, PJM is continuing a multiphase effort to study the potential impacts of the energy transition. The first two phases of the study focused on energy and ancillary services and resource adequacy in 2035 and beyond. This third phase focuses on resource adequacy in the near term through 2030.[1]

Maintaining an adequate level of generation resources, with the right operational and physical characteristics[2], is essential for PJM's ability to serve electrical demand through the energy transition.

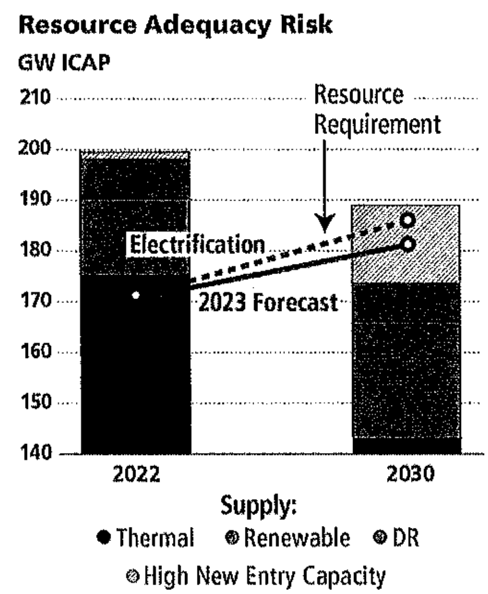
Our research highlights four trends below that we believe, in combination, present increasing reliability risks during the transition, due to a potential timing mismatch between resource retirements, load growth and the pace of new generation entry under a possible "low new entry" scenario:

- The growth rate of electricity demand is likely to continue to increase from electrification coupled with the proliferation of high-demand data centers in the region.
- Thermal generators are retiring at a rapid pace due to government and private sector policies as well as economics.
- Retirements are at risk of outpacing the construction of new resources, due to a combination of industry forces, including siting and supply chain, whose long-term impacts are not fully known.
- PJM's interconnection queue is composed primarily of intermittent and limited-duration resources. Given the operating characteristics of these resources, we need multiple megawatts of these resources to replace 1 MW of thermal generation.

[1] See Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid | Addendum (2022).

[2] See previous work on Reliability Products and Services, including PJM's Evolving Resource Mix and System Reliability (2017), Reliability in PJM: Today and Tomorrow (2021), Energy Transition in PJM: Frameworks for Analysis | Addendum (2021), and work completed through the RASTF and PJM Operating Committee (2022).

The analysis also considers a "high new entry" scenario, where this timing mismatch is avoided. While this is certainly a potential outcome, given the significant policy support for new renewable resources, our analysis of these long-term trends reinforces the importance of PJM's ongoing stakeholder initiatives, including capacity market modifications, interconnection process reform and clean capacity procurement, and the urgency for continued, combined actions to de-risk the future of resource adequacy while striving to facilitate the energy policies in the PJM footprint.



The projections in this study indicate that it is possible that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030.

The first two phases of the energy transition study assumed that PJM had adequate resources to meet load.

In this this third phase of this living study, we explore a range of plausible scenarios up to the year 2030, focusing on the resource mix "balance sheet" as defined by generation retirements, demand growth and entry of new generation.

The analysis shows that 40 GW of existing generation are at risk of retirement by 2030. This figure is composed of: 6 GW of 2022 deactivations, 6 GW of announced retirements, 25 GW of potential policy-driven retirements and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity[3].

In addition to the retirements, PJM's long-term load forecast shows demand growth of 1.4% per year for the PJM footprint over the next 10 years. Due to the expansion of highly concentrated clusters of data centers, combined with overall electrification, certain individual zones exhibit more significant demand growth – as high as 7% annually.[4]

On the other side of the balance sheet, PJM's New Services Queue consists primarily of renewables (94%) and gas (6%). Despite the sizable nameplate capacity of renewables in the interconnection queue (290 GW), the historical rate of completion for renewable projects has been approximately 5%. The projections in this study indicate that the current pace of new entry would be insufficient to keep up with expected retirements and demand growth by 2030. The completion rate (from queue to steel in the ground) would have to increase significantly to maintain required reserve margins.

In the study, we also consider generation entry beyond the queue using projections from S&P Global. Those projections indicate that, despite eroding reserve margins, resource adequacy would be maintained if the influx of renewables materializes at a rapid rate and gas remains the transition fuel, adding 9 GW of capacity. The analysis performed at the Clean Attribute Procurement Senior Task Force (CAPSTF) also suggests that further gas expansion is economic and competitive.[5]

[3] Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.
[4] PJM Load Forecast Report, January 2023.
[5] CAPSTF Analysis, Initial Results; Emmanuele Bobbio, Sr. Lead Economist – Advanced Analytics, PJM, Dec. 16, 2022.

Balance Sheet Summary (2022–2030)				
Retirements **40 GW** **60% Coal** **30% Natural Gas** **10% Other**	**New Entry Wind/Solar**[6] **Low =** 48 GW-nameplate / 8 GW-capacity **High =** 94 GW-nameplate / 17 GW-capacity	**New Entry Standalone Storage** **Low =** 3 GW **High =** 4 GW	**New Entry Thermal** **Low =** 4 GW **High =** 9 GW	**Load Growth** **2023 Forecast =** 11 GW **Electrification Forecast =** 13 GW
Unless otherwise noted, thermal capacity values are expressed in ICAP, without adjustment for EFORd.				

For the first time in recent history, PJM could face decreasing reserve margins should these trends continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources and demand response, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, Clean Attribute Procurement Senior Task Force, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy. The potential for an asymmetrical pace in the energy transition, in which resource retirements and load growth exceed the pace of new entry, underscores the need to enhance the accreditation, qualification and performance requirements of capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain reliability. It is critical that all PJM markets effectively correct imbalances brought on by retirements or load growth by incentivizing investment in new or expanded resources.

[6] Includes hybrid projects with battery storage

Background

Resource adequacy is the ability of the electric system to supply the aggregate energy requirements of electricity to consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of generation and transmission facilities. To achieve the goal of resource adequacy, PJM maintains an Installed Reserve Margin in excess of the forecast peak load that achieves a loss-of-load expectation (LOLE) of one day in 10 years. This LOLE standard is consistent with that prescribed in the ReliabilityFirst Corporation standard for planning resource adequacy.[7]

Long-term reliability and resource adequacy are addressed through the combined operation of PJM's electricity markets, and in particular the capacity market, called the Reliability Pricing Model (RPM). Each PJM member that provides electricity to consumers must acquire enough power supply to meet demand, not only for today and tomorrow, but for the future. Members secure these capacity resources for future energy needs through a series of base and incremental capacity auctions, as well as Fixed Resource Requirement plans.

The capacity market ensures long-term grid reliability by procuring the appropriate amount of power supply resources needed to meet predicted energy demand up to three years in the future. These capacity resources have an obligation to perform during system emergencies, and are subject to penalties if they underperform. By matching generation with future demand, the capacity market creates long-term price signals to attract needed investments to ensure adequate power supplies. This exchange provides consumers with an assurance of reliable power in the future, while capacity resources receive a dependable flow of income to help maintain their existing capability, attract investment in new resources, and encourage companies to develop new technologies and sources of electric power.

Methodology

The size, composition and performance characteristics of the resource mix will determine PJM's ability to maintain reliability. This study explores a range of scenarios in the context of resource adequacy, focusing on the resource mix "balance sheet" as defined by demand growth, generation retirements and new entry of generation. Using the methodology described in this section, PJM evaluates the future of resource adequacy by estimating the amount of capacity required to cover load expectations versus expected capacity for the years 2023 through 2030.

The study's initial supply levels are 192.3 GW of installed capacity from generation resources and 7.8 GW of installed capacity from demand response capacity resources. The generation mix is approximately 178.9 GW of thermal resources and 13.3 GW of renewables and storage.[8]

[7] RFC Standard BAL-502-RF-03: Planning Resource Adequacy Analysis, Assessment and Documentation

[8] This value includes the capacity value of run-of-river hydro, pumped storage hydro, solar, onshore wind, offshore wind and battery energy storage.

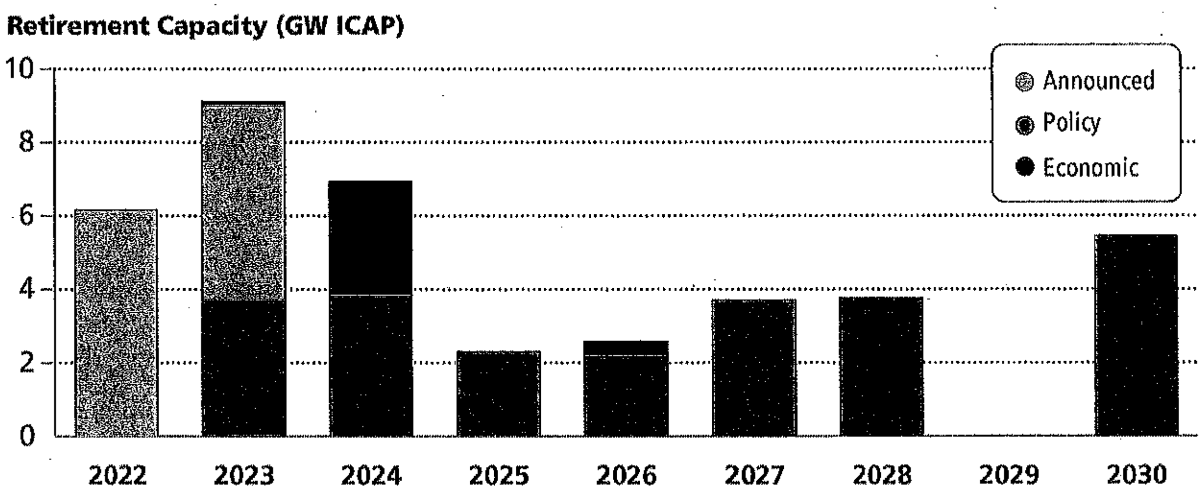
Supply Exits

PJM is undergoing a major transition in the resources needed to maintain bulk power grid reliability.

Historically, thermal resources have provided the majority of the reliability services in PJM. Today, a confluence of conditions, including state and federal policy requirements, industry and corporate goals requiring clean energy, reduced costs and/or subsidies for clean resources, stringent environmental standards, age-related maintenance costs, and diminished energy revenues are hastening the decline in thermal resources.

This study estimates anticipated retirements through 2030 by adding announced retirements with retirements likely as a result of various state and federal policies, and then with those at risk for retirement due to deteriorating unit economics. Potential policy-driven retirements, in this context, reflect resources that are subject to current and proposed federal and state environmental policies, in which it is conservatively assumed that the costs of mitigation and compliance could economically disadvantage these resources to the point of retirement. **Figure 1** highlights the 40 GW of projected generation retirements by 2030, which is composed of: 12 GW of announced retirements[9], 25 GW of potential policy-driven retirements[10] and 3 GW of potential economic retirements. Combined, this represents 21% of PJM's current installed capacity.[11] This section describes each category of potential retirements in more detail.

Figure 1. Total Forecast Retirement by Year (2022–2030)



[9] Includes 6 GW of 2022 retirements.

[10] Note that 7 GW of the 25 GW of supply with policy risk was also identified to have more immediate economic risk. The year that these 7 GW of potential policy retirements shown in **Figure 2** is based on timing identified in the economic analysis. In **Figure 4**, these 7 GW are shown in terms of the regulatory compliance timeline alone. The timeline of these potential quantities of resource retirements does not factor in any reliability "off-ramps" that may be included in established policies.

[11] In this study, PJM assumes that a resource that exits would not return to service in a future delivery year, even if operational conditions improve. Historically, a small percentage of retiring units would instead enter a "mothball" or standby state, in which the unit is put into a state where it may not operate for one or more years; however, in order to obtain an operating permit renewal, the mothballed unit would have to comply with the most recent environmental standards, likely requiring costly upgrades, making investing in newer, cleaner technologies more inviting.

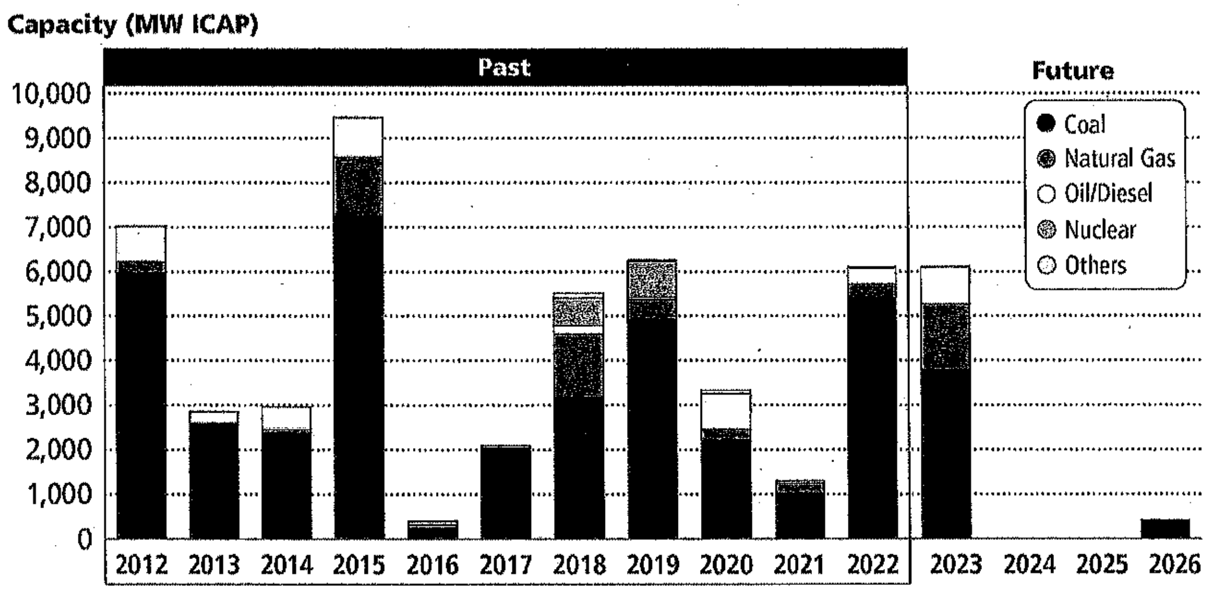
Announced Retirements

One of PJM's responsibilities is to ensure the continued reliability of the high-voltage electric transmission system when a generation owner requests deactivation. Through its Generation Deactivation process,[12] PJM identifies transmission solutions that allow owners to retire generating plants as requested without threatening reliable power supplies to customers. PJM may order transmission upgrades or additions built by transmission owners to accommodate the generation loss. PJM has no authority to order plants to continue operating. However, in some instances, to maintain reliability, PJM may formally request that a plant owner continue operating, subject to rates authorized by the Federal Energy Regulatory Commission (FERC), while transmission upgrades are completed.

Plant owners considering retirement must notify PJM at least two quarters before the proposed deactivation date. PJM and the transmission owners complete a reliability analysis in the subsequent quarter after notification to PJM. Generator retirements and any required system upgrades to keep the grid running smoothly are included in the PJM Regional Transmission Expansion Planning process and are reviewed with PJM members and stakeholders at the PJM Transmission Expansion Advisory Committee.

Between 2012 and 2022, 47.2 GW of generation retired in PJM, as detailed by fuel type in **Figure 2**. In 2022, approximately 6 GW of generation deactivated and an additional 5.8 GW announced ("future") deactivations over the 2023–2026 time frame. The deactivations are slightly above the 10-year average of 4.3 GW, but well under the historical annual peak of 9.5 GW in 2015. Coal-fired resources account for approximately 89% of retired capacity in 2022.

Figure 2. Past and Announced Future Retirements



[12] See process details in PJM Manual 14-D, Section 9, and tracking of deactivation requests at https://www.pjm.com/planning/services-requests/gen-deactivations.

Potential Policy Retirements

An analysis of federal and state policies and regulations with direct impacts on generation in the PJM region yielded the largest group of potential future retirements in this study.[13] As highlighted in **Figure 3**, the combined requirements of these regulations and their coincident compliance periods have the potential to result in a significant amount of generation retirements within a condensed time frame. These impacts will be reevaluated as these policies and regulations evolve. PJM will continue to work with both federal and state agencies on the development and implementation of environmental regulations and policies in order to address any reliability concerns.

Below are the policies and regulations included in the study:

EPA Coal Combustion Residuals (CCR): The U.S. Environmental Protection Agency (EPA) promulgated national minimum criteria for existing and new coal combustion residuals (CCR) landfills and existing and new CCR surface impoundments. This led to a number of facilities, approximately 2,700 MW in capacity, indicating their intent to comply with the rule by ceasing coal-firing operations, which is reflected in this study.

EPA Effluent Limitation Guidelines (ELG): The EPA updated these guidelines in 2020, which triggered the announcement by Keystone and Conemaugh facilities (about 3,400 MW) to retire their coal units by the end of 2028.[14] Importantly, but not included in this study, the EPA is planning to propose a rule to strengthen and possibly broaden the guidelines applicable to waste (in particular water) discharges from steam electric generating units. The EPA is expecting this to impact coal units by potentially requiring investments when plants renew their discharge permits, and extending the time that plants can operate if they agree to a retirement date.

EPA Good Neighbor Rule (GNR): This proposal requires units in certain states to meet stringent limits on emissions of nitrogen oxides (NOx), which, for certain units, will require investment in selective catalytic reduction to reduce NOx. For purposes of this study, it is assumed that unit owners will not make that investment and will retire approximately 4,400 MW of units instead. Please note that the EPA plans on finalizing the GNR in March, which may necessitate reevaluation of this assumption.

Illinois Climate & Equitable Jobs Act (CEJA): CEJA mandates the scheduled phase-out of coal and natural gas generation by specified target dates: January 2030, 2035, 2040 and 2045. To understand CEJA criteria impacts and establish the timing of affected generation units' expected deactivation, PJM analyzed each generating unit's publically available emissions data, published heat rate, and proximity to Illinois environmental justice communities and Restore, Reinvest, Renew (R3) zones. For this study, PJM focuses on the approximately 5,800 MW expected to retire in 2030.

[13] Policies impacting forward energy prices, such as the Regional Greenhouse Gas Initiative and Renewable Energy Credits, are implicitly included in economic analysis but are not explicitly included in analysis of policy-related retirements.

[14] See State Impact PA, Nov. 22, 2021. These facilities have not filed formal Deactivation Notices with PJM.

New Jersey Department of Environmental Protection CO_2 Rule: New Jersey's CO_2 rule seeks to reduce carbon dioxide (CO_2) emissions of fossil fuel-fired electric generating units (EGUs) through the application of emissions limits for existing and new facilities greater than 25 MW. Units must meet a CO_2 output-based limit by tiered start dates. The dates and CO_2 limits are:

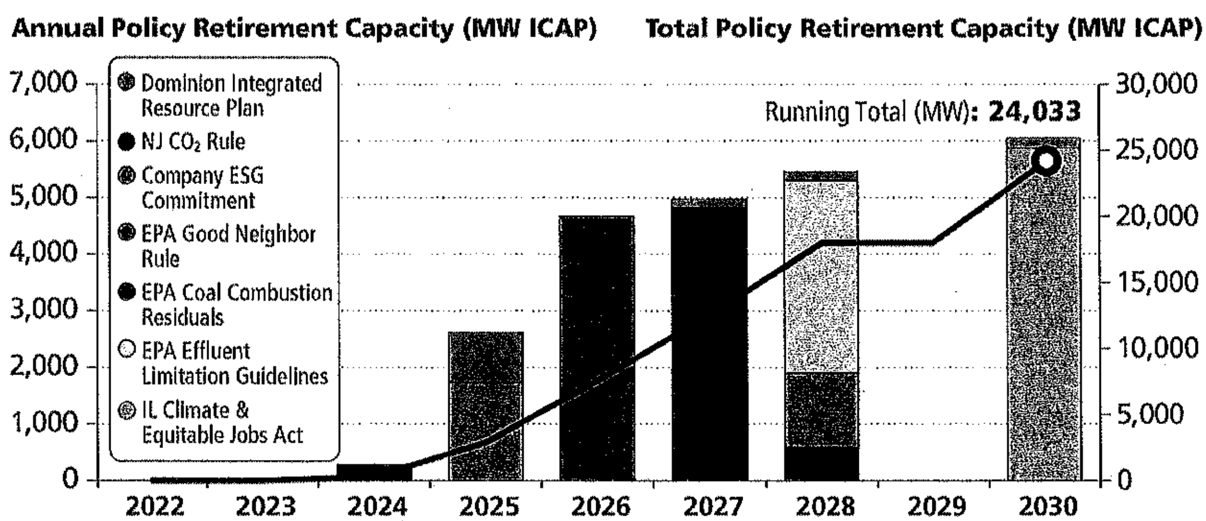
- June 1, 2024 – 1,700 lb/MWh
- June 1, 2027 – 1,300 lb/MWh
- June 1, 2035 – 1,000 lb/MWh

PJM used emissions data found in EPA Clean Air Markets Program Data to evaluate unit compliance. Where a unit's average annual emissions rate was greater than the CO_2 limit on the compliance date, the unit was assumed to be retiring. In this study PJM, estimated retirements at approximately 400 MW in 2024 and approximately 2,700 MW in 2027.

Dominion Integrated Resource Plan (IRP) commits to net zero carbon in its Virginia and North Carolina territory by 2050. PJM studied Dominion's Alternative Plan B retirement schedule, approximately 1,533 MW, for this analysis. Alternative Plan B proposes "significant development of solar, wind and energy storage resource envisioned by the VCEA," (Virginia Clean Economy Act of 2020), while maintaining natural gas generation for reliability, which is reflected in our analysis.

Company ESG (Environmental, Social, Governance) commitments are included where there is a commitment to retire resources per legal consent decree or other public statement. This includes the elimination of coal use and the retirement of the Brandon Shores, 1,273 MW, and Wagner, 305 MW, facilities in Maryland and the retirement of Rockport, 1,318 MW, in Indiana.

Figure 3. Potential Policy Retirements



Potential Economic Retirements

The third category of retirements in this study, beyond those formally announced and made likely by policy implementation, were identified through an analysis of revenue adequacy, the ability to economically cover going-forward costs from the wholesale markets. A net profit value was calculated for each existing generation resource using an estimate of future revenues and historical costs.

$$Net\ Profit = (\ Gross\ Energy\ \&\ Ancillary\ Service\ Revenue - Production\ Costs\ ) \\ + (\ Capacity\ Revenue\ ) - (\ Fixed\ Avoidable\ Costs\ )$$

The results reveal that a portion of the thermal fleet is at risk of becoming unprofitable in the coming years.

The capacity market's Variable Resource Requirement (VRR) represents the set of prices for which load is willing to procure additional supply beyond the minimum reliability requirement. There are three points in the sloped demand curve, the first of which is anchored at a price 1.5 times the Net Cost of New Entry (Net CONE). Should the auction clear at this price level, the auction result signals that demand is willing to pay for the construction of new supply, minus the expected energy revenues the resource should expect to earn in the energy markets. As such, it is important to align the revenue expectations for the marginal resources with forward revenues, especially under PJM's continually changing landscape of business rules.

Energy & Ancillary Services Revenue and Production Cost

This study used a scaling approach to estimate forward unit-specific energy and ancillary services (E&AS) revenues from historical energy and ancillary service revenues by applying the following:

$$Fwd\ Unit\ E\&AS\ Revenue = Hist\ Unit\ E\&AS\ Revenue * \frac{Fwd\ Reference\ E\&AS\ Revenue^{15}}{Hist\ Reference\ E\&AS\ Revenue} * \frac{Reference\ Avg\ Heat\ Rate}{Unit\ Avg\ Heat\ Rate}$$

For a given reference resource type, unit dispatch was simulated using both historical and forward energy hub-adjusted energy prices. For the equivalent production cost model, the relative ratio of revenues and heat rates indicate the net effects of both rising fuel costs and energy price revenue. A unit on the margin in the energy markets, typically a natural gas unit, would set a locational price near its short-run marginal costs. Infra-marginal units, potentially coal units, would receive higher revenues as price-taking resources, and thus may see increased profitability. This is reflected in the analysis, in which a reference coal unit's forward revenues increased an average of 139% over previous revenue estimates.

[15] The forward energy and ancillary services revenue calculation used in this study is the method that was developed for use in the Forward Net Energy & Ancillary Services Offset calculation originally developed in 2020, and filed as part of the most recent Quadrennial Review.

Capacity Revenues and Fixed Avoidable Costs

Unit-specific capacity revenues were calculated from prices and cleared quantities in the 2023/2024 Base Residual Auction (BRA). The study used the published 2023/2024 BRA Default Gross Avoidable Cost Rate (ACR) values as representative total fixed costs ($/MW-day) required to keep the generating plant available to produce energy. In other words, these are projected costs that could be avoided by the retirement of the plant. Avoidable costs represent operational factors like operations and maintenance labor, fuel storage costs, taxes and fees, carrying charges, and other costs not directly related to the production of energy. When available, unit-specific ACR values from the 2023/2024 BRA supply offer mitigation process were used, otherwise the class average Gross ACR was used.

Results and Estimated Impact

This study assumes that a simulated economic loss would result in a retirement of the resource at the next available delivery year in which the unit is not committed for capacity. As such, a unit with a revenue loss that did not clear in the 2023/2024 BRA would exit in 2023, while a unit with a revenue loss that cleared in the 2023/2024 BRA would exit in 2024. While units that do not clear a single BRA may remain energy-only resources, this conservative assumption was used to provide awareness.

The economic analysis identified approximately 10 GW of supply in immediate economic risk, of which 7 GW of supply is also affected by policy risk, and 3 GW of supply is economic risk only. In aggregate, 6 GW are steam resources, and 4 GW represent combustion turbines and internal combustion resources. Several of the units identified were older steam boilers that had once converted from coal-fired to natural gas fuel; these resources are less efficient than a modern heat-recovery steam generator in a combined cycle unit. Fifty-three percent of the resources identified for economic risk did not have a PJM capacity obligation in Delivery Year 2023/2024, either through the FRR process or market clearing.

Supply Entry

The composition of the PJM Interconnection Queue has evolved significantly in recent years, primarily increasing in the amount of renewables, storage, and hybrid resources and decreasing in the amount of natural gas-fired resources entering the queue. The PJM New Services Queue stands at approximately 290 ICAP GW of generation interconnection requests, of which almost 94% (271 ICAP GW) is composed of renewable and storage-hybrid resources.

Natural Gas Headwinds

In the last decade, resources in the PJM region have benefitted from the proximity to the Marcellus Shale, an area that extends along the Appalachian Mountains from southern West Virginia to central New York. Beginning around 2010, gas extraction from hydraulic fracturing transformed this region into the largest source of recoverable natural gas in the United States. This local fuel supply decreased the prices for spot market natural gas in much of the PJM region, and prices in the PJM region often trade at negative basis to the Henry Hub spot price.

The entry of natural gas resources in the PJM region peaked in 2018, with 11.1 GW of generation commercializing that single year. From 2019 to 2022, a total of 8.1 GW of natural gas generation began service, or about a third of the 23 GW observed from 2015–2018. Queue proposals have also declined; over the last three years, only 4.1 GW of new natural gas projects entered the queue, while 15.1 GW of existing queue projects withdrew.[16]

Recent movement in the natural gas spot markets across the U.S. and Europe add another degree of uncertainty to future operations. In 2022, European natural gas supply faced many challenges resulting from the war in Ukraine and subsequent sanctions against Russia. Liquefied natural gas (LNG) imports into the EU and the U.K. in the first half of 2022 increased 66% over the 2021 annual average,[17] primarily from U.S. exporters with operational flexibility. This international natural gas demand is a new competitor for domestic spot-market consumers, resulting in significantly higher fuel costs for PJM's natural gas fleet.

This study assumes that, of the approximately 17.6 GW of natural gas generation in the queue, only those that are proposed uprates of existing generation, or currently under construction, will complete.[18] This results in 3.8 GW of entry from under-construction natural gas resources to be completed for the 2023/2024 Delivery Year. While 12 GW of natural gas have reached a signed Interconnection Service Agreement (ISA) stage, it is unclear what percentage of this capacity may move forward. If significantly more natural gas capacity achieved commercial operation, it could help avoid reliability issues.

Renewable Transition

PJM's projected resource mix continues to evolve toward lower-carbon intermittent resources. Entry into the queue from renewable and storage resources has been growing at an annualized rate of 72% per year since 2018, or 199 GW of capacity entry versus 2.8 GW commercializing and 42.1 GW withdrawn. This influx of renewable projects has led to a joint effort between PJM and its stakeholders to enact queue reforms intended to clear the backlog of projects, improve procedures around permitting and site control, simplify analysis by clustering projects, and accelerate projects that don't require network upgrades. FERC approved the proposed package in November 2022, with expected implementation in 2023.

Commercial Probability and Expanding Beyond the Queue

PJM staff developed several forecasts of the rate by which projects successfully exit the queue (the "commercial probability" of reaching an *In-Service* state). Since 1997, the PJM New Services Queue has tracked proposed generation interconnection projects from their submittal and study stages to completion of an ISA and Wholesale Market Participation Agreement (WMPA) and construction. At any point in the process, a resource may withdraw from the queue, effectively ending its commercial viability.

[16] This capacity represents natural gas projects that were submitted prior to 2020 and withdrawn in the 2020–2022 time frame.

[17] Europe imported record amounts of liquefied natural gas in 2022, U.S. Energy Information Administration, June 14, 2022.

[18] Under construction includes the New Service Queue *Partially in Service – Under Construction* and *Under Construction* statuses.

The study utilized a logistical regression classification algorithm to predict the probability of a project reaching an *In-Service* entry (or *Withdrawn* exit) based on several properties of the project. A logistical regression searches for patterns within training datasets, resulting in a model that can forecast a probability of a result. After applying the logistical regression model for 10 years of historical project completion (Y-queue to present) without project stage, approximately 15.3 GW-nameplate/8.7 GW-capacity were deemed commercially probable out of 178 GW of projects examined.

The model results for thermal resources were reasonably in line with expectations. However, the model produced extremely low entry from onshore wind, offshore wind, solar, solar-hybrid and storage resources. The uncertainty of completion rates of newer resource types, like offshore wind, likely plays a role in these model outcomes. After adjusting the new renewable capacity by Effective Load Carrying Capability (ELCC) derations, this commercial probability analysis estimates net 13.2 GW-nameplate / 6.7 GW-capacity to the system by 2030, as shown in **Figure 4.**

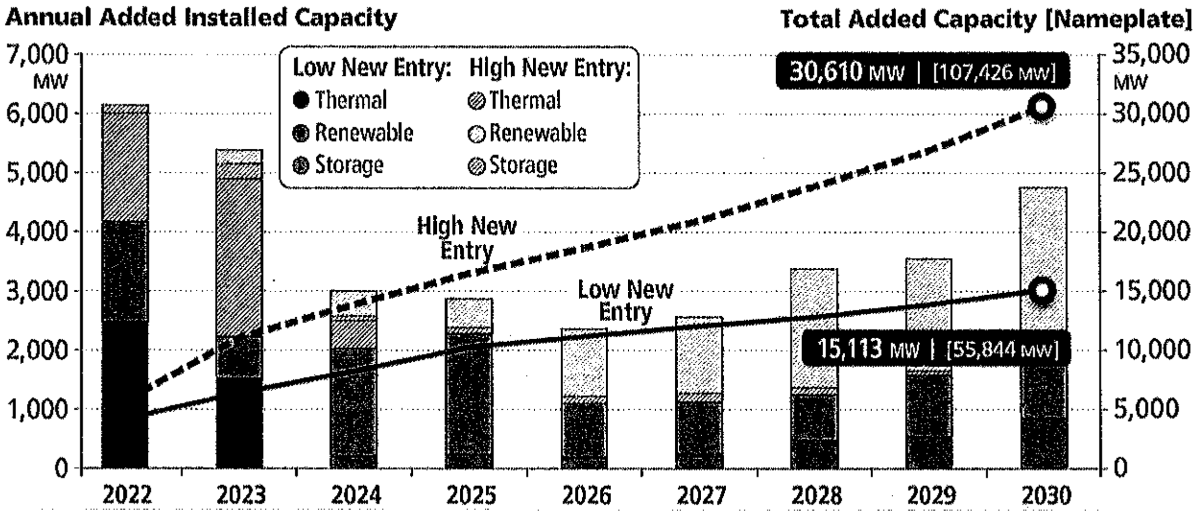
Given that this process may not capture recent policy changes and fiscal incentives toward renewable and storage development, and that the existing queue has fewer resources entered after 2026, PJM staff utilized two S&P Global Power Market Outlook analyses' generation expansion models. As estimates of future entry beyond the queue, these models are used to provide additional insight for the two scenarios: "Low New Entry" utilizes the "Planning Model,"[19] and "High New Entry" utilizes the "Fast Transition" model.[20] Based on these models, PJM added additional capacity to its commercial probability data in each scenario.

These forecasts of generation expansion are economic resource planning solutions, which take state RPS requirements and capacity margins into account to ensure new renewable builds. Over the study period, the Low New Entry scenario adds 42.6 GW-nameplate/8.4 GW-capacity to supply expectations, resulting in total entry of 55.8 GW-nameplate/15.1 GW-capacity. The High New Entry scenario adds 107 GW-nameplate/30.6 GW-capacity after ELCC derations. Net natural gas entry was approximately 5 GW, and renewables was 48.5 GW-nameplate/10.4 GW-capacity, as shown in **Figure 4.**

[19] S&P Global, North American Power Market Outlook, June 2022, planning model. This planning case incorporated effects from the 2021 Infrastructure Investment and Jobs Act, but not the 2022 Inflation Reduction Act.

[20] S&P Global, North American Power Market Outlook, Sept. 2022, Fast Transition model. This planning case assumes carbon net neutrality by 2050 through the IRA and additional policies, such as state clean energy policies, and as such assumes adjustments for increased electrification of heating, tax credits for renewable generation and higher levels of fossil retirements.

Figure 4. Forecast Added Capacity



Impact of Capacity Accreditation on Existing Renewables and Storage

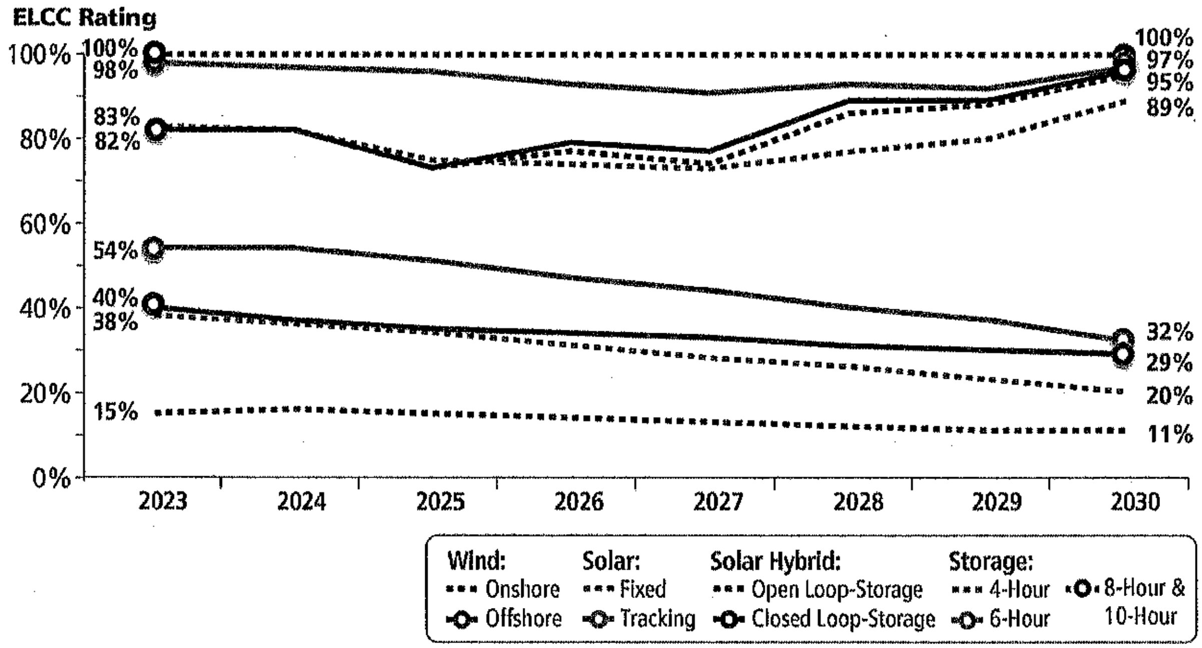
In July 2021, FERC accepted PJM's ELCC methodology for calculating unforced capacity values for intermittent and energy storage capacity resource classes. The ELCC analysis[21] examines load and resource performance uncertainty, and calculates an hourly loss-of-load probability (LOLP) to meet a one-in-10 year loss of load expectation (LOLE) adequacy criteria. The ELCC method examines the alignment of a given resource type's capacity to high risk hours, as well as the change in risk hours proportional to the changes in portfolio size. The adjustments to accredited capacity went into effect in the 2023/2024 BRA executed in June 2022.

This study examined the current renewable generation fleet for the impact of future changes in capacity accreditation. Today, there are approximately 3.5 GW of onshore wind and solar capacity resources participating in the RPM capacity market as intermittent resources. From 2022 to 2030, this accredited capacity is expected to decline by 1.2 GW to 2.3 GW due to portfolio effects resulting in the increase of entry from other intermittent renewable resources.[22] This adjustment is consistent with the renewable expectations presented in the December 2021 Effective Load Carrying Capability (ELCC) Report.

[21] Manual 20, Section 5: PJM Effective Load Carrying Capability Analysis

[22] Approximate nameplate needed to replace 1 MW of thermal generation: Solar – 5.2 MW; Onshore Wind – 14.0 MW; Offshore Wind – 3.9 MW. These are average values.

Figure 5. Effective Load Carrying Capability (ELCC) Rating by Resource Type



Demand Expectations

Load forecasting is an important part of maintaining the reliability of the bulk electric system. Forecasting helps PJM make decisions about how to plan and operate the bulk electric system in a reliable manner, and how to effectively administer competitive power markets. PJM's Resource Adequacy Planning Department publishes an annual Load Forecast Report, which outlines "long-term load forecasts of peak-loads, net energy, load management, distributed solar generation, plug-in electric vehicles and battery storage."

Along with the energy transition, PJM is witnessing a large growth in data center activity. Importantly, the PJM footprint is home to Data Center Alley in Loudoun County, Virginia, the largest concentration of data centers in the world.[23] PJM uses the Load Analysis Subcommittee (LAS) to perform technical analysis to coordinate information related to the forecast of electrical peak demand. In 2022, the LAS began a review of data center load growth and identified growth rates over 300% in some instances.[24] The 2023 PJM Load Forecast Report incorporates adjustments to specific zones for data center load growth, as shown in **Figure 5**.

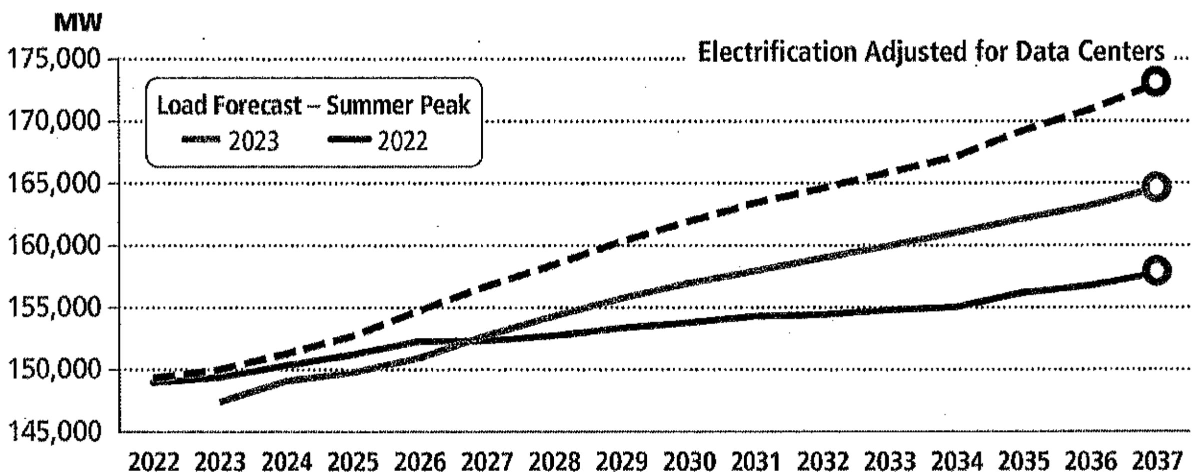
[23] See Loudoun County Department of Economic Development, 2023.

[24] Load Analysis Subcommittee: Load Forecast Adjustment Requests, Andrew Gledhill, Resource Adequacy Planning, Oct. 27, 2022

Additionally, PJM is expecting an increase in electrification resulting from state and federal policies and regulations. The study therefore incorporates an electrification scenario in the load forecast to provide insight on capacity need should accelerated electrification drive demand increases.[25] This accelerated demand increase is consistent with the methodology used in the Emerging Characteristics of a Decarbonizing Grid paper.[26] That paper found electrification to have an asymmetrical impact on demand growth, with demand growth in the winter, mainly due to heating, more than doubling that in the summer. This would move the bulk of the resource adequacy risk from the summer to the winter.

Figure 6 highlights how updated electrification assumptions and accounting for new data center loads have impacted the summer peak between the 2022 and 2023 forecasts.[27]

Figure 6. Impacts of Electrification and Data Center Load on Forecasts



What Does This Mean for Resource Adequacy in PJM?

PJM projects resource adequacy needs through the Reserve Requirement Study (RRS). The purpose of the RRS is to determine the required capacity or Forecast Pool Requirement for future years or delivery years based on load and supply uncertainty. The RRS also satisfies the North America Electric Reliability Corporation/ReliabilityFirst Adequacy Standard BAL-502-RFC-03, Planning Resource Adequacy Analysis, Assessment and Documentation, which requires that the Planning Coordinator performs and documents a resource adequacy analysis that applies a LOLE of one occurrence in 10 years. The RRS establishes the Installed Reserve Margin values for future delivery years. For this study PJM used the most recent 2022 RRS, as well as the 2021 RRS for comparison.

[25] Electrification assumptions are 17 million EVs, 11 million heat pumps, 20 million water heaters, 19 million cooktops in PJM by 2037, built on top of the 2022 Load Forecast.

[26] Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid, May 17, 2022.

[27] 2023 Load Forecast Supplement, PJM Resource Adequacy Planning Department, January 2023.

Combining the resource exit, entry and increases in demand, summarized in **Figure 7**, the study identified some areas of concern. Approximately 40 GW PJM's fossil fuel fleet resources may be pressured to retire as load grows into the 2026/2027 Delivery Year. At current low rates of renewable entry, the projected reserve margin would be 15%, as shown in **Table 1**. The projected total capacity from generating resources would not meet projected peak loads, thus requiring the deployment of demand response. By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%, as projected demand response may be insufficient to cover peak demand expectations, unless new entry progresses at a levels exhibited in the High New Entry scenario. This will require the ability to maintain needed existing resources, as well as quickly incentivize and integrate new entry

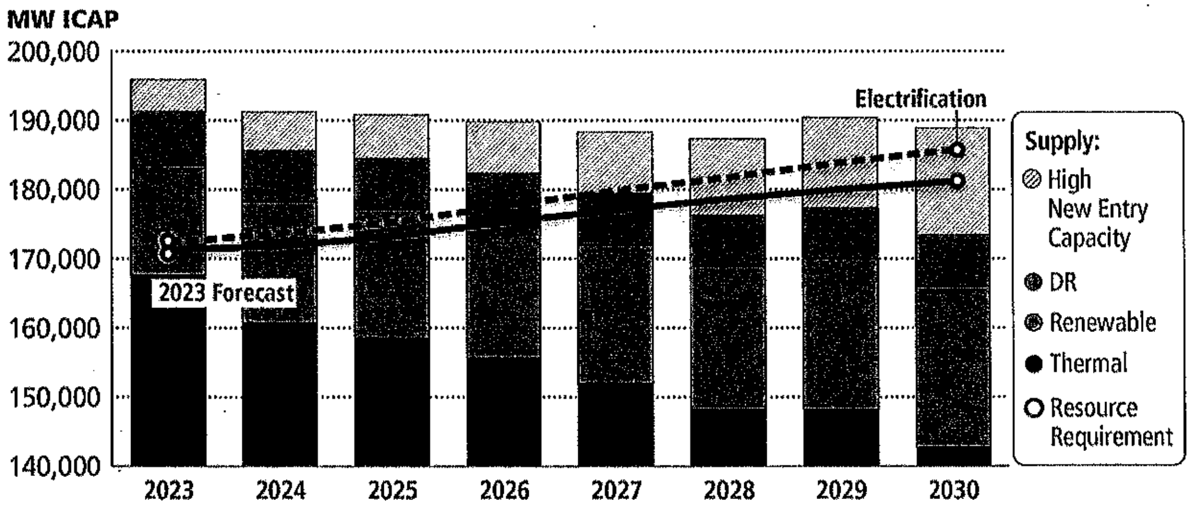
Table 1. Reserve Margin Projections Under Study Scenarios

Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

As witnessed during the rapid transition from coal resources to natural gas resources last decade, PJM markets provide incentives for capacity resources. The challenge will be integrating the level of additional resources envisioned to meet this demand, and therefore addressing issues such as resource capacity accreditation is critical in the near term. The low entry rates shown in our Low New Entry scenario are illustrative of recent completion history applied to the current queue. RTO capacity prices in recent auctions have been low for several delivery years, and capacity margins have historically reached around 28% of peak loads. As capacity reserve levels tighten, the markets will clear higher on the VRR curves, sending price signals to build new generation for reliability needs.

The 2024/2025 BRA, which executed in December 2022, highlighted another area of uncertainty. Queue capacity with approved ISAs/WMPAs is currently very high, approximately 35 GW-nameplate, but resources are not progressing into construction. There has only been about 10 GW-nameplate moving to in service in the past three years. There may still be risks to new entry, such as semiconductor supply chain disruptions or pipeline supply restrictions, which are preventing construction despite resources successfully navigating the queue process.

Figure 7. The Balance Sheet



For the first time in recent history, PJM could face decreasing reserve margins, as shown in **Table 1**, should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue. The amount of generation retirements appears to be more certain than the timely arrival of replacement generation resources, given that the quantity of retirements is codified in various policy objectives, while the impacts to the pace of new entry of the Inflation Reduction Act, post-pandemic supply chain issues, and other externalities are still not fully understood.

The findings of this study highlight the importance of PJM's ongoing stakeholder initiatives (Resource Adequacy Senior Task Force, CAPSTF, Interconnection Process Subcommittee), continued efforts between PJM and state and federal agencies to manage reliability impacts of policies and regulations, and the urgency for coordinated actions to shape the future of resource adequacy.

The potential for an asymmetrical pace within the energy transition, where resource retirements and load growth exceed the pace of new entry, underscores the need for better accreditation, qualification and performance requirements for capacity resources.

The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain the reliability of the bulk electric system. Managing the energy transition through collaborative efforts of PJM stakeholders, state and federal agencies, and consumers will ensure PJM has the tools and resources to maintain reliability.

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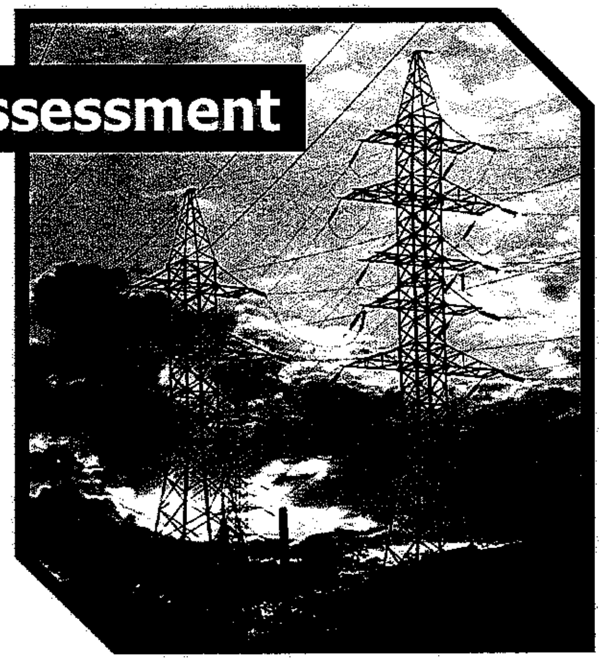
2022 Long-Term Reliability Assessment

December 2022



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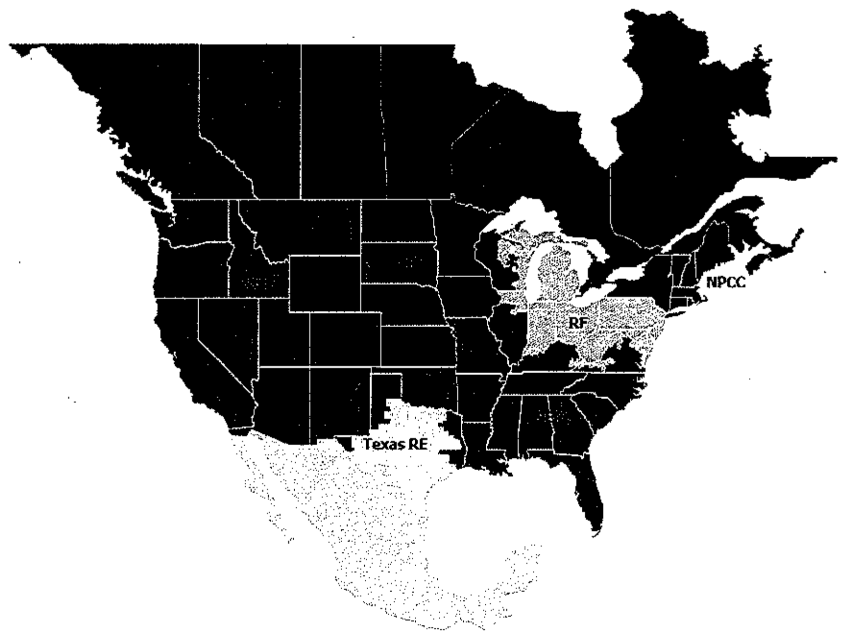
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities, is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entity boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities (LSE) participate in one Regional Entity while associated Transmission Owners/Operators participate in another. A map and list of the assessment areas can be found in the **Regional Assessments** section.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	WECC

About this Assessment

NERC is a not-for-profit international regulatory authority with the mission to assure the reliability of the BPS in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the ERO for North America and is subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC, also known as the Commission) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the North American BPS and serves more than 334 million people. Section 39.11(b) of FERC's regulations provides that "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."

Development Process

This assessment was developed based on data and narrative information NERC collected from the six Regional Entities (see **Preface**) on an assessment area (see **Regional Assessments**) basis to independently evaluate the long-term reliability of the North American BPS while identifying trends, emerging issues, and potential risks during the upcoming 10-year assessment period. The Reliability Assessment Subcommittee, at the direction of NERC's Reliability and Security Technical Committee (RSTC), supported the development of this assessment through a comprehensive and transparent peer review process that leverages the knowledge and experience of system planners, Reliability Assessment Subcommittee members, NERC staff, and other subject matter experts; this peer review process ensures the accuracy and completeness of all data and information. This assessment was also reviewed by the RSTC, and the NERC Board of Trustees (Board) subsequently accepted this assessment and endorsed the key findings.

NERC develops the Long-Term Reliability Assessment (LTRA) annually in accordance with the ERO's Rules of Procedure[1] and Title 18, § 39.11[2] of the Code of Federal Regulations,[3] also required by Section 215(g) of the Federal Power Act, which instructs NERC to conduct periodic assessments of the North American BPS.[4]

Considerations

Projections in this assessment are not predictions of what will happen; they are based on information supplied in July 2022 about known system changes with updates incorporated prior to publication. This *2022 LTRA* assessment period includes projections for 2023–2032; however, some figures and tables examine data and information for the 2022 year. This assessment was developed by using a consistent approach for projecting future resource adequacy through the application of the ERO Reliability Assessment Process.[5] NERC's standardized data reporting and instructions were developed through stakeholder processes to promote data consistency across all the reporting entities that are further explained in **Demand Assumptions and Resource Categories.** Reliability impacts related to cyber and physical security risks are not specifically addressed in this assessment; this assessment is primarily focused on resource adequacy and operating reliability. NERC leads a multi-faceted approach through NERC's Electricity-Information Sharing and Analysis Center (E-ISAC) to promote mechanisms to address physical and cyber security risks, including exercises and information-sharing efforts with the electricity industry.

The LTRA data used for this assessment creates a reference case dataset that includes projected on-peak demand and system energy needs, demand response (DR), resource capacity, and transmission projects. Data from each Regional Entity is also collected and used to identify notable trends and emerging issues. This bottom-up approach captures virtually all electricity supplied in the United States, Canada, and a portion of Baja California, Mexico. NERC's reliability assessments are developed to inform industry, policy makers, and regulators as well as to aid NERC in achieving its mission to ensure the reliability of the North American BPS.

[1] NERC Rules of Procedure - Section 803
[2] Section 39.11(b) of FERC's regulations states the following: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission."
[3] Title 18, § 39.11 of the Code of Federal Regulations
[4] BPS reliability, as defined in the How **NERC Defines BPS Reliability** section of this report, does not include the reliability of the lower-voltage distribution systems that account for 80% of all electricity supply interruptions to end-use customers.
[5] *ERO Reliability Assessment Process Document*, April 2018: https://www.nerc.com/comm/PC/Reliability%20Assessment%20Subcommittee%20RAS%202013/ERO%20Reliability%20Assessment%20Process%20Document.pdf

Assumptions

In this *2022 LTRA*, the baseline information on future electricity supply and demand is based on several assumptions:[6]

- Supply and demand projections are based on industry forecasts submitted and validated in July 2022. Any subsequent demand forecast or resource plan changes may not be fully represented; however, updated data submitted throughout the report drafting time frame have been included where appropriate.
- Peak demand is based on average peak weather conditions and assumed forecast economic activity at the time of submittal. Weather variability is discussed in each Regional Entity's self-assessment.
- Generation and transmission equipment will perform at historical availability levels.
- Future generation and transmission facilities are commissioned and in service as planned, planned outages take place as scheduled, and retirements take place as proposed.
- Demand reductions expected from dispatchable and controllable DR programs will yield the forecast results if they are called on.
- Other peak demand-side management programs, such as energy efficiency (EE) and price-responsive DR, are reflected in the forecasts of total internal demand.

Reading this Report

This report is compiled into two major parts:

- A reliability assessment of the North American BPS with the following goals:
  - Evaluate industry preparations that are in place to meet projections and maintain reliability
  - Identify trends in demand, supply, and reserve margins
  - Identify emerging reliability issues
  - Focus the industry, policy makers, and the general public's attention on BPS reliability issues
  - Make recommendations based on an independent NERC reliability assessment process
- A regional reliability assessment that contains the following:
  - 10-year data dashboard
  - Summary assessments for each assessment area
  - Focus on specific issues identified through industry data and emerging issues
  - Identify regional planning processes and methods used to ensure reliability

[6] Forecasts cannot precisely predict the future. Instead, many forecasts report probabilities with a range of possible outcomes. For example, each regional demand projection is assumed to represent the expected midpoint of possible future outcomes. This means that a future year's actual demand may deviate from the projection due to the inherent variability of the key factors that drive electrical use, such as weather. In the case of the NERC regional projections, there is a 50% probability that actual demand will be higher than the forecast midpoint and a 50% probability that it will be lower (50/50 forecast).

Executive Summary

Introduction

This *2022 LTRA* is the ERO's independent assessment and comprehensive report on the adequacy of planned BPS resources to reliably meet the electricity demand across North America over the next ten years. This *2022 LTRA* also identifies reliability trends, emerging issues, and potential risks that could impact the long-term reliability, resilience, and security of the BPS.

The findings in this 2022 LTRA are vitally important to understand the reliability risks to the North American BPS as it is currently planned and as it is being shaped by government policies, regulations, consumer preferences, and economic factors. Energy systems and the electricity grid are undergoing unprecedented change on a scope, scale, and speed that challenges the ability to foresee—and design for—their future states. This report contains future energy sufficiency metrics that serve as guideposts for the reliability of the North American electric grid on its current trajectory. It also describes the relevant trends that are propelling the grid's transformation and have the potential to alter the ability of the BPS to service the energy needs of communities and industries in North America.

Projected Area Supply Shortfalls

The **Resource Capacity and Energy Risk Assessment** section of this report identifies potential electricity supply shortfalls under normal and more severe conditions. NERC's assessment assumes the latest demand forecasts, resource levels, and area transfer commitments as well as accounts for expected generator retirements, resource additions, and demand-side resources.

High Risk Areas[7]

Most areas are projected to have adequate electricity supply resources to meet demand forecasts associated with normal weather. However, areas shown in red (high risk) in Figure 1 do not meet resource adequacy criteria, such as the 1-day-in-10 year load-loss metric during periods of the assessment horizon. This indicates that the supply of electricity for these areas is more likely to be insufficient in the forecast period and that more firm resources are needed. The following is a summary of the high-risk areas (details are discussed in later sections of this *2022 LTRA*):

- **In the Midcontinent Independent System Operator (MISO)** area, the previously-reported reserve margin shortfall has advanced by one year, resulting in a 1,300 MW capacity deficit for the summer of 2023. The projected shortfall continues an accelerating trend since both the *2020 LTRA* and the *2021 LTRA* as older coal, nuclear, and natural gas generation exit the system faster than replacement resources are connecting.
- **NPCC-Ontario** also continues to project a reserve margin shortfall in 2025 and beyond. The capacity deficit of 1,700 MW is driven by generation retirements and lengthy planned outages at nuclear units undergoing refurbishment.
- Resource additions in the **California/Mexico (CA/MX) part of WECC** are alleviating capacity risks, but energy risks persist. Planned reserve margins meet annual reserve margin targets for the duration of the 10-year horizon. However, overall variability in both the resource mix and demand profile contributes to shortfall risk periods, mainly in summer months around sunset, when expected supplies are not sufficient to meet the demand.

Elevated Risk Areas[8]

Extreme temperatures and prolonged severe weather conditions are increasingly impacting the BPS. Extreme weather impacts the system by increasing electricity demand and forcing generation and other resources off-line. While a given area may have sufficient capacity to meet resource adequacy requirements, it may not have sufficient availability of resources during extreme and prolonged weather events. Therefore, **long-duration weather events increase the risk of electricity supply shortfalls.**

In many parts of North America, peak electricity demand is increasing, and forecasting demand and its response to extreme temperatures and abnormal weather is increasingly uncertain. Electrification and distributed energy resource (DER) trends can be expected to further contribute to demand growth and sensitivity to weather patterns. Specifically, electrification of residential heating requires the system to serve especially high demand on especially cold days.

[7] An assessment area is deemed to be "high risk" by failing to meet the established resource adequacy target or requirement. The established resource adequacy target is not established by NERC, but instead by the prevailing regulatory authority or market operator. Generally, these targets/requirements are based on a 1 day/event load-loss in a 10-year planning requirement. High risk areas have a probability of load shed greater than the requirement/target. Simply said, high risk areas do not meet resource adequacy requirements.

[8] An assessment area is deemed to be "elevated risk" when it meets the established resource adequacy target or requirement, but the resources fail to meet demand and reserve requirements under the probabilistic or deterministic scenario analysis. The established resource adequacy target is not established by NERC, but instead the prevailing regulatory authority or market operator. Simply, elevated risk areas meet resource adequacy requirements, but they may face challenges meeting load under extreme conditions.

Electricity supplies can decline in extreme weather for many reasons. Generators that are not designed or prepared for severe cold or heat can be forced off-line in increasing amounts. Wide area weather events can also impact multiple balancing and transmission operations simultaneously that limit the availability of transfers. Fuel production or transportation disruptions could limit the amount of natural gas or other fuels available for electric generation. Wind, solar, and other variable energy resource (VER) generators are dependent on the weather.

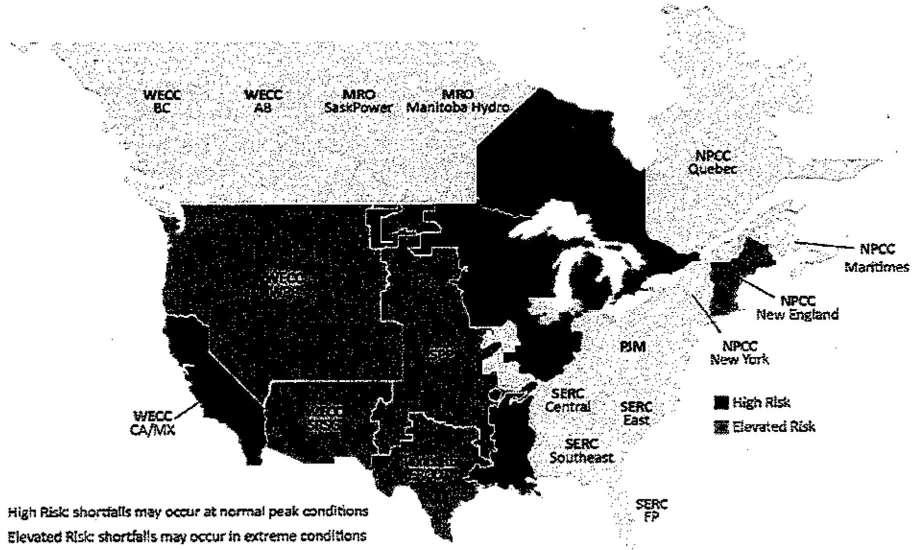


Figure 1: Risk Area Summary 2023–2027

Areas in orange (elevated risk) in Figure 1 meet resource adequacy criteria and have sufficient energy and capacity for normal forecasted conditions, but they are at risk of shortfall in extreme conditions:

- All three assessment areas in the **U.S. West—CA/MX, Western Power Pool (WPP), and the Southwest Reserve Sharing Group (SRSG)**—have increasing demand and resource mix variability. In normal conditions, the expected demand and resource variability is balanced across the area as excess supply from one part of the system is delivered through the transmission network to places where demand is higher than supply. However, more extreme summer temperatures that stress large portions of the Interconnection reduce the availability of excess supply for transfer while also reducing the transmission network's ability to transfer the excess.
- Reliability during extreme winter weather remains a concern in **Texas.** ERCOT's winter peak load varies substantially (as much as 12.5%) between the coldest temperatures of an average year and a more extreme year as might be experienced once per decade. A high number of forced outages of the thermal and wind generation fleet have been an issue in severe winter weather. Improved generator availability resulting from winter preparedness programs and reforms implemented by Texas regulators, ERCOT, and Generator Owners since February 2021 are expected to reduce the risk that electricity supplies will be insufficient during a severe winter storm.
- **SPP** is exposed to energy risks in ways that are similar to both Texas and the U.S. West. Severe weather in SPP is likely to cause high generator outages and poses a risk to natural gas fuel supplies. In addition, the penetration of wind generation makes the resource mix variable and exposed to insufficient energy during low wind periods.
- In **New England,** limited natural gas infrastructure can impact winter reliability due to increased heating demand and the potential for supply disruptions to generators. Liquefied natural gas facilities and sufficient generators with stored backup fuels are critical to electric reliability.

Continuing Resource Mix Changes and Implications for Reliability

This *2022 LTRA* contains the latest industry projections for generation and other resources, including DR, DERs, and the resulting **Continuing Resource Mix Changes and Implications for Reliability** found at this link. Highlights of these trends and the implications for reliability include the following:

- **Reliable Interconnection of Inverter-Based Resources:** Reliably integrating inverter-based resources (IBR), which include most solar and wind generation, onto the grid is paramount. Over 70% of the new generation in development for connecting to the BPS over the next 10 years is solar, wind, and hybrid (a generating source combined with a battery).
- **Accommodating Large Amounts of Distributed Energy Resources:** Preparing the grid to operate with increasing levels of distribution resources must also be a priority in many areas. Solar photovoltaic (PV) DERs are projected to reach over 80 GW by the end of this 10-year assessment, a 25% increase in projection since the *2021 LTRA*; a total of 12 assessment areas project to double the amount of DERs in their areas by 2032.

- **Managing the Pace of Generation Retirements:** As new resources are introduced and older traditional generators retire, careful attention must be paid to power system and resource mix reliability attributes. Within the 10-year horizon, over 88 GW of generating capacity is confirmed for retirement through regional transmission planning and integrated processes. Effective regional transmission and integrated resource planning processes are the key to managing the retirement of older nuclear, coal-fired, and natural gas generators in a manner that prevents energy risks or the loss of necessary sources of system inertia and frequency stabilization that are essential for a reliable grid.
- **Maintaining Essential Reliability Services:** The changing composition of the North American resource mix calls for more robust planning approaches to ensure adequate essential reliability services.[9] Retiring conventional generation is being replaced with large amounts of wind and solar; planning considerations must adapt with more attention to essential reliability services. As replacement resources are interconnected, these new resources should have the capability to support voltage, frequency, and dispatchability. Various technologies can contribute to essential reliability services, including variable energy resources; however, policies and market mechanisms need to reflect these requirements to ensure these services are provided and maintained. Regional transmission organizations, independent system operators, and FERC have taken steps in this direction, and these positive steps must continue.

Trends and Implications for Reliability

Demand Trends and Implications as well as **Transmission Development Trends and Implications** found at these links affect long-term reliability and the sufficiency of electricity supplies. Several key insights emerge from the latest industry data:

- **Peak Demand and Energy Growth:** Projected growth rates of electricity peak demand and energy in North America are increasing for the first time in recent years. Government policies for the adoption of electric vehicles (EVs) and other energy transition programs have the potential to significantly influence demand. Demand-side management programs, including conservation, EE, and DR continue to offset demand and contribute to load management. Where rapid transition is proposed, early alignment and coordination on energy and infrastructure are needed.
- **Insufficient Transmission for Large Power Transfers:** Transmission development projections remain near the averages of the past five NERC LTRAs. There has been some increase in the number of miles of transmission line projects for integrating renewable generation over the next 10 years compared to the *2021 LTRA* projections. Transmission investment is important for reliability and resilience as well as the integration of new generation resources.
- **Emerging Electrification Challenges:** Several emerging issues and trends have the potential to impact future long-term projections of demand and resources. In addition to EV and electrification issues, cryptocurrency mining may have a notable impact on demand and resources in some areas. Resource development may be significantly altered by supply chain issues and differ from projections used in this *2022 LTRA*. Notable emerging issues and their potential implications are discussed in this report.

Conclusions and Recommendations

The energy and capacity risks identified in this assessment underscore the need for reliability to be a top priority for the resource and system planning community of stakeholders. Planning and operating the grid must increasingly account for different characteristics and performance in electricity resources as the energy transition continues. General actions for industry and policymakers to address the reliability risks described in this *2022 LTRA* include the following:

- Manage the pace of generator retirements until solutions are in place that can continue to meet energy needs and provide essential reliability services
- Include extreme weather scenarios in resource and system planning
- Address IBR performance and grid integration issues
- Expand resource adequacy evaluations beyond reserve margins at peak times to include energy risks for all hours and seasons
- Increase focus on DERs as they are deployed at increasingly impactful levels
- Mitigate the risks that arise from growing reliance on just-in-time fuel for electric generation and the interdependent natural gas and electric infrastructure
- Consider the impact that the electrification of transportation, space heating, and other sectors may have on future electricity demand and infrastructure

Specific *LTRA* recommendations are provided on the following page and in the appropriate sections of this report.

[9] Essential Reliability Services: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/ERS%20Abstract%20Report%20Final.pdf

Reducing the Risk of Insufficient Energy

The impact of wide-area and long-duration extreme weather events, such as the February 2021 South Central U.S. cold weather event and the August 2020 Western U.S. wide-area heat event, have underscored the need to consider extreme scenarios for resource planning. Energy risks emerge when weather-dependent generation is impacted by abnormal atmospheric conditions or when extreme conditions disrupt fuel supplies. In areas with a high dependence on VERs and natural-gas-fired generation, Prospective Reserve Margins (PRM) are not sufficient for measuring resource adequacy:

- Industry and regulators should conduct all-hours energy availability analyses for evaluating and establishing resource adequacy and include extreme condition criteria in integrated resource planning and wholesale market designs.
- The ERO and industry should prioritize the development of Reliability Standard requirements to address energy risks in operations and planning. NERC's Reliability Standards Project 2022-03 should be closely monitored, and stakeholder experts should contribute to developing effective requirements for entities to assess energy risks and implement corrective actions in all time horizons.
- State and provincial regulators and independent system operators (ISO)/regional transmission operators (RTO) should have mechanisms they can employ to prevent the retirement of generators that they determine are needed for reliability, including the management of energy shortfall risks.
- Regulatory and policy-setting organizations should use their full suite of tools to manage the pace of retirements and ensure that replacement infrastructure can be timely developed and placed in service. If needed, the Department of Energy should use its 202(c) authority as called upon by electric system operators.
- Resource planners and policymakers must pay careful attention to the pace of change in the resource mix as well as update capacity and energy risk studies (including all-hours probabilistic analysis) with accurate resource projections.

Planning and Adapting for IBRs and DERs

IBRs, including most solar and wind as well as new battery or hybrid generation, respond to disturbances and dynamic conditions based on programmed logic and inverter controls. The tripping of BPS-connected solar PV generating units and other control system behavior during grid faults has caused a sudden loss of generation resources over wide areas in some cases. As areas become more reliant on IBRs for their electricity generation, it is critically important to reduce risks from IBR performance issues. Likewise, explosive growth in DERs underscores the need to incorporate them into system planning:

- The ERO and Industry should take steps to ensure that IBRs operate reliably and the system is planned with due consideration for their unique attributes. NERC has developed an IBR strategy document to address IBR performance issues that illustrates current and future work to mitigate emerging risks in this area.[10] Regulators, industry-standards-setting organizations, trade forums, and manufacturers each have a role to play to address IBR performance issues.
- Industry should increase its focus on the technical needs for the BPS to reliably operate with increased amounts of DERs. Growth promises both opportunities and risks for reliability. Increased DER penetrations can improve local resilience at the cost of reduced operator visibility into loads and resource availability. Data sharing, models, and information protocols are needed to support BPS planners and operators. DER aggregators will also play an increasingly important role for BPS reliability in the coming years. Increasing DER participation in wholesale markets should be considered in connection with potential impacts to BPS reliability, contingency selection, and how any reliability gaps might be mitigated.

Addressing the Reliability Needs of Interdependent Electricity and Natural Gas Infrastructures

Natural gas is an essential fuel for electricity generation that bridges the reliability needs of the BPS during this period of energy transition. As natural-gas-fired generation continues to increase, vulnerabilities associated with natural gas delivery to generators can potentially result in generator outages. Energy stakeholders must urgently act to solve reliability challenges that arise from interdependent natural gas and electricity infrastructure:

- ERO and Industry planners should enhance guidelines for assessing and reducing risks through system and resource planning studies and develop appropriate Reliability Standards requirements to ensure corrective actions are put in place.
- Regulators and other energy stakeholders must also take steps to promote coordination on interdependencies. The forum convened by the North American Energy Standards Board is one such important action that should be broadly supported.[11]

[10] https://www.nerc.com/comm/Documents/NERC_IBR_Strategy.pdf

[11] https://www.nerc.com/news/Pages/-FERC,-NERC-Encourage-NAESB-to-Convene-Gas-Electric-Forum-to-Address-Reliability-Challenges.aspx

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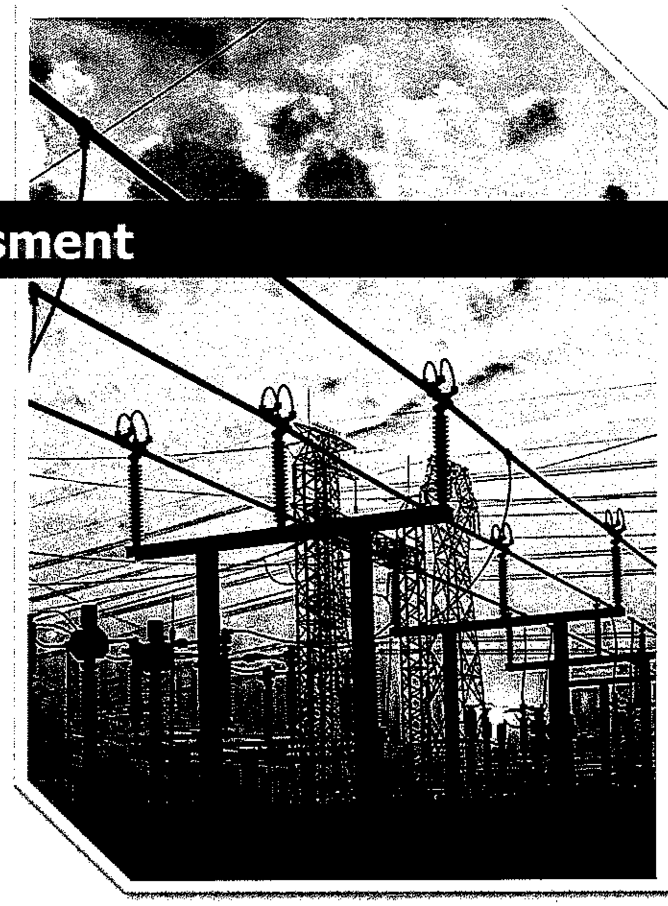

2023 Summer Reliability Assessment

May 2023

Embargoed until 12:30 p.m. Eastern May 17, 2023

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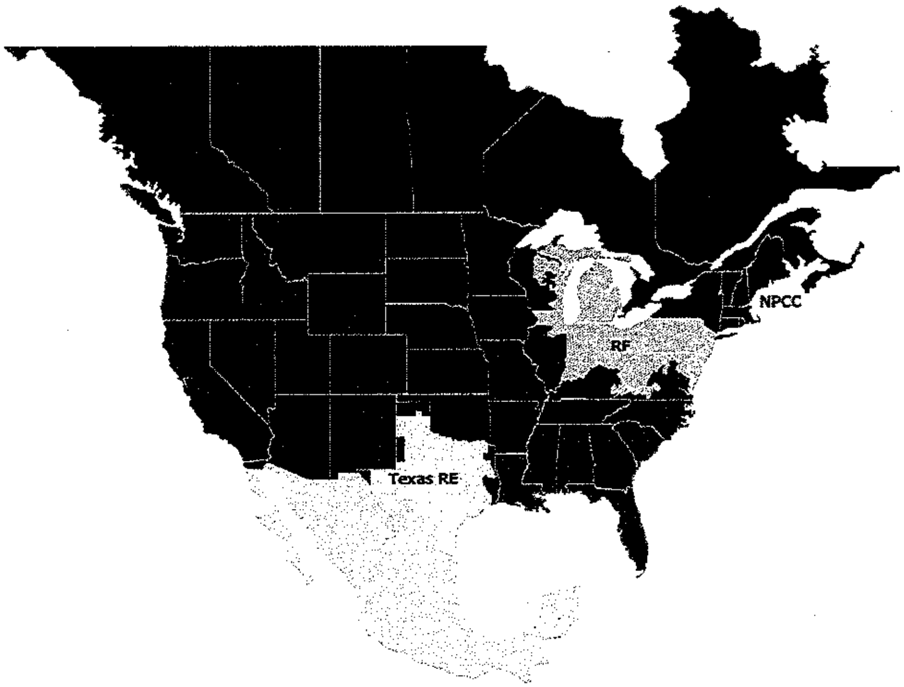

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WECC	WECC

About this Assessment

NERC's *2023 Summer Reliability Assessment* (*SRA*) identifies, assesses, and reports on areas of concern regarding the reliability of the North American BPS for the upcoming summer season. In addition, the *SRA* presents peak electricity demand and supply changes and highlights any unique regional challenges or expected conditions that might affect the reliability of the BPS. The reliability assessment process is a coordinated reliability evaluation between the NERC Reliability Assessment Subcommittee, the Regional Entities, and NERC staff with demand and resource projections obtained from the assessment areas. This report reflects an independent assessment by NERC and the ERO Enterprise and is intended to inform industry leaders, planners, operators, and regulatory bodies so that they are better prepared to take necessary actions to ensure BPS reliability. This report also provides an opportunity for the industry to discuss plans and preparations to ensure reliability for the upcoming summer period.

Key Findings

NERC's annual SRA covers the upcoming four-month (June–September) summer period. This assessment provides an evaluation of generation resource and transmission system adequacy as well as energy sufficiency to meet projected summer peak demands and operating reserves. This includes a deterministic evaluation of data submitted for peak net demand hour and peak risk hour as well as results from recently updated probabilistic analyses. Additionally, this assessment identifies potential reliability issues of interest and regional topics of concern. While the scope of this seasonal assessment is focused on the upcoming summer, the key findings are consistent with risks and issues that NERC has highlighted in the *2022 Long-Term Reliability Assessment* and other earlier reliability assessments and reports.

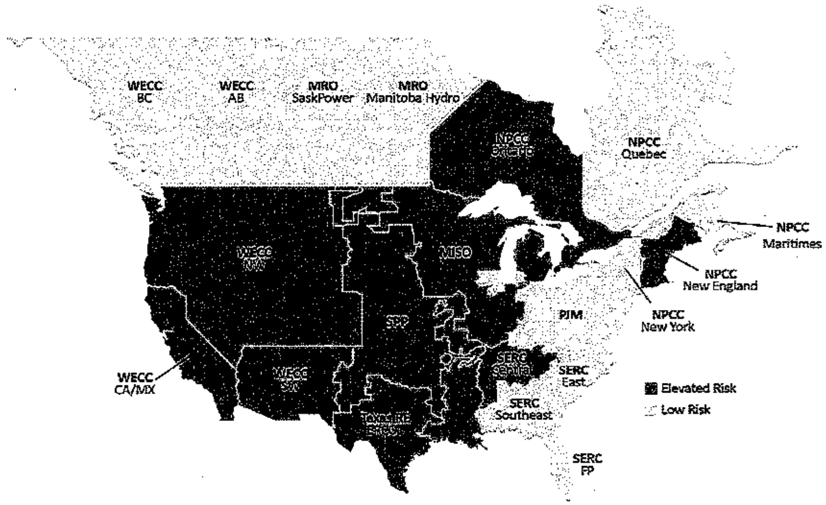
The following findings are NERC's and the ERO Enterprise's independent evaluation of electricity generation and transmission capacity as well as potential operational concerns that may need to be addressed for the 2023 summer.

Resource Adequacy Assessment and Energy Risk Analysis

All areas are assessed as having adequate anticipated resources for normal summer peak load and conditions (see **Figure 1**). However, the following areas face risks of electricity supply shortfalls during periods of more extreme summer conditions. This determination of elevated risk is based on analysis of plausible scenarios, including 90/10 demand forecasts and historic high outage rates as well as low wind, solar photovoltaic (PV), or hydro energy conditions:

- **Midcontinent ISO (MISO):** The risk of being unable to meet reserve requirements at peak demand this summer in MISO is lower than in 2022 due to additional firm import commitments and lower peak demand forecast. MISO is expected to have sufficient resources, including firm imports, for normal summer peak demand. Wind generator performance during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system to maintain reliability. MISO can face challenges in meeting above-normal peak demand if wind generator energy output is lower than expected. Furthermore, the need for external (non-firm) supply assistance during more extreme demand levels will depend largely on wind energy output. Results of MISO's capacity auction have not been released at the time of this assessment, and these could change MISO's firm resources for the summer.
- **NPCC-New England:** Anticipated resources in New England are projected to be lower than in 2022 but are expected to remain sufficient for meeting operating reserve requirements at normal peak demand. Operating procedures for obtaining emergency resources or non-firm supplies from neighboring areas are likely to be needed during more extreme demand or low resource conditions.
- **NPCC-Ontario:** Planned nuclear outage for refurbishment have reduced the electricity supply resources serving the province. Additionally, load growth is contributing to a constrained transmission network during high-demand conditions that may not be able to deliver sufficient supply to the Windsor-Essex area in the southwest part of the province. Additional generator outages or extreme demand can lead to reserve shortages and a need to seek non-firm imports. Ontario could potentially see a significant increase in reliance on imports this summer under both normal peak (50/50) and extreme (90/10) demand scenarios.
- **SERC-Central:** Compared to the summer of 2022, forecasted peak demand has risen by over 950 MW while growth in anticipated resources has been flat. The assessment area is expected to have sufficient supply for normal peak demand while demand-side management or other operating mitigations can be expected for above-normal demand or high generator-outage conditions.
- **Southwest Power Pool (SPP):** Reserve margins have also fallen in SPP as a result of increasing peak demand and declining anticipated resources. Like MISO, the energy output of SPP's wind generators during periods of high demand is a key factor in determining whether there is sufficient electricity supply on the system. SPP can face energy challenges in meeting extreme peak demand or managing periods of thermal or hydro generator outages if wind resource energy output is below normal.
- **Texas (ERCOT):** The area is experiencing strong growth in both resources and forecasted demand. ERCOT added over 4 GW of new solar PV nameplate capacity to the ERCOT grid since 2022. Additionally, load reductions from dispatchable demand response programs have grown by over 18% to total 3,380 MW. ERCOT's peak demand forecast has also risen by 6% as a result of economic growth. Resources are adequate for peak demand of the average summer; however, dispatchable generation may not be sufficient to meet reserves during an extreme heat-wave that is accompanied by low winds.
- **U.S. Western Interconnection:** Resources across the area are sufficient to support normal peak demand. However, wide-area heat events can expose the WECC assessment areas of California/Mexico (CA/MX), Northwest (NW), and Southwest (SW) to risk of energy supply shortfall as each area relies on regional transfers to meet demand at peak and the late afternoon to evening hours when energy output from the area's vast solar PV resources are diminished. Within the Western Interconnection, entities are planning to install over 2 GW of new battery energy storage systems, which can help reduce energy risks from resource variability. Wildfire risks to the transmission network, which often accompany these wide-area heat events, can limit electricity transfers and result in localized load shedding.

All other areas have sufficient resources to manage normal summer peak demand and are at low risk of energy shortfalls from more extreme demand or generation outage conditions. Anticipated Reserve Margins meet or surpass the Reference Margin Level, indicating that planned resources in these areas are adequate to manage the risk of a capacity deficiency under normal conditions. Furthermore, based on risk scenario analysis in these areas, resources and energy appear adequate. **Figure 1** below summarizes the risk status for all assessment areas.



Seasonal Risk Assessment Summary	
High	Potential for insufficient operating reserves in normal peak conditions
Elevated	Potential for insufficient operating reserves in above-normal conditions
Low	Sufficient operating reserves expected

Figure 1: Summer Reliability Risk Area Summary

Other Reliability Issues

- **Stored supplies of natural gas and coal are at high levels, but industry is monitoring for potential generator fuel delivery risks.** The natural gas supply and infrastructure is vitally important to electric grid reliability, even as renewable generation satisfies more of our energy needs. Fuel supply and delivery infrastructure must be capable of meeting the ramp rates of natural-gas-fired generators as they balance the system when solar generation output declines. Likewise, owners and operators of some coal-fired generators in the U.S. Southeast report challenges in arranging coal replenishment due to mine closures and transport delays. Consequently, some Balancing Authorities (BA) continue to employ coal-conservation measures that began in late 2022 in order to maintain sufficient stocks for peak months.
- **New environmental rules that restrict power plant emissions will limit the operation of coal-fired generators in 23 states, including Nevada, Utah, and several states in the Gulf Coast, mid-Atlantic, and Midwest.** The U.S. Environmental Protection Agency's (EPA) Good Neighbor Plan, finalized on March 15, 2023, ensures that affected states meet the Clean Air Act's "Good Neighbor" requirements by reducing pollution that significantly contributes to problems attaining and maintaining the EPA's health-based air quality standard[1] for ground-level ozone (i.e., smog) in downwind states.[2] Coal and natural-gas-fired generators in states affected by the Good Neighbor Plan will likely meet tighter emissions restrictions primarily by limiting hours of operation in this first year of implementation rather than through adding emissions control equipment. RCs in summer-peaking areas typically are not able to authorize extended outages to upgrade systems during this summer season in order to ensure sufficient resources for high demand. The final rule approved by the EPA includes provisions designed to give grid owners and operators flexibility to help maintain reliability, including allowance-trading mechanisms. Consequently, RCs, BAs, and GOs will need to be vigilant for emissions rule constraints that affect generator dispatchability and the potential need for emission allowance trades or waivers to meet high demand or low resource conditions. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.
- **Low inventories of replacement distribution transformers could slow restoration efforts following hurricanes and severe storms.** The electric industry continues to face a shortage of distribution transformers as a result of production not keeping pace with demand. A survey by the American Public Power Association revealed that many utilities have low levels of emergency stocks that are used for responding to natural disasters and catastrophic events.[3]

[1] This standard is known as the 2015 Ozone National Ambient Air Quality Standards (NAAQS)
[2] https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs#summary

[3] https://www.publicpower.org/periodical/article/appa-survey-members-shows-distribution-transformer-production-not-meeting-demand

Asset sharing programs used by utilities provide visibility and voluntary equipment sharing to maximize resources; however, electricity customers may experience delayed restoration of power following storms as crews must work to obtain new equipment. New efficiency standards for distribution transformers proposed by the U.S. Department of Energy could further exacerbate the transformer supply shortages.[4]

- **Supply chain issues present maintenance and summer preparedness challenges and are delaying some new resource additions.** Difficulties in obtaining sufficient labor, material, and equipment as a result of broad economic factors has affected preseason maintenance of transmission and generation facilities in North America. These supply chain issues have led some owners and operators to delay or cancel maintenance activities that are typically performed to ensure facilities are ready for summer conditions. Additionally, GOs in some areas that were preparing to interconnect new generation are facing delays that will prevent some from being available to meet expected peak summer demand. This includes areas in the U.S. Southeast and the U.S. part of the Western Interconnection (see **Regional Assessments Dashboards** for details). These supply chain issues can exacerbate concerns in elevated risk areas (**Figure 1**) and add challenges to operators across the BPS. Should project delays emerge, affected GOs and TOs must communicate changes to BAs, TOPs, and RCs so that impacts are understood and steps are taken to reduce risks of capacity deficiencies or energy shortfalls.
- **Winter precipitation is expected to improve the water supply for hydro generation in parts of the U.S. West, but low water levels on major reservoirs remain a concern for electricity generation.** Significant amounts of rainfall and high elevation snow are expected to help replenish reservoirs and maintain river flows that provide energy for most of California's hydroelectric facilities. However, reservoirs at the largest hydro facilities in the U.S. West, including Washington's Grand Coulee Dam and the Hoover Dam on the Arizona-Nevada border, remain at historic low levels, potentially limiting hydroelectric energy output. Power from these plants is used throughout the U.S. Western Interconnection.
- **Unexpected tripping of wind and solar PV resources during grid disturbances continues to be a reliability concern.** NERC has analyzed multiple large-scale disturbances on the BPS that involved widespread loss of inverter-based resources (IBR). In 2021 and 2022, the Texas Interconnection experienced widespread IBR loss events, like those previously observed in the California area. Similarly, four additional solar PV loss events occurred between June and August 2021 in California. In 2022, ERCOT required GOs to submit mitigation plans, and corrective measures are being implemented in 2023. In March 2023, NERC issued the *Inverter-Based Resource Performance Issues Alert* to GOs of Bulk Electric System (BES) solar PV generating resources.[5] As a Level 2 alert, it contains recommended actions for GOs of grid-connected solar PV resources, including steps to coordinate protection and controller settings, so that the resources will reliably operate during grid disturbances.
- **Curtailment of electricity transfers to areas in need during periods of high regional demand is a growing reliability concern.** During energy emergencies and periods of transmission system congestion, RCs and BAs may curtail area transfers for various reasons using established procedures and protocols. While the curtailments alleviate an issue in one part of the system, they can contribute to supply shortages or effect local transmission system operations in another area. Two recent extreme temperature events highlight the effect of transfer curtailments on area supply needs during energy emergencies. During the September 2022 wide-area heat dome, a BA in the WECC-SW assessment area declared an energy emergency when the neighboring assessment area, California Independent System Operator (CAISO), curtailed transfers in order to meet the high demand within their own area. During Winter Storm Elliott, firm exports were curtailed from PJM during a period of widespread energy emergencies in the U.S. Eastern Interconnection.

  For the summer of 2023, several areas identified as having capacity or energy risks are relying on imports of electricity supplies. These areas include MISO, NPCC-Ontario, SERC-Central, and the assessment areas in the U.S. Western Interconnection. A wide-area heat event that severely affects regional demand or generator availability presents an added concern in areas that are dependent on imports for managing high electricity demand.
- **In addition to the risk items identified in the Key Findings, resource outages will continue to present challenges in many areas during "near-peak" demand conditions that occur in spring and fall.** Many parts of North America experience elevated temperatures that extend beyond the summer (June–September) months into periods when BPS equipment owners and operators historically scheduled outages for maintenance. Increasingly, BAs are facing resource constrained periods during shoulder months as unseasonable temperatures coincide with generator unavailability. Careful attention to long-term weather forecasts and the potential for unusual heat patterns in the shoulder months is important to inform the need for more conservative outage coordination periods.

[4] https://www.energy.gov/articles/doe-proposes-new-efficiency-standards-distribution-transformers

[5] https://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/NERC%20Alert%20R-2023-03-14-01%20Level%202%20-%20Inverter-Based%20Resource%20Performance%20Issues.pdf

Recommendations

To reduce the risk of electricity shortfalls on the BPS this summer, NERC recommends the following:

- RCs, BAs, and TOPs in the elevated risk areas identified previously in the key findings should take the following actions:
  - Review seasonal operating plans and the protocols for communicating and resolving potential supply shortfalls in anticipation of potentially extreme demand levels
  - Employ conservative generation and transmission outage coordination procedures commensurate with long-range weather forecasts to ensure adequate resource availability
  - Engage state or provincial regulators and policymakers to prepare for efficient implementation of demand side management mechanisms called for in operating plans
- GOs with solar PV resources should implement recommendations in the inverter-based resource performance issues alert that NERC issued in March 2023.
- RCs, BAs, and GOs in states affected by the new Good Neighbor Plan should be familiar with its provisions for ensuring electric reliability and have protocols in place to act to preserve generation resources when necessary to support periods of high demand. State regulators and industry should have protocols in place at the start of summer for managing emergent requests.

Discussion

Summer Temperature and Drought Forecasts

Peak electricity demand in most areas is directly influenced by temperature. Weather officials are expecting above normal temperatures for much of the United States while Canada is largely expected to see normal or below-normal average temperatures (see **Figure 2**). In addition, drought conditions continue across much of the western half of North America, resulting in unique challenges to area electricity supplies and potential impacts on demand.[6] Assessment area load forecasts account for many years of historical demand data, often up to 30 years, to predict summer peak demand and prepare for more extreme conditions. Above average seasonal temperatures can contribute to high peak demand as well as an increase in forced outages for generation and some BPS equipment. Effective preseason maintenance and preparations are particularly important to BPS reliability in severe or prolonged periods of above-normal temperatures.

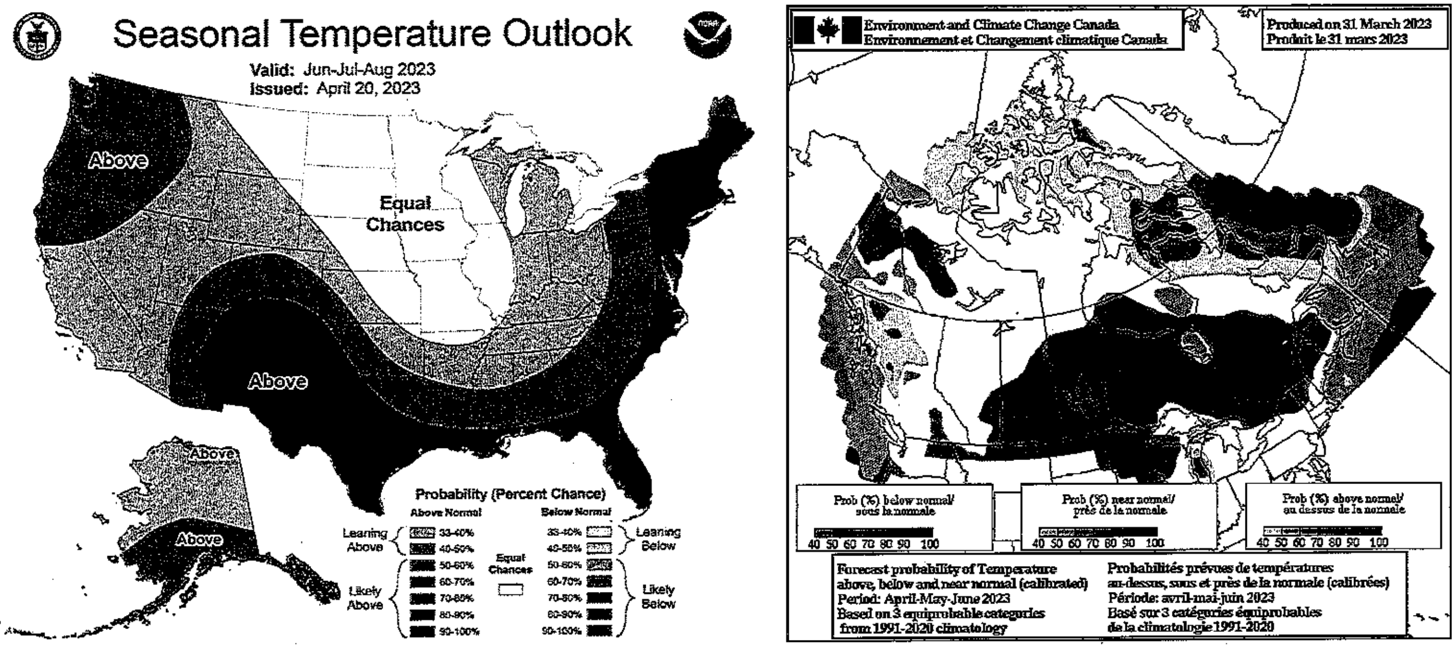


Figure 2: United States and Canada Summer Temperature Outlook[7]

[6] See North American Drought Monitor: https://www.ncdc.noaa.gov/temp-and-precip/drought/nadm/maps

[7] Seasonal forecasts obtained from U.S. National Weather Service and Natural Resources Canada: https://www.cpc.ncep.noaa.gov/products/predictions/long_range/ and https://weather.gc.ca/saisons/prob_e.html

Wildfire Risk Potential and BPS Impacts

Normal or below-normal fire risk is projected for much of the U.S. West at the beginning of the summer; in contrast, Florida, West Texas, and Central Canada project above-normal fire risks for the beginning of summer (see **Figure 3**). BPS operation can be impacted in areas where wildfires are active as well as areas where there is heightened risk of wildfire ignition due to weather and ground conditions. Above normal fire risk is projected for much of Canada throughout the summer.

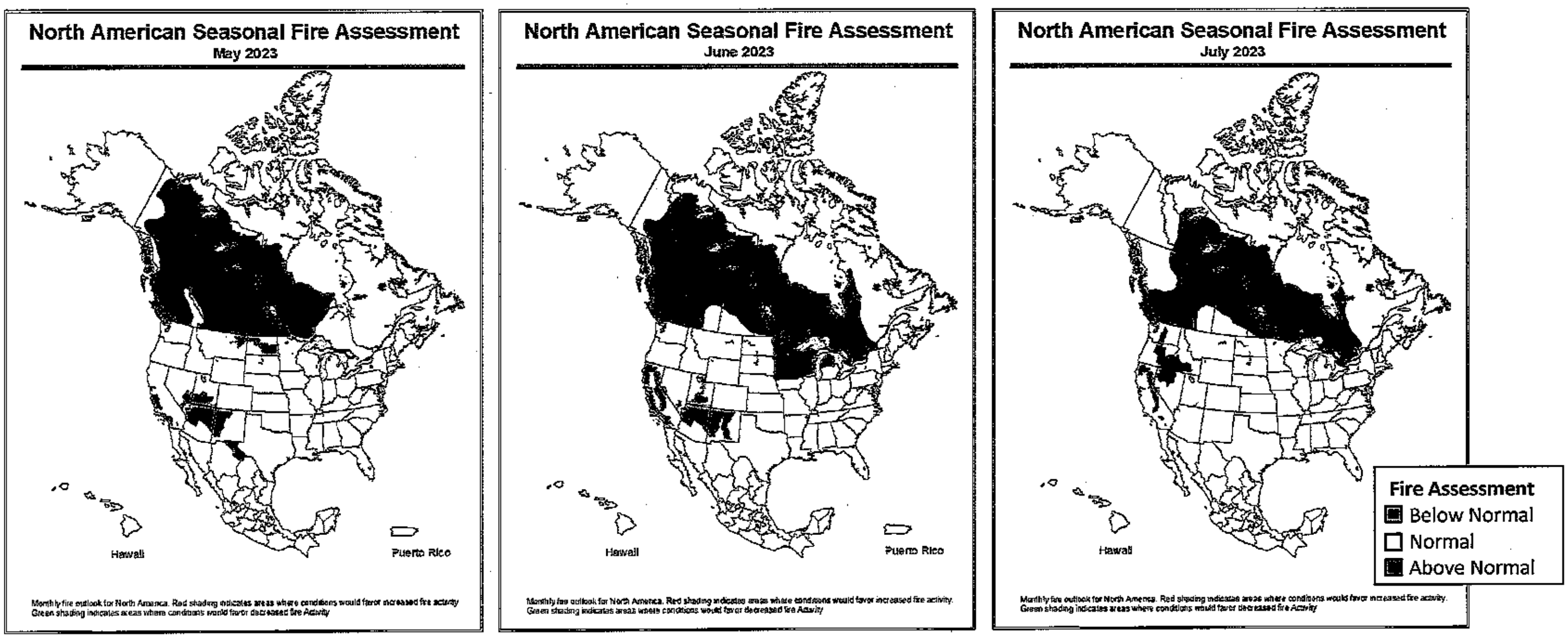


Figure 3: North American Seasonal Fire Assessment for May through July 2023[8]

Wildfire prevention planning in California and some states in the U.S. Northwest include power shut-off programs in high fire-risk areas. When conditions warrant implementing these plans, power lines (including transmission-level lines) may be preemptively de-energized in high fire-risk areas to prevent wildfire ignitions. Other wildfire risk mitigation activities include implementing enhanced vegetation management, equipment inspections, system hardening, and added situational awareness measures. In January 2021, the ERO published the *Wildfire Mitigation Reference Guide*[9] to promote preparedness within the North American electric power industry and share the experiences and practices from utilities in the Western Interconnection.

[8] *See North American Seasonal Fire Assessment and Outlook*, May 2023. Subsequent updates at this link will include August and September: https://www.predictiveservices.nifc.gov/outlooks/NA_Outlook.pdf
[9] See the NERC *Wildfire Mitigation Reference Guide*, January 2021: https://nerc.com/comm/RSTC/Documents/Wildfire%20Mitigation%20Reference%20Guide_January_2021.pdf

Risk Assessments of Resource and Demand Scenarios

Seasonal risk scenarios for each assessment area are presented in the **Regional Assessments Dashboards** section. The on-peak reserve margin and seasonal risk scenario chart in each dashboard provide potential summer peak demand and resource condition information. The reserve margins on the right side of the dashboard pages provide a comparison to the previous year's assessment. The seasonal risk scenario charts present deterministic scenarios for further analysis of different demand and resource levels with adjustments for normal and extreme conditions. The assessment areas determined the adjustments to capacity and peak demand based on methods or assumptions that are summarized in the seasonal risk scenario charts; see the **Data Concepts and Assumptions** for more information about these dashboard charts.

The seasonal risk scenario charts can be expressed in terms of reserve margins: In **Table 1**, each assessment area's Anticipated Reserve Margins are shown alongside the reserve margins for a typical generation outage scenario (where applicable) and the extreme demand and resource conditions in their seasonal risk scenario.

Highlighted in orange are the areas identified as having resource adequacy or energy risks for the summer in the **Key Findings** section's discussion. The typical outages reserve margin is comprised of anticipated resources minus the capacity that is likely to be in maintenance or forced outage at peak demand. If the typical maintenance or forced outage margin is the same as the Anticipated Reserve Margin, it is because an assessment area has already factored typical outages into the anticipated resources. The extreme conditions margin includes all components of the scenario and represents the most severe operating conditions of an area's scenario. Note that any reserve margin below zero indicates that the resources fall below demand in the scenario.

In addition to the peak demand and seasonal risk hour scenario charts, the assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the **Probabilistic Assessment** section. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include loss of load expectation (LOLE), loss of load hours (LOLH), expected unserved energy (EUE), and the probabilities of energy emergency alert (EEA) occurrence.

Table 1: Seasonal Risk Scenario On-Peak Reserve Margins

Assessment Area	Anticipated Reserve Margin	Anticipated Reserve Margin with Typical Outages	Anticipated Reserve Margin with Higher Demand, Outages, Derates in Extreme Conditions
MISO	23.0%	4.3%	-6.9%
MRO-Manitoba	29.1%	25.6%	13.1%
MRO-SaskPower	29.1%	12.8%	-1.9%
NPCC-Maritimes	49.7%	39.3%	20.2%
NPCC-New England	17.7%	7.0%	-3.9%
NPCC-New York	30.3%	17.0%	9.9%
NPCC-Ontario	14.0%	14.0%	-8.6%
NPCC-Québec	37.1%	37.1%	37.1%
PJM	31.9%	23.4%	8.4%
SERC-Central	18.0%	9.6%	-6.4%
SERC-East	19.1%	16.0%	9.0%
SERC-Florida Peninsula	26.6%	19.9%	12.8%
SERC-Southeast	39.6%	36.4%	33.8%
SPP	24.6%	14.8%	-4.0%
Texas RE-ERCOT	23.0%	16.5%	-1.6%
WECC-AB	24.8%	21.9%	8.1%
WECC-BC	28.9%	28.8%	-5.4%
WECC-CA/MX	35.0%	29.0%	-11.9%
WECC-NW	28.5%	22.5%	-12.9%
WECC-SW	19.5%	15.8%	-6.8%

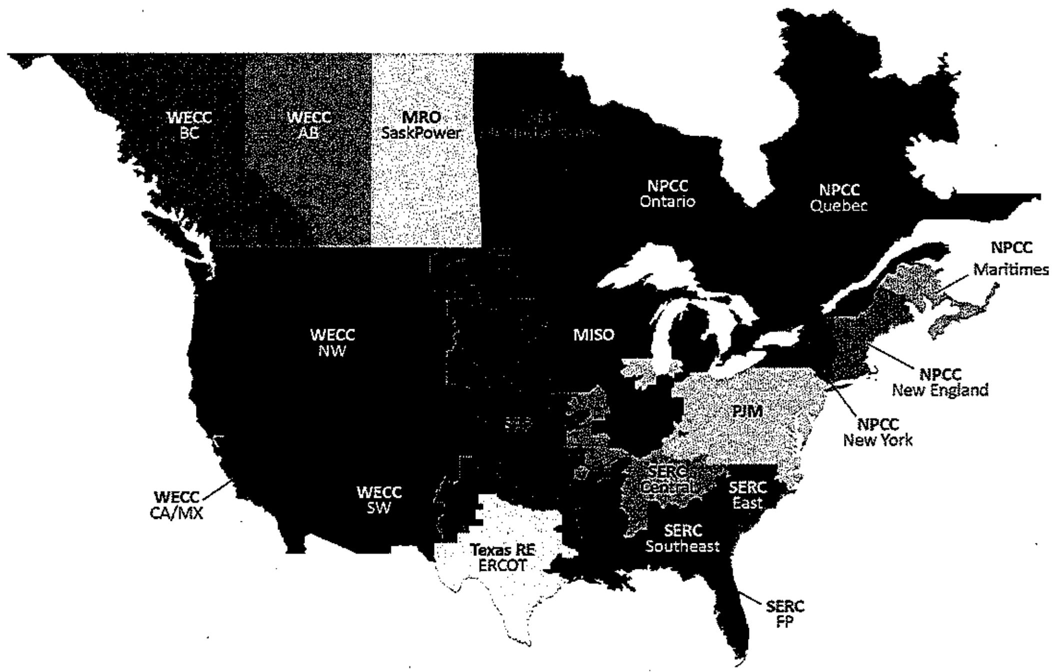
Extreme generation outages, low resource output, and peak loads similar to those experienced in wide area heat events and the heat domes experienced in western parts of North America during the last three summers are ongoing reliability risks in certain areas for the summer of 2023. When forecasted resources in an area fall below expected demand, BAs would need to employ operating mitigations or EEA to obtain the capacity and energy necessary to meet extreme peak demands. **Table 2** describes the various EEA levels and the circumstances for each.

Table 2: Energy Emergency Alert Levels

EEA Level	Description	Circumstances
EEA 1	All available generation resources in use	• The BA is experiencing conditions where all available generation resources are committed to meet firm load, firm transactions, and reserve commitments and is concerned about sustaining its required contingency reserves. • Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.
EEA 2	Load management procedures in effect	• The BA is no longer able to provide its expected energy requirements and is an energy deficient BA. • An energy deficient BA has implemented its operating plan(s) to mitigate emergencies. • An energy deficient BA is still able to maintain minimum contingency reserve requirements.
EEA 3	Firm Load interruption is imminent or in progress	• The energy deficient BA is unable to meet minimum contingency reserve requirements.

Regional Assessments Dashboards

The following assessment area dashboards and summaries were developed based on data and narrative information collected by NERC from the six Regional Entities on an assessment area basis. Guidelines and definitions are in the **Data Concepts and Assumptions** table. On-Peak Reserve Margin bar charts show the Anticipated Reserve Margin compared to a Reference Margin Level that are established for the areas to meet resource adequacy criteria. Prospective Reserve Margins can give an indication of additional on-peak capacity but are not used for assessing adequacy. The operational risk analysis shown in the following regional assessments dashboard pages provides a deterministic scenario for understanding how various factors that affect resources and demand can combine to impact overall resource adequacy. For each assessment area, there is a risk-period scenario graphic; the left blue column shows anticipated resources (from the **Demand and Resource Tables**), and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand (from the **Demand and Resource Tables**) and the extreme summer peak demand determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources. Adjustments may include reductions for typical generation outages (maintenance and forced not already accounted for in anticipated resources) and additions that represent the quantified capacity from operational tools (if any) that are available during scarcity conditions but have not been accounted for in the SRA reserve margins. Resources throughout the scenario are compared against expected operating reserve requirements that are based on peak load and normal weather. The cumulative effects from extreme events are also factored in through additional resource derates or low-output scenarios. In addition, results from a probability-based resource adequacy assessment are shown in the Highlights section of each dashboard. Methods varied by assessment area and provided further insights into the risk conditions forecasted for the summer period.



- MISO *(Midcontinent Independent System Operator)*
- PJM

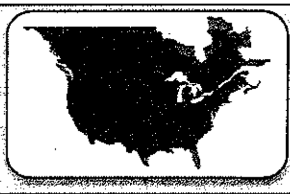
MRO – Midwest Reliability Organization
- MRO-Manitoba Hydro
- MRO-SaskPower
- SPP

NPCC – Northeast Power Coordinating Council
- NPCC-Maritimes
- NPCC-New England
- NPCC-New York
- NPCC-Ontario
- NPCC-Québec

SERC – SERC Reliability Corporation
- SERC-Central
- SERC-East
- SERC-Southeast
- SERC-Florida Peninsula

Texas RE – Texas Reliability Entity
- Texas RE-ERCOT *(Electric Reliability Council of Texas)*

WECC
- WECC-AB *(Alberta)*
- WECC-BC *(British Colombia)*
- WECC-CA/MX *(California/Mexico)*
- WECC-NW *(Northwest)*
- WECC-SW *(Southwest)*



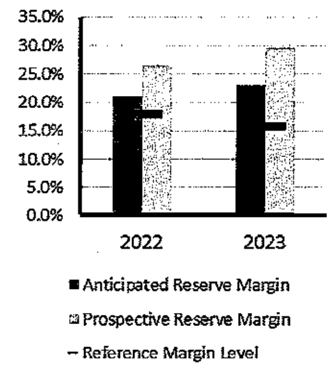
MISO

MISO is a not-for profit, member-based organization that administers wholesale electricity markets that provide customers with valued service; reliable, cost-effective systems and operations; dependable and transparent prices; open access to markets; and planning for long-term efficiency. MISO manages energy, reliability, and operating reserve markets that consist of 36 local BA and 394 market participants, serving approximately 42 million customers. Although parts of MISO fall in three Regional Entities, MRO is responsible for coordinating data and information submitted for NERC's reliability assessments.

Highlights

- Demand forecasts and preliminary resource data indicate that MISO is at risk of operating reserve shortfalls during periods of high demand or low resource output. MISO's resources are projected to be lower than in the summer of 2022 while net internal demand has also decreased. Firm transmission imports for this summer have significantly increased; this has resulted in a higher Anticipated Reserve Margin (ARM) of 23% (on an installed capacity basis) compared to 21% last summer. MISO's capacity auction has not concluded at the time of this assessment, which could lead to some change to MISO's firm resources for the summer.
- MISO conducted its annual probabilistic LOLE analysis and determined a 2023 Reference Margin Level (RML) of 15.9% results in an LOLE of 1 day in 10 years. MISO's RML declined from 17.9% in 2022 to 15.9% in 2023 based on the newly implemented seasonal capacity construct and associated modeling improvements that include seasonal outage rates and other enhancements. Comparing the increased ARM to the lower RML indicates improved reliability from the LOLE base case at 1 day in 10 years.
- Performance of wind generators during periods of high electricity demand is a key factor in determining whether system operators need to employ operating mitigations, such as maximum-generation declarations and energy emergencies. MISO has over 30,300 MW of installed wind capacity; however, the historically-based on-peak capacity contribution is 5,488 MW.

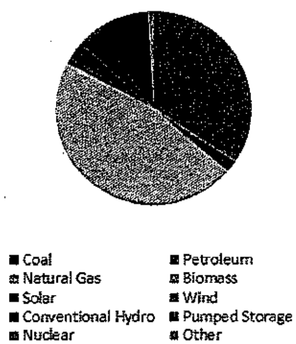
On-Peak Reserve Margin



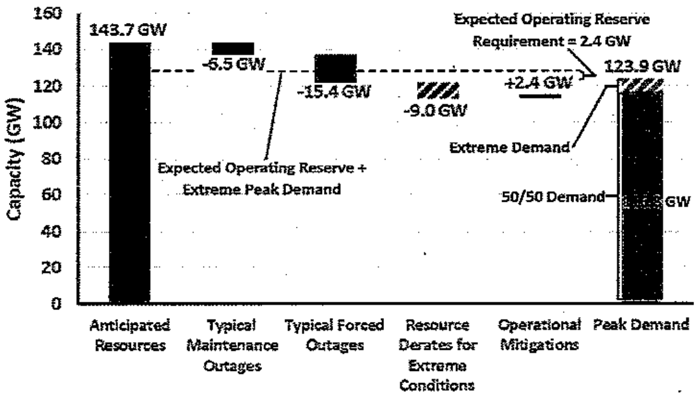
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., load modifying resources and energy transfers from neighboring systems) and EEAs. Emergency declarations that can only be called upon when available generation is at maximum capability are necessary to access load modifying resources (demand response) when operating reserve shortfalls are projected.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

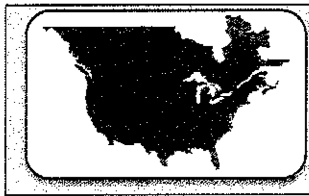
Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast using 30 years of historical data

Maintenance Outages: Rolling five-year summer average of maintenance and planned outages

Forced Outages: Five-year average of all outages that were not planned

Extreme Derates: Maximum historical generation outages

Operational Mitigations: A total of 2.4 GW capacity resources available during extreme operating conditions



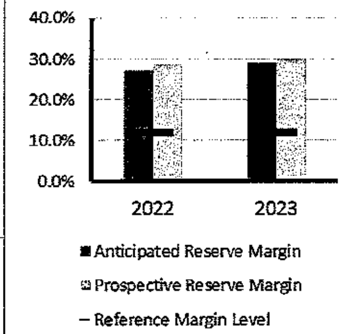
MRO-Manitoba Hydro

Manitoba Hydro is a provincial Crown Corporation and one of the largest integrated electricity and natural gas distribution utilities in Canada. Manitoba Hydro is a leader in providing renewable energy and clean-burning natural gas Manitoba Hydro provides electricity to approximately 608,500 electric customers in Manitoba and provides approximately 293,000 customers with natural gas in Southern Manitoba. The service area is the province of Manitoba which is 251,000 square miles Manitoba Hydro is winter peaking. Manitoba Hydro is its own Planning Coordinator (PC) and BA. Manitoba Hydro is a coordinating member of MISO. MISO is the RC for Manitoba Hydro.

Highlights

- Manitoba Hydro is not anticipating any operational challenges and/or emerging reliability issues in its assessment area for the summer of 2023.
- The Anticipated Reserve Margin for the summer of 2023 exceeds the 12% Reference Margin Level.
- Six of the seven units at Keeyask Generating Station (hydroelectric) have reached commercial operation status. The remaining unit (Keeyask Unit 6) is listed as a Tier 1 capacity resource as it is operating but awaiting official commercial operation status.
- The 2022 probabilistic work indicated the annual probabilistic indices for the Manitoba Hydro system for 2024 of 29 MWh per year of EUE. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023.

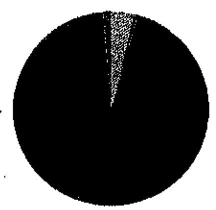
On-Peak Reserve Margin



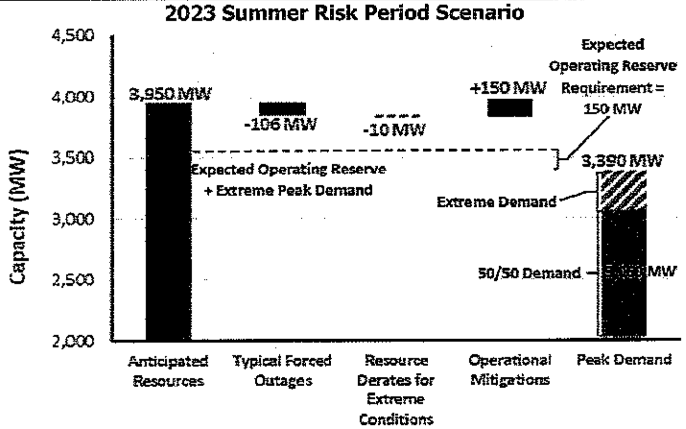
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: (50/50) Demand with allowance for Extreme Demand based on extreme summer weather scenario of 37 C (99 F)

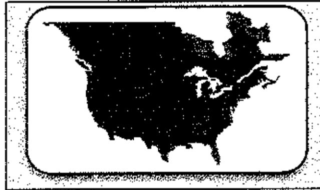
Forced Outages: Typical forced outages

Extreme Derates: Summer wind capacity accreditation of 18.1% of nameplate rating based on MISO seasonal analysis

Normal hydro generation expected for this summer.

Operational Mitigations: Utilize Curtailable Rate Program to manage peak demand; utilize operating reserve if additional measures required

MRO-SaskPower

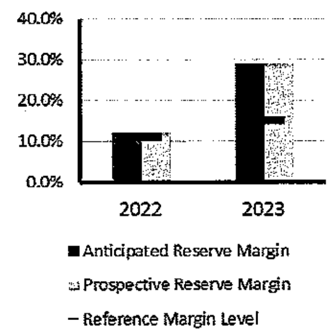


MRO-SaskPower is an assessment area in the Saskatchewan province of Canada. The province has a geographic area of 651,900 square kilometers (251,700 square miles) and a population of approximately 1.1 million. Peak demand is experienced in the winter. The Saskatchewan Power Corporation (SaskPower) is the PC and RC for the province of Saskatchewan and is the principal supplier of electricity in the province. SaskPower is a provincial crown corporation and, under provincial legislation, is responsible for the reliability oversight of the Saskatchewan BES and its interconnections.

Highlights

- Summer reserve margins in Saskatchewan are higher than in 2022 due to the addition of new wind resources, fewer scheduled generator outages, and lower forecasted peak demand.
- Saskatchewan is a winter-peaking region but also experiences high load in summer during extreme hot weather.
- SaskPower conducts an annual summer joint operating study with Manitoba Hydro and prepares operating guidelines for any identified issues. Inputs from the Western Area Power Administration are included in the study.
- Results from SaskPower's probabilistic analysis indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. The month with the highest probability of EEA is September (0.07 hours). The risk of operating reserve shortage during peak load times or EEAs could increase if large generation forced outage combined with planned maintenance outages occurs during peak load times in June, July, August, and September months.
- In case of extreme electricity demand from high temperatures combined with large generation forced outages, SaskPower would use available demand response programs, short-term power transfers from neighboring utilities, and short-term load interruptions if necessary.
- The Reference Reserve Margin was updated to adequately assess energy risks, such as due to changing resource mix, and to align with NERC recommended RRM.

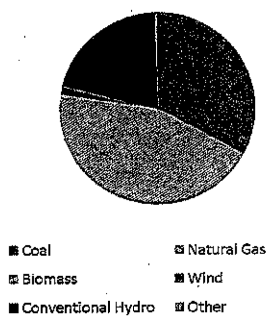
On-Peak Reserve Margin



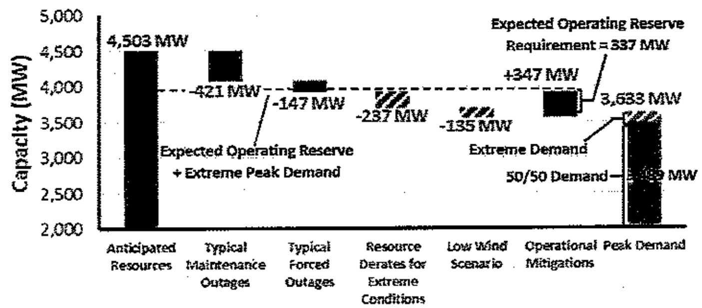
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and above-normal scenario based on peak demand with lighting and all consumer loads

Maintenance Outages: Average of planned maintenance outages for the last three summers less future planned outages (already considered in Anticipated Resources)

Forced Outages: Estimated by using SaskPower forced outage model

Extreme Derates: Estimated resources unavailable in extreme conditions

Low Wind Scenario: 33% reduction in nameplate capacity for temperatures between 35° C and 40° C

Operational Mitigations: Estimated non-firm imports and stand-by generators on 2–7 day notice

NPCC-Maritimes

The Maritimes assessment area is a winter-peaking NPCC area that contains two BAs. It is comprised of the Canadian provinces of New Brunswick, Nova Scotia, and Prince Edward Island, and the northern portion of Maine, which is radially connected to the New Brunswick power system. The area covers 58,000 square miles with a total population of 1.9 million.

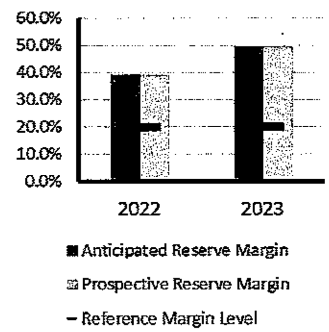
Highlights

- The Maritimes area has not identified any operational issues that are expected to impact system reliability. If an event were to occur, there are emergency operations and planning procedures in place. All of the area's declared firm capacity is expected to be operational for the summer. As part of the planning process, dual-fuel units will have sufficient supplies of heavy fuel oil on-site to enable sustained operation in the event of natural gas supply interruptions.
- Based on an NPCC Probabilistic Assessment, minimal amounts of cumulative LOLE (<0.03 days/period), LOLH (<0.11 hours/period), or EUE (<5 MWh/period) were estimated over the May–September summer period for all modeled scenarios. The Maritimes area is winter peaking. The analysis included simulation of a base case (normal 50/50 demand and expected resources) and a highest peak load scenario as well as a low-likelihood, reduced resource case. This reduced resource case considered the impacts of wind capacity being derated by half during July and August due to calm weather, natural-gas-fired units being derated by half in July and August due to supply disruptions (dual-fuel units assumed to revert to oil) as well as reduced transfer capabilities. The highest load level results were based on the two highest load levels of the seven modeled, having approximately a combined 7% chance of occurring.

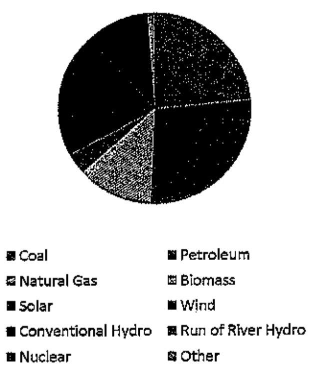
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs.

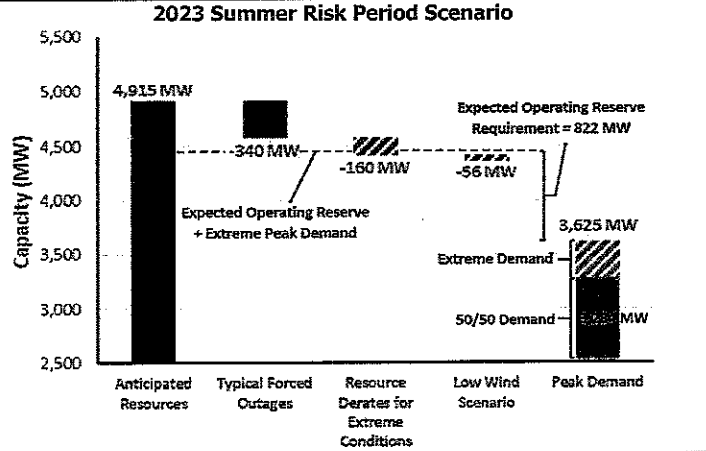
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (above 90/10) extreme demand forecast

Forced Outages: Based on historical operating experience

Extreme Derates: A low-likelihood scenario resulting in an additional 50% derate in the remaining capacity of both natural gas and wind resources under extreme conditions

NPCC-New England

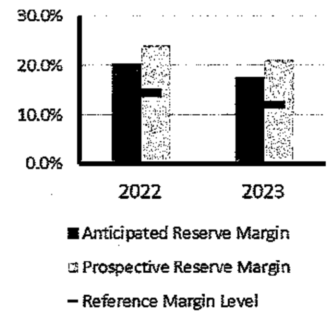
NPCC-New England is an assessment area consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont that is served by ISO New England (ISO-NE) Inc. ISO-NE is a regional transmission organization that is responsible for the reliable day-to-day operation of New England's bulk power generation and transmission system, administration of the area's wholesale electricity markets, and management of the comprehensive planning of the regional BPS.

The New England BPS serves approximately 14.5 million customers over 68,000 square miles.

Highlights

- Reserve margins in New England are projected to be lower this summer due to less existing-certain capacity and firm imports. The New England area expects to have sufficient capacity to meet the 2023 summer peak demand forecast. As of April 4, 2023, The New England area expects to have sufficient resources to meet the 2023 summer peak demand forecast of 24,664 MW, for the weeks beginning June 4 through week beginning September 10, 2023, with the lowest projected net margin of 231 MW (0.9%) during the week of June 25, 2023. The 2023 summer demand forecast takes into account the demand reductions associated with energy efficiency, load management, behind-the-meter photovoltaic (BTM-PV) systems, and distributed generation.
- Based on an NPCC Probabilistic Assessment, ISO-NE may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

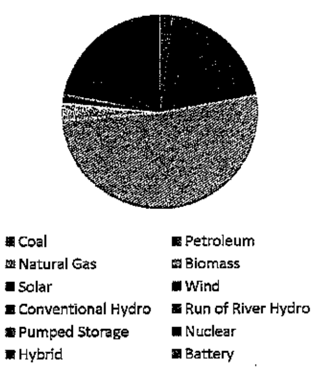
On-Peak Reserve Margin



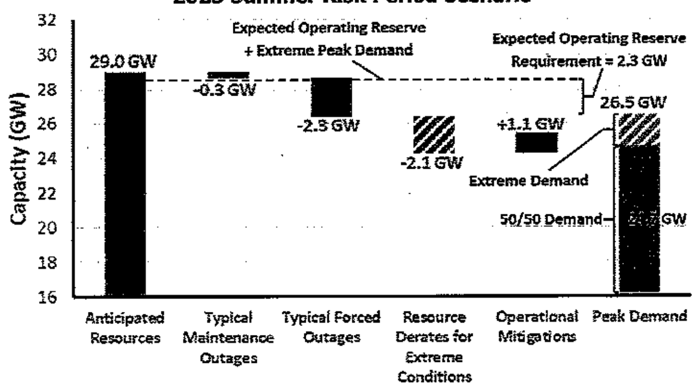
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios with local operating procedures. Extreme summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response, transfers, appeals) and EEAs. As noted above, the risk of load shedding is low.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Peak net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance & Forced Outages: Based on historical weekly averages

Extreme Derates: Represent a case that is beyond the (90/10) conditions based on historical observation of force outages, additional reductions for generation at risk due to operating issues at extreme hot temperatures, and other outage causes reported by generators

Operational Mitigations: Based on load and capacity relief assumed available from invocation of ISO-NE operating procedures

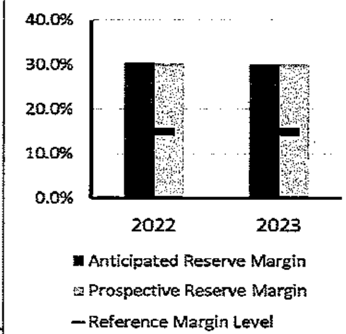
NPCC-New York

NPCC-New York is an assessment area consisting of the New York ISO (NYISO) service territory. NYISO is responsible for operating New York's BPS, administering wholesale electricity markets, and conducting system planning. The NYISO is the only BA within the state of New York. The BPS encompasses over 11,000 miles of transmission lines, 760 power generation units, and serves 20.2 million customers. For this SRA, the established Reference Margin Level is 15%. Wind, grid-connected solar PV, and run-of-river totals were derated for this calculation. However, New York requires load-serving entities to procure capacity for their loads equal to their peak demand plus an Installed Reserve Margin (IRM). The IRM requirement represents a percentage of capacity above peak load forecast and is approved annually by the New York State Reliability Council. New York State Reliability Council approved the 2022–2023 IRM at 20.0%.

Highlights

- NYISO is not anticipating any operational issues in the New York control area for the upcoming summer. Adequate capacity margins are anticipated, and existing operating procedures are sufficient to handle any issues that may occur.
- A number of combustion turbine generators will be retiring before or during this summer as a result of the New York State Department of Environmental Conservation Peaker Rule. Retirements in 2023 include 16 MW of natural-gas-fired, 53 MW of oil-fired, and 558 MW of dual-fueled generation. New generation includes 556 MW of land-based wind, 90 MW of new solar PV (coming in the third quarter), and 136 MW of new offshore wind generation (coming in the third quarter). Overall, the rule is expected to lead to the retirement of approximately 1,600 MW of capacity by 2025.
- Based on an NPCC Probabilistic Assessment, NYISO may rely on limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood case. This reduced resource case with highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/period) with associated LOLH (1.1 hours/period) and EUE (525 MWh/period) with the highest risk in June and August. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.

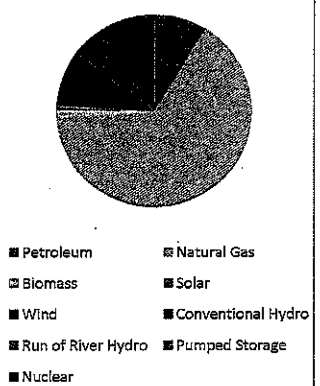
On-Peak Reserve Margin



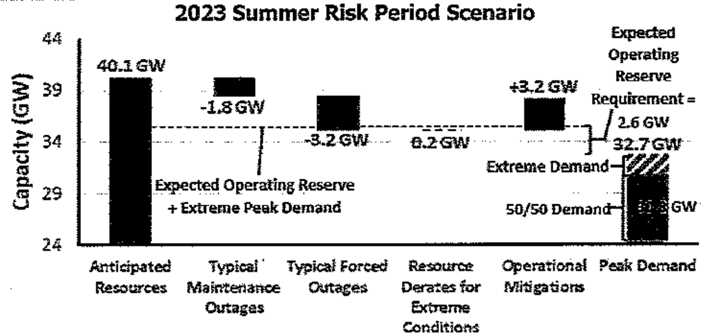
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) extreme demand forecast

Maintenance Outages:

Forced Outages: Based on historical 5-year averages

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.3 GW based on operational/emergency procedures in area emergency operations manual

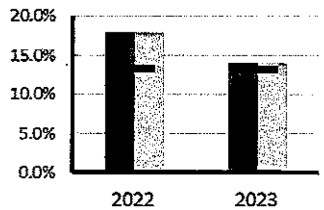
NPCC-Ontario

NPCC-Ontario is an assessment area in the Ontario province of Canada. The Independent Electricity System Operator (IESO) is the BA for the province of Ontario. The province of Ontario covers more than 1 million square kilometers (415,000 square miles) and has a population of more than 14 million. Ontario is interconnected electrically with Québec, MRO-Manitoba, states in MISO (Minnesota and Michigan), and NPCC-New York.

Highlights

- Ontario has entered a period during which generation and transmission outages will be increasingly difficult to accommodate. The IESO expects these conditions to persist for the foreseeable future. IESO is strongly encouraging market participants to plan ahead and coordinate with IESO to ensure planned outages can be appropriately scheduled.
- Under both normal and extreme weather conditions, Ontario may rely on imports and outage management for a significant number of weeks during the 2023 summer assessment period primarily as a result of coincident generator outages. Should market participants be unable to reschedule certain outages during this period, Ontario may have to rely on more than 2,000 MW of non-firm supply from other areas and/or additional operating actions to ensure reliability.
- Based on an NPCC Probabilistic Assessment, Ontario is expected to need only limited use of its operating procedures that are designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios except the severe low-likelihood cases, which resulted in small LOLH (0.3 hours). These results model import availability and indicate that Ontario will be able to obtain the necessary supplies from neighbors over a range of most conditions, but there is a risk during extreme demand and low resource periods.
- The ongoing transmission outage at the New York–St. Lawrence interconnection continues to impact import and export capacity between Ontario and New York. This issue is expected to be resolved by the end of the fourth quarter of 2023.

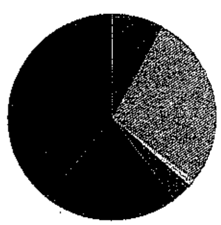
On-Peak Reserve Margin



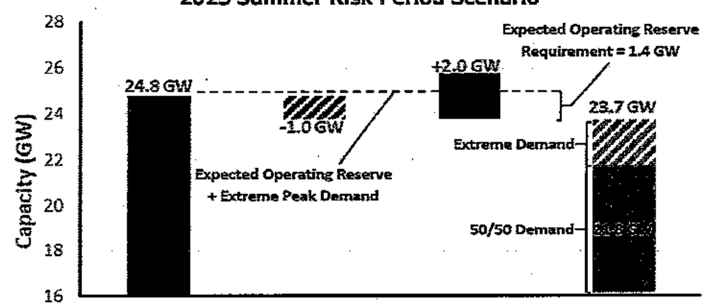
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load or extreme outage conditions could result in the need to employ operating mitigations (i.e., demand response and non-firm transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50 Forecast) and highest weather-adjusted daily demand based on 31 years of demand history

Extreme Derates: Derived from weather-adjusted temperature rating of thermal units and adjustments to expected hydro production for low water conditions

Operational Mitigations: Imports anticipated from neighbors during emergencies

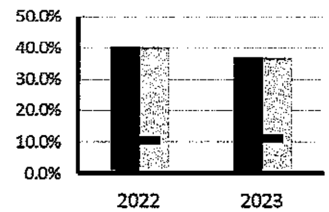
NPCC-Québec

The Québec assessment area (Province of Québec) is a winter-peaking NPCC area that covers 595,391 square miles with a population of 8 million. Québec is one of the four Interconnections in North America; it has ties to Ontario, New York, New England, and the Maritimes; consisting of either high voltage direct current ties, radial generation, or load to and from neighboring systems.

Highlights

- The Québec area forecasted summer peak demand (excluding April, May, and September) is 22,859 MW during the week of August 13, 2023, with a forecasted net margin of 7,202 MW (31.5%). No particular resource adequacy problems are forecasted, and the Québec area expects to be able to provide assistance to other areas up to the transfer capability available.
- In the Québec RC area, most transmission line, transformer, and generating unit maintenance is done during the summer period. Internal transmission outage plans are assessed to meet internal demand, firm sales, expected additional sales, and additional uncertainty margins. They should not impact inter-area transfer capabilities with neighboring systems. During the 2023 summer operating period, some maintenance outages are scheduled on the interconnections. Maintenance is coordinated with neighboring RC areas so as to leave maximum capability to summer-peaking areas.
- Based on an NPCC Probabilistic Assessment, Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.

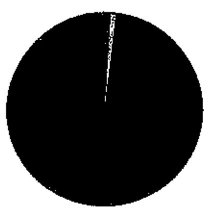
On-Peak Reserve Margin



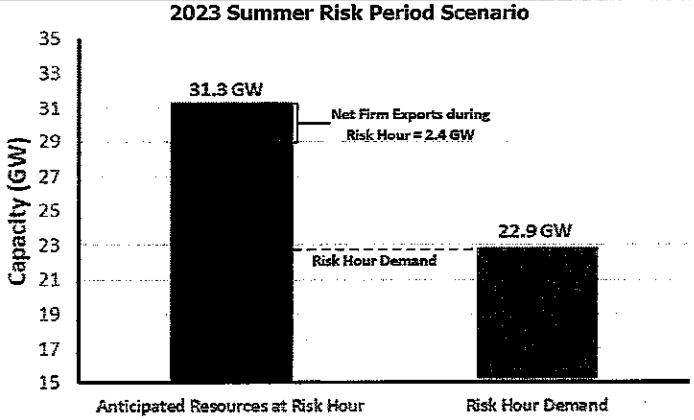
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario

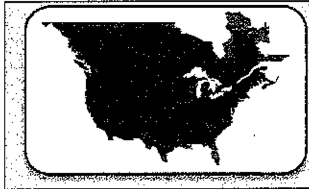


Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenario: Net internal demand (50/50) and (90/10) demand forecast

Net Firm Transfers: Anticipated exports to neighbors during the risk hour



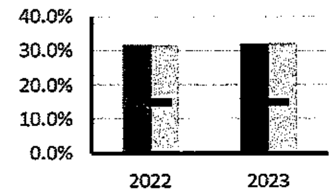
PJM

PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM serves 65 million customers and covers 369,089 square miles. PJM is a BA, PC, Transmission Planner, Resource Planner, Interchange Authority, TOP, Transmission Service Provider, and RC.

Highlights

- PJM expects no resource problems over the entire 2023 summer peak season. Installed capacity is over twice the PJM reserve requirement necessary to meet the 1-day-in-10-years LOLE criterion.
- The 2022 PJM reserve requirement study used to establish the target installed reserve margin of 14.9% analyzed a wide range of load scenarios (low, regular and extreme) as well as multiple scenarios for system-wide unavailable capacity due to forced outages, maintenance outages, and ambient derations. Due to the rather low penetration of limited and variable resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted net peak demand.
- No other reliability issues are expected.

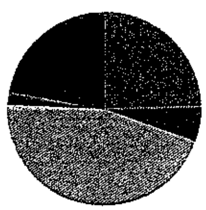
On-Peak Reserve Margin



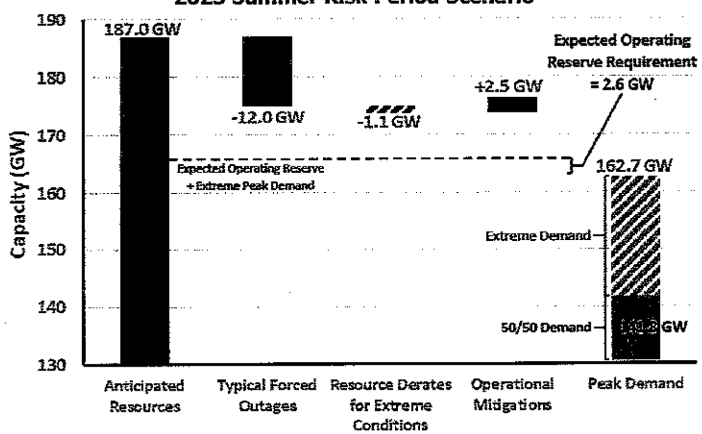
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Based on historical data and trending

Extreme Derates: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 2.5 GW based on operational/emergency procedures

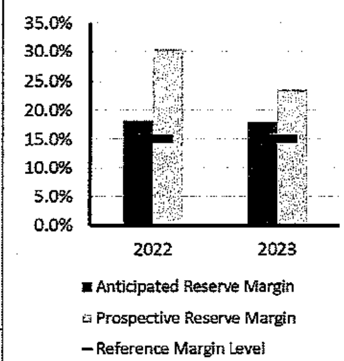
SERC-Central

SERC-Central is an assessment area within the SERC Regional Entity. SERC-Central includes all of Tennessee and portions of Georgia, Alabama, Mississippi, Missouri, and Kentucky. Historically a summer-peaking area, SERC-Central is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under Federal Energy Regulatory Commission (FERC) approved delegation agreements with NERC. SERC-Central is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities (PA), and 6 RCs.

Highlights

- Entities in SERC-Central have not identified any potential reliability issues for the upcoming summer season. Entities anticipate having adequate system capacity for the upcoming summer season and are equipped to address unexpected short-term issues by leveraging diverse generation portfolios and spot purchases from the power markets when necessary.
- Non-economic dispatch (out of merit) of available coal-fired generators ahead of the upcoming summer season is anticipated in order to build inventory and limit consumption of fuel and consumables for plant operations and mitigate supply and transportation challenges during the summer.
- Each entity continues to work collaboratively to ensure reliability for its area within SERC and to promote reliability and adequacy across the entire SERC Regional Entity.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups among others. These working groups help the entities identify and address emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels.

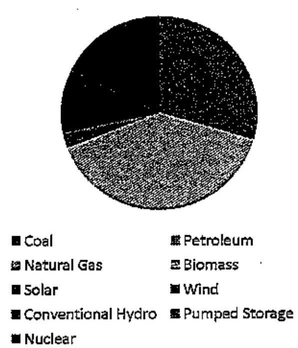
On-Peak Reserve Margin



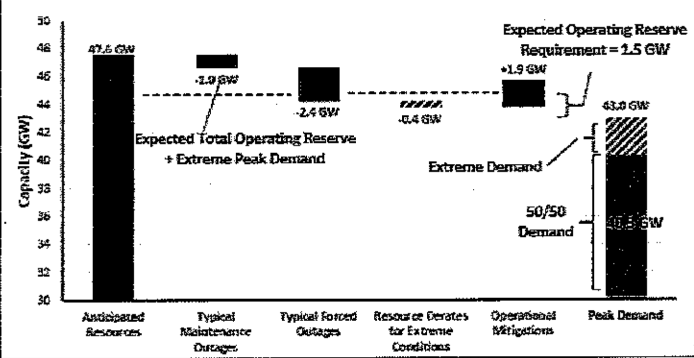
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 1.9 GW based on operational/emergency procedures

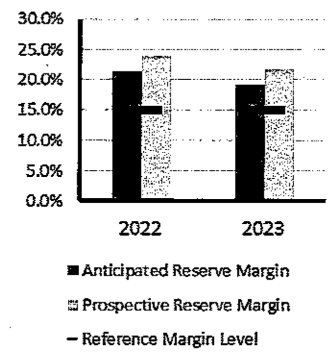
SERC-East

SERC-East is an assessment area within the SERC Regional Entity. SERC-East includes North Carolina and South Carolina. Historically a summer-peaking area, SERC-East is beginning to have higher peak demand forecasts in winter. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

Highlights

- SERC-East is transitioning to a hybrid-peaking (both summer and winter peaking) area as solar PV reduces summer peak demand and electrification of heating drives up winter peak demand.
- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain reliability to the system.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis shows a low risk for resource shortfall during the months of July and August. The 2022 study found LOLH of 0.005 hours and EUE of 2.381 MWh during summer months for a similar resource mix and demand levels.

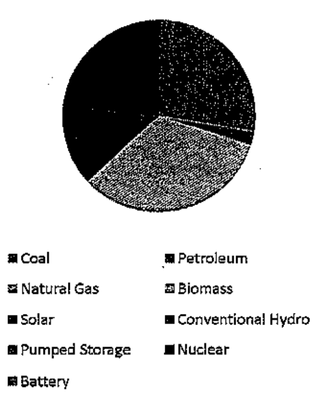
On-Peak Reserve Margin



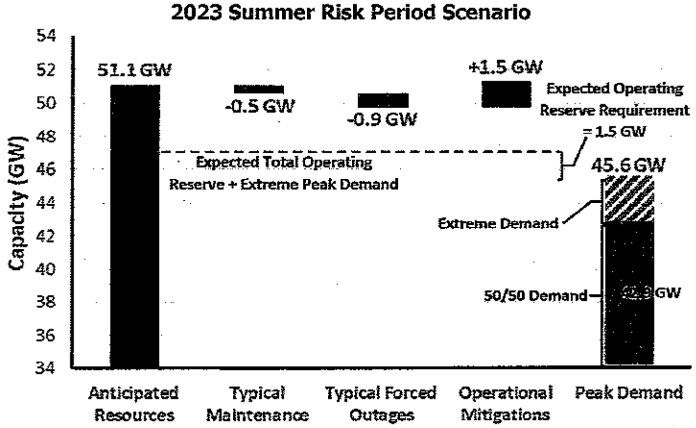
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

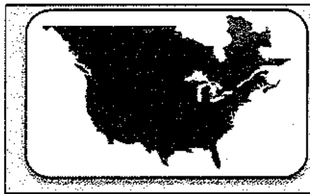
Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 1.5 GW based on operational/emergency procedures



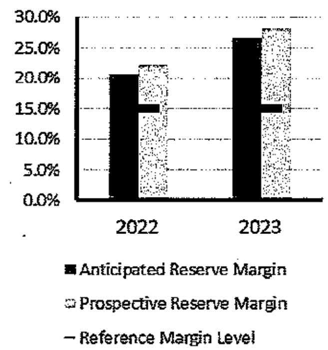
SERC-Florida Peninsula

SERC-Florida Peninsula is a summer-peaking assessment area within SERC. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the Southeastern and Central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 PAs, and 6 RCs.

Highlights

- Entities have not identified any emerging reliability issues or operational concerns for the upcoming summer season.
- Entities continue to perform resource studies to ensure resource adequacy to meet the summer peak demand and to maintain system reliability.
- Entities continue to participate actively in the SERC Near-Term and Long-Term Working Groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- SERC probabilistic analysis indicates negligible risk for resource shortfall. The 2022 study found negligible LOLH and EUE during summer months for a similar resource mix and demand levels

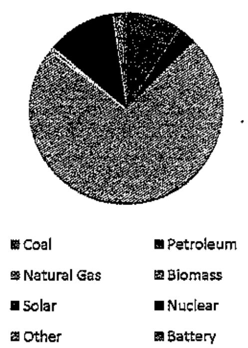
On-Peak Reserve Margin



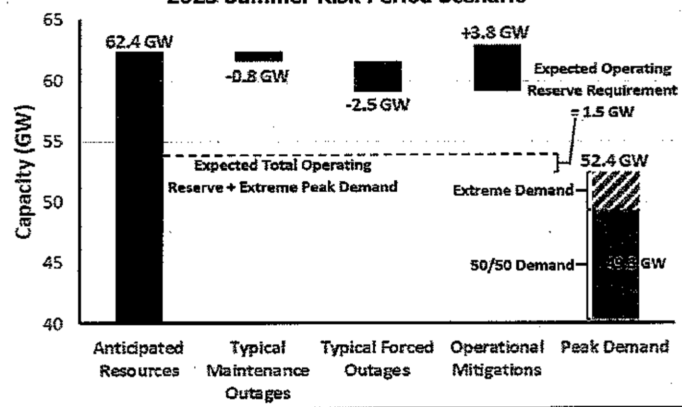
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Operational Mitigations: A total of 3.8 GW based on operational/ emergency procedures

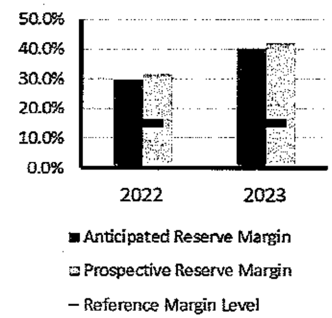
SERC-Southeast

SERC-Southeast is a summer-peaking assessment area within the SERC Regional Entity. SERC-Southeast includes all or portions of Georgia, Alabama, and Mississippi. SERC is one of the six companies across North America that are responsible for the work under FERC approved delegation agreements with NERC. SERC is specifically responsible for the reliability and security of the electric grid across the southeastern and central areas of the United States. This area covers approximately 630,000 square miles and serves a population of more than 91 million. The SERC Regional Entity includes 36 BAs, 28 Planning Authorities, and 6 RCs.

Highlights

- Entities have not identified any emerging reliability issues for the upcoming summer season that will impact resource adequacy.
- The available system capacity for the upcoming summer season meets or exceeds the reserve margin target. Reliability is supported by a diverse fuel mix, firm natural gas contracts, and power purchases.
- Entities continue to participate actively in the SERC near-term and long-term working groups. These groups identify emerging and potential reliability impacts on transmission and resource adequacy along with transfer capability.
- Probabilistic analysis indicates almost no risk for resource shortfall.

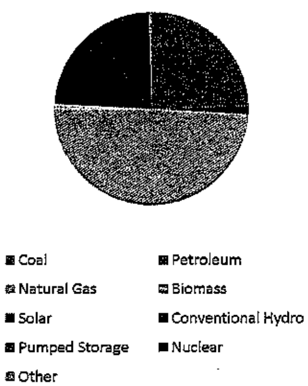
On-Peak Reserve Margin



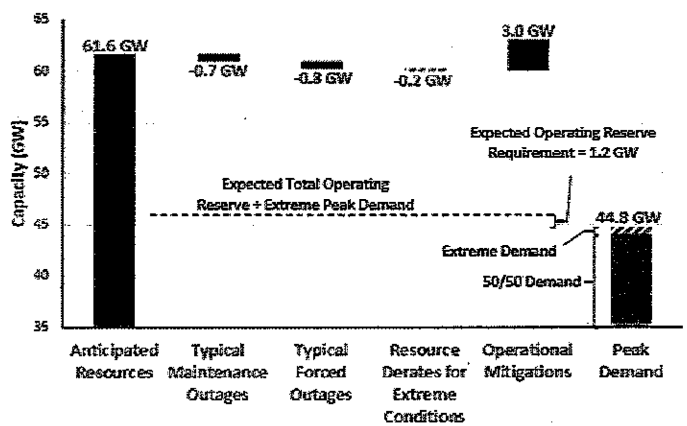
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand forecast based on extreme summer weather (equals or exceeds the (90/10) demand forecast)

Maintenance Outages: Adjusted for higher outages resulting from extreme summer temperatures and aggregated on a SERC subregional level

Forced Outages: Accounts for reduced thermal capacity contributions due to performance in extreme conditions

Extreme Derates: Estimated resources unavailable in extreme conditions

Operational Mitigations: A total of 3.0 GW based on operational/ emergency procedures

SPP

SPP PC footprint covers 546,000 square miles and encompasses all or parts of Arkansas, Iowa, Kansas, Louisiana, Minnesota, Missouri, Montana, Nebraska, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wyoming. The SPP long-term assessment is reported based on the Planning Coordinator footprint, which touches parts of the Midwest Reliability Organization Regional Entity and the WECC Regional Entity. The SPP assessment area footprint has approximately 61,000 miles of transmission lines, 756 generating plants, and 4,811 transmission-class substations, and it serves a population of more than 18 million.

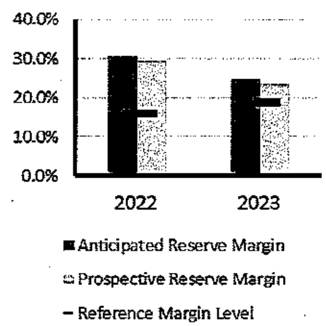
Highlights

- At this time, SPP projects a low likelihood of any emerging reliability issues impacting the area for the 2023 summer season.
- BA generation capacity deficiency risks remain depending on wind generation output levels and unanticipated generation outages in combination with high load periods.
- SPP performed a statistical analysis of risk of energy emergencies for the upcoming summer based on historical data. They found it likely that operators would use part of the 2 GW operating reserves and issue EEA1 and EEA2 level approximately one day each summer; it is likely that operators would deplete all operating reserves approximately once every five summers, resulting in an EEA3.
- Using the current operational processes and procedures, SPP will continue to assess the needs for the 2023 summer season and will adjust as needed to ensure that real-time reliability is maintained throughout the summer time frame.

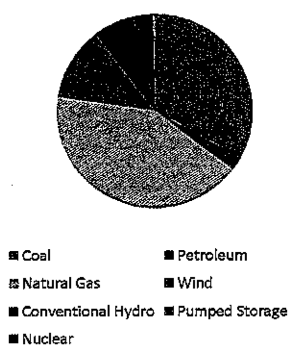
Risk Scenario Summary

Expected resources are sufficient to meet operating reserve requirements under normal peak-demand and outage scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e. demand response and transfers from neighboring systems) and EEAs.

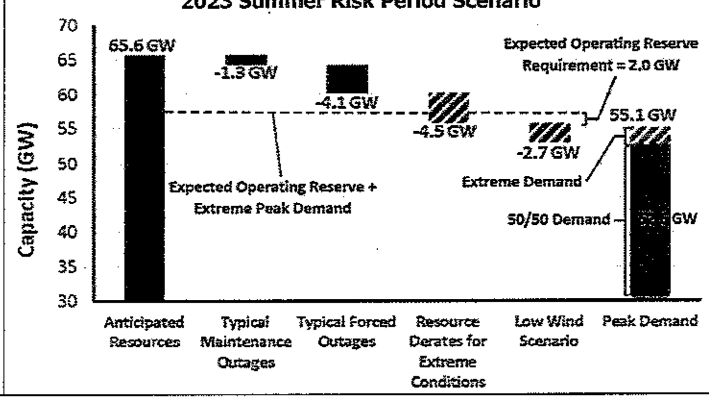
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and extreme demand is a 5% increase from net internal demand

Maintenance & Forced Outages: Represent 5-year historical averages; calculated from SPP's generation assessment process

Extreme Derates: Additional unavailable capacity from operational data at high demand periods

Low Wind Scenario: Derates reflecting a low-wind day in the summer

Texas RE-ERCOT

The Electric Reliability Council of Texas (ERCOT) is the ISO for the ERCOT Interconnection and is located entirely in the state of Texas; it operates as a single BA. It also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for nearly 8 million premises in competitive choice areas. ERCOT is governed by a board of directors and subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. ERCOT is summer-peaking. It covers approximately 200,000 square miles, connects over 52,700 miles of transmission lines, has over 1,100 generation units, and serves more than 26 million customers. Texas RE is responsible for the RE functions described in the Energy Policy Act of 2005 for ERCOT. On November 3, 2022, the Public Utility Commission of Texas issued an order directing ERCOT to assume the duties and responsibilities of the Reliability Monitor for the Texas power grid.

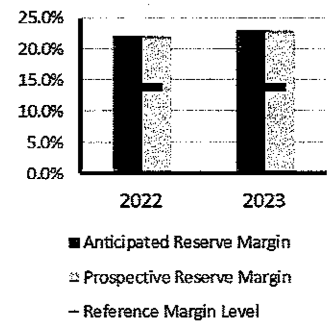
Highlights

- Given an Anticipated Reserve Margin of 23% and Reference Reserve Margin of 13.75%, ERCOT expects to have sufficient operating reserves in expected normal summer system conditions.
- Solar PV nameplate capacity expected for the 2023 summer season is 4.4 GW higher than the forecast amount reported for the 2022 SRA.
- Several generator owners in the ERCOT area indicated they could run out of NOx emission allowances by July 2023 under U.S. EPA's Good Neighbor Plan. Texas filed a motion to stay the EPA's regulatory action. A delay in implementation has alleviated these concerns. ERCOT's probabilistic risk assessment indicates a low probability of energy emergency conditions during the summer peak load period, but the risk increases into the early evening hours due reductions of solar PV generation. There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour increasing up to 19% probability at the highest risk hour ending at 8:00 p.m.
- System stability and strength stemming from the growth of IBRs remains a concern. ERCOT is also experiencing large increases in renewable production curtailments due to transmission constraints, and these curtailments are increasingly occurring at solar PV sites.

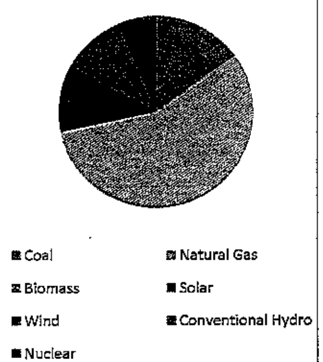
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal and extreme peak-demand scenarios. Extreme generator outages combined with low-wind output during extreme peak demand could result in the need to employ operating mitigations such as demand response, EEAs, and localized load shedding.

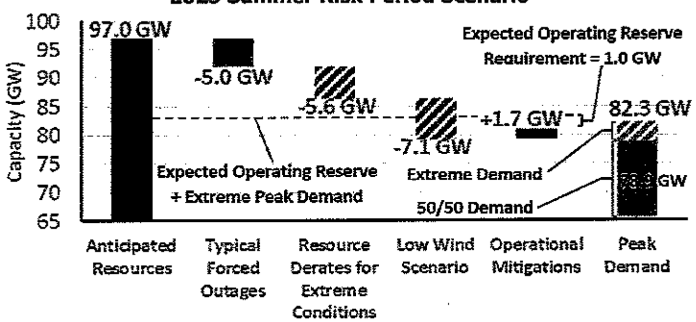
On-Peak Reserve Margin



On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

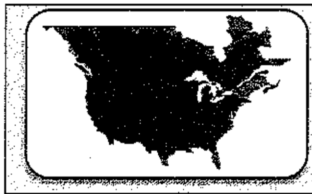
Demand Scenarios: Net internal demand (50/50) and extreme demand represents weather conditions 2% worse than summer peak in 2011

Forced Outages: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last three (2019–2021) summer seasons

Low Wind Scenario: Based on the 10th percentile of historical averages of hourly wind for June through September, hours ending 1:00–9:00 p.m. local time

Extreme Derates: Based on the 95th percentile of historical averages of forced outages for June through September weekdays, hours ending 3:00–8:00 p.m. local time for the last five (2019–2021) summer seasons

Operational Mitigations: Additional capacity from switchable generation and additional imports



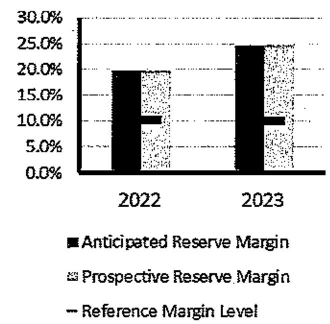
WECC-AB

WECC-AB (Alberta) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of Alberta, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- There is 35% less coal-fired generator capacity in Alberta compared to last summer (446 MW). Resource additions include 554 MW of natural-gas-fired generation, 336 MW of new solar PV resources, and 1,350 MW of new wind generation.
- Based on a WECC Probabilistic Assessment, the WECC-AB assessment area had negligible LOLH and EUE.
- Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

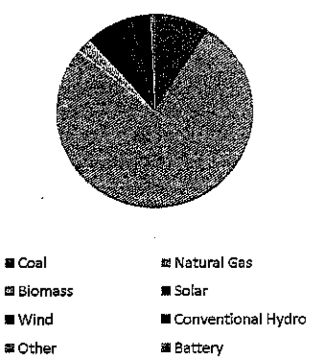
On-Peak Reserve Margin



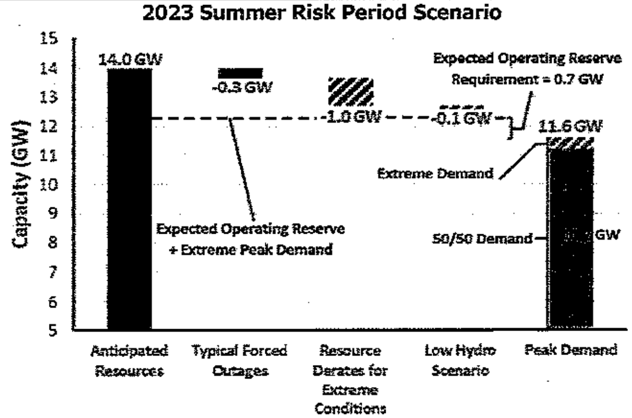
Risk Scenario Summary

Expected resources meet operating reserve requirements under the assessed scenarios

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Typical Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) point of resource performance distribution

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

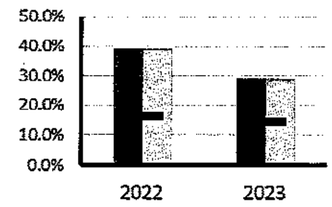
WECC-BC

WECC-British Columbia (BC) is a winter-peaking assessment area in the WECC Regional Entity that consists of the province of British Columbia, Canada. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- BC shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-BC assessment area had negligible LOLH and EUE.
- BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m., under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

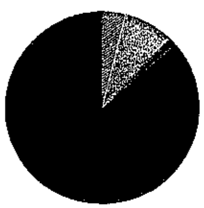
On-Peak Reserve Margin



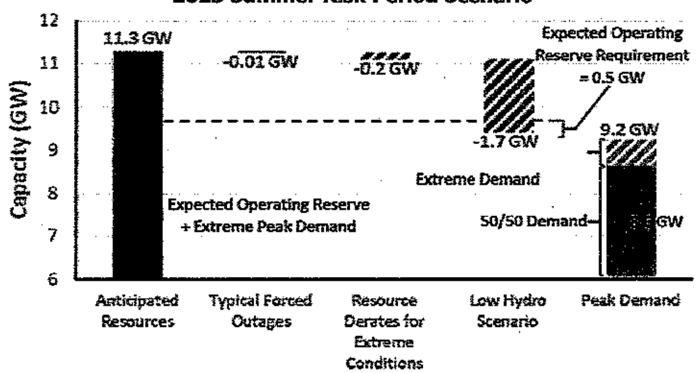
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under the extreme peak demand and outage scenarios studied.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at peak demand hour

Demand Scenarios: Net internal demand (50/50) and (90/10) demand forecast

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) resource performance distribution at peak hour

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

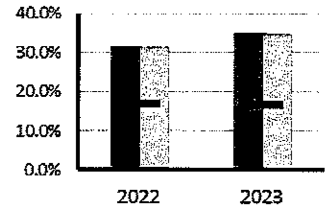
WECC-CA/MX

WECC-CA/MX is a summer-peaking assessment area in the WECC Regional Entity that includes parts of California, Nevada, and Baja California, Mexico. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- CA/MX shows adequate reserve margins under expected conditions on the peak hour. However, increased risk occurs during the hours after peak demand and into the evening due to the variability of energy availability. CA/MX is typically reliant on imports during these periods.
- Based on a WECC Probabilistic Assessment, WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer. Variation in LOLH is attributable to the amount of Tier 1 resources that connect before the later months.
- CA/MX is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.
- For the peak riskiest hour ending 8:00 pm (four hours later than the peak) under an extreme summer peak load, CA/MX would need to rely on increased imports to maintain adequate reserves. Under expected net internal demand for the same riskiest hour (not an extreme summer peak for that hour), any of the typical outages or extreme derates would also cause a need for increased reliance on imports.

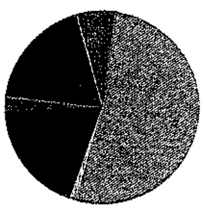
On-Peak Reserve Margin



Risk Scenario Summary

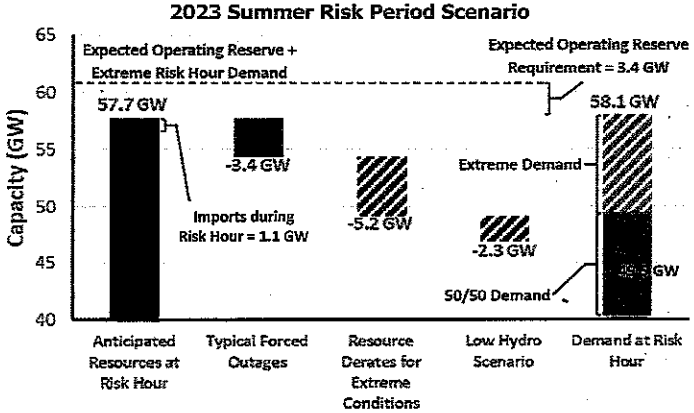
Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios studied.

On-Peak Fuel Mix



- Coal
- Natural Gas
- Solar
- Geothermal
- Pumped Storage
- Hybrid
- Battery
- Petroleum
- Biomass
- Wind
- Conventional Hydro
- Nuclear
- Other

2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy at 8:00 p.m. local time as solar PV output is diminished and demand remains high

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Estimated using market forced outage model

Extreme Derates: On natural gas units based on historic data and manufacturer data for temperature performance and outages

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

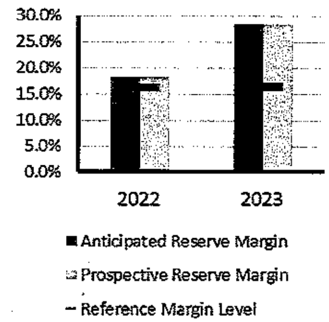
WECC-NW

WECC-NW is a summer-peaking assessment area in the WECC Regional Entity. The area includes Colorado, Idaho, Montana, Oregon, Utah, Washington, Wyoming and parts of California, Nebraska, Nevada, and South Dakota. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California in Mexico as well as all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- NW shows adequate reserve margins under expected conditions on the peak hour. However, NW shows increased risk a few hours later during the peak riskiest hour, due to the variability of energy availability later in the evenings. NW would be reliant on increased imports.
- Based on a WECC Probabilistic Assessment, the WECC-NW assessment area had negligible LOLH and EUE.
- WECC-NW would need to rely on imports to maintain adequate reserves on the peak riskiest hour (five hours later at 9:00 p.m.) under an extreme summer peak load and either extreme thermal or extreme hydro derates or any combination of two other extreme derate scenarios.

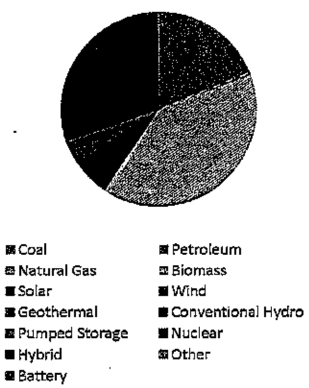
On-Peak Reserve Margin



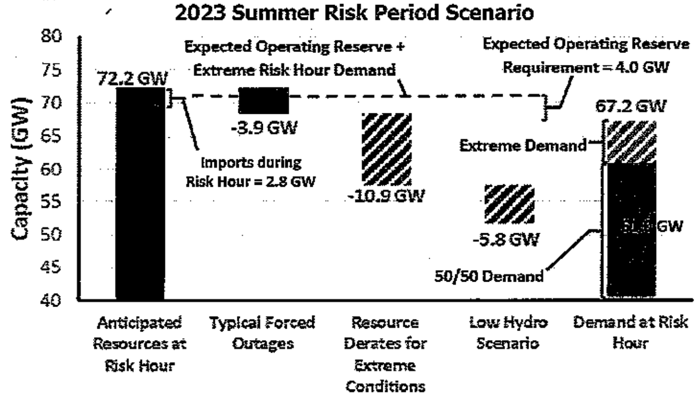
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

- **Risk Period:** Highest risk for unserved energy at 9:00 p.m. local time as solar PV output is diminished and demand remains high
- **Demand Scenarios:** Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour
- **Forced Outages:** Average seasonal outages
- **Extreme Derates:** Using (90/10) scenario
- **Low Hydro Scenario:** Reduced hydro availability resulting from drought conditions

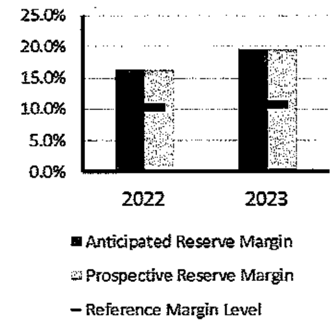
WECC-SW

WECC-SW is a summer-peaking assessment area in the WECC Regional Entity. It includes Arizona, New Mexico, and part of California and Texas. WECC is responsible for coordinating and promoting BES reliability in the Western Interconnection. WECC's 329 members include 39 BAs, representing a wide spectrum of organizations with an interest in the BES. Serving an area of nearly 1.8 million square miles and more than 82 million customers, it is geographically the largest and most diverse Regional Entity. WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia in Canada as well as the northern portion of Baja California in Mexico and all or portions of the 14 Western United States in between.

Highlights

- The Western Interconnection is experiencing heightened reliability risks heading into the summer of 2023 due to increased supply-side shortages along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events.
- WECC-SW shows adequate reserve margins to meet demand under extreme conditions.
- Based on a WECC Probabilistic Assessment, the WECC-SW assessment area had negligible LOLH and EUE.
- WECC-SW is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 5:00 p.m. under a summer peak defined as a one-in-ten probability at the 90th percentile with any combination or accumulation of derates.

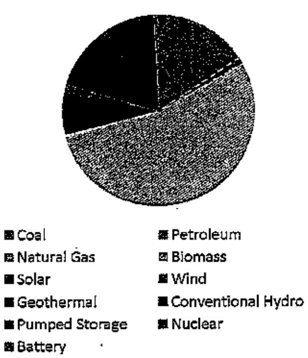
On-Peak Reserve Margin



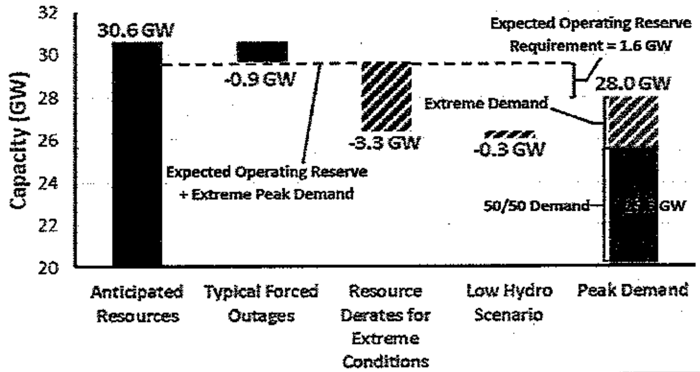
Risk Scenario Summary

Expected resources meet operating reserve requirements under normal peak-demand scenarios. Above-normal summer peak load and outage conditions could result in the need to employ operating mitigations (i.e., demand response and transfers) and EEAs. Load shedding may be needed under extreme peak demand and outage scenarios.

On-Peak Fuel Mix



2023 Summer Risk Period Scenario



Scenario Description (See Data Concepts and Assumptions)

Risk Period: Highest risk for unserved energy occurs at the hour of peak demand (5:00 p.m. local)

Demand Scenarios: Net internal demand (50/50) at risk hour and (90/10) demand forecast at risk hour

Forced Outages: Average seasonal outages

Extreme Derates: Using (90/10) scenario

Low Hydro Scenario: Reduced hydro availability resulting from drought conditions

Data Concepts and Assumptions

The table below explains data concepts and important assumptions used throughout this assessment.

General Assumptions

- Reliability of the interconnected BPS is comprised of both adequacy and operating reliability:
  - Adequacy is the ability of the electricity system to supply the aggregate electric power and energy requirements of the electricity consumers at all times while taking into account scheduled and reasonably expected unscheduled outages of system components.
  - Operating reliability is the ability of the electricity system to withstand sudden disturbances, such as electric short-circuits or unanticipated loss of system components.
- The reserve margin calculation is an important industry planning metric used to examine future resource adequacy.
- All data in this assessment is based on existing federal, state, and provincial laws and regulations.
- Differences in data collection periods for each assessment area should be considered when comparing demand and capacity data between year-to-year seasonal assessments.
- *2022 Long-Term Reliability Assessment* data has been used for most of this 2023 summer assessment period augmented by updated load and capacity data.
- A positive net transfer capability would indicate a net importing assessment area; a negative value would indicate a net exporter.

Demand Assumptions

- Electricity demand projections, or load forecasts, are provided by each assessment area.
- Load forecasts include peak hourly load[10] or total internal demand for the summer and winter of each year.[11]
- Total internal demand projections are based on normal weather (50/50 distribution[12]) and are provided on a coincident[13] basis for most assessment areas.
- Net internal demand is used in all reserve margin calculations, and it is equal to total internal demand then reduced by the amount of controllable and dispatchable demand response projected to be available during the peak hour.

Resource Assumptions

Resource planning methods vary throughout the North American BPS. NERC uses the categories below to provide a consistent approach for collecting and presenting resource adequacy. Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, their contribution to reserve margins and other on-peak resource adequacy analysis is less than their nameplate capacity.

Anticipated Resources:

- **Existing-Certain Capacity:** Included in this category are commercially operable generating unit or portions of generating units that meet at least one of the following requirements when examining the period of peak demand for the summer season: unit must have a firm capability and have a power purchase agreement with firm transmission that must be in effect for the unit; unit must be classified as a designated network resource; and/or where energy-only markets exist, unit must be a designated market resource eligible to bid into the market.
- **Tier 1 Capacity Additions:** This category includes capacity that either is under construction or has received approved planning requirements.
- **Net Firm Capacity Transfers (Imports minus Exports):** This category includes transfers with firm contracts.

[10] *Glossary of Terms* used in NERC Reliability Standards
[11] The summer season represents June–September and the winter season represents December–February.
[12] Essentially, this means that there is a 50% probability that actual demand will be higher and a 50% probability that actual demand will be lower than the value provided for a given season/year.
[13] Coincident: This is the sum of two or more peak loads that occur in the same hour. Noncoincident: This is the sum of two or more peak loads on individual systems that do not occur in the same time interval; this is meaningful only when considering loads within a limited period of time, such as a day, a week, a month, a heating or cooling season, and usually for not more than one year. SERC and FRCC calculate total internal demand on a noncoincidental basis.

Prospective Resources: Includes all anticipated resources plus the following:

Existing-Other Capacity: Included in this category are commercially operable generating units or portions of generating units that could be available to serve load for the period of peak demand for the season but do not meet the requirements of existing-certain.

Reserve Margin Descriptions

Planning Reserve Margin: This is the primary metric used to measure resource adequacy; it is defined as the difference in resources (anticipated or prospective) and net internal demand then divided by net internal demand and shown as a percentage.

Reference Margin Level: The assumptions and naming convention of this metric vary by assessment area. The Reference Margin Level can be determined using both deterministic and probabilistic (based on a 0.1/year loss of load study) approaches. In both cases, this metric is used by system planners to quantify the amount of reserve capacity in the system above the forecasted peak demand that is needed to ensure sufficient supply to meet peak loads. Establishing a Reference Margin Level is necessary to account for long-term factors of uncertainty involved in system planning, such as unexpected generator outages and extreme weather impacts that could lead to increase demand beyond what was projected in the 50/50 load forecasted. In many assessment areas, a Reference Margin Level is established by a state, provincial authority, ISO/RTO, or other regulatory body. In some cases, the Reference Margin Level is a requirement. Reference Margin Levels may be different for the summer and winter seasons. If a Reference Margin Level is not provided by an assessment area, NERC applies 15% for predominately thermal systems and 10% for predominately hydro systems.

Seasonal Risk Scenario Chart Description

Each assessment area performed an operational risk analysis that was used to produce the seasonal risk scenario charts in the Regional Assessments Dashboards. The chart presents deterministic scenarios for further analysis of different resource and demand levels: The left blue column shows anticipated resources, and the two orange columns at the right show the two demand scenarios of the normal peak net internal demand and the extreme summer peak demand—both determined by the assessment area. The middle red or green bars show adjustments that are applied cumulatively to the anticipated resources, such as the following:

- Reductions for typical generation outages (i.e., maintenance and forced outages that are not already accounted for in anticipated resources)
- Reductions that represent additional outage or performance derating by resource type for extreme, low-probability conditions (e.g., drought condition impacts on hydroelectric generation, low-wind scenario affecting wind generation, fuel supply limitations, or extreme temperature conditions that result in reduced thermal generation output)
- Additional capacity resources that represent quantified capacity from operational procedures, if any, that are made available during scarcity conditions

Not all assessment areas have the same categories of adjustments to anticipated resources. Furthermore, each assessment area determined the adjustments to capacity based on methods or assumptions that are summarized below the chart. Methods and assumptions differ by assessment area and may not be comparable.

The chart enables evaluation of resource levels against levels of expected operating reserve requirement and the forecasted demand. Furthermore, the effects from extreme events can also be examined by comparing resource levels after applying extreme-scenario derates and/or extreme summer peak demand.

Resource Adequacy

The Anticipated Reserve Margin, which is based on available resource capacity, is a metric used to evaluate resource adequacy by comparing the projected capability of anticipated resources to serve forecast peak demand.[14] Large year-to-year changes in anticipated resources or forecast peak demand (net internal demand) can greatly impact Planning Reserve Margin calculations. All assessment areas have sufficient Anticipated Reserve Margins to meet or exceed their Reference Margin Level for the 2023 summer as shown in **Figure 4**.

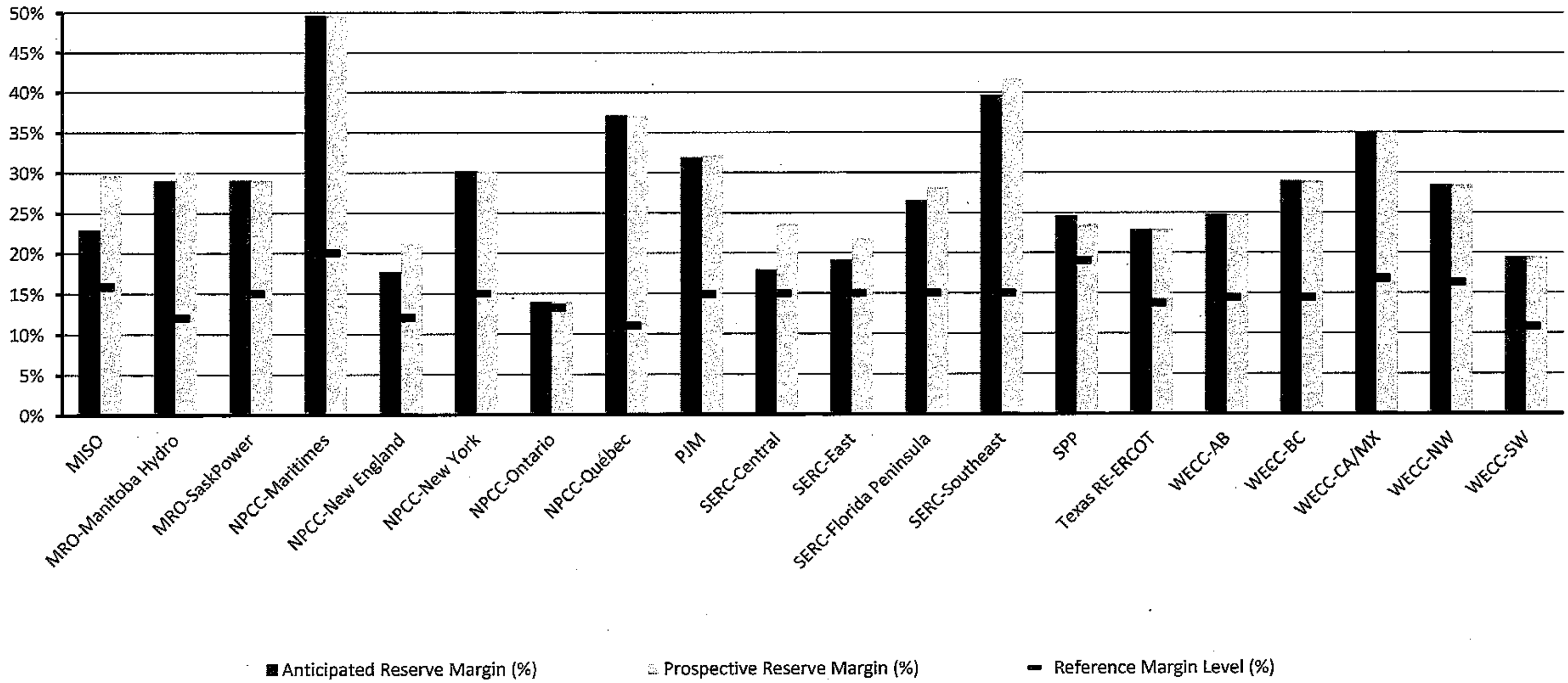
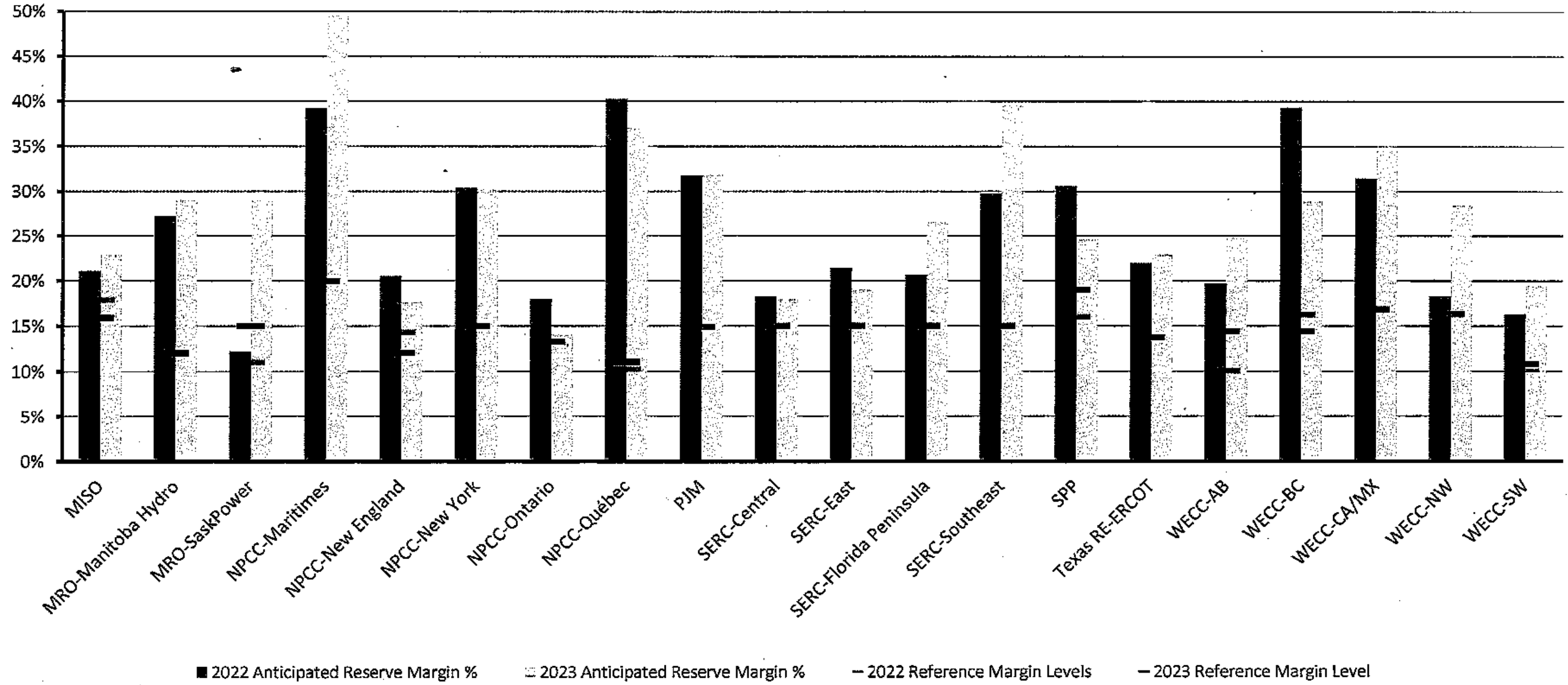


Figure 4: Summer 2023 Anticipated/Prospective Reserve Margins Compared to Reference Margin Level

[14] Generally, anticipated resources include generators and firm capacity transfers that are expected to be available to serve load during electrical peak loads for the season. Prospective resources are those that could be available but do not meet criteria to be counted as anticipated resources. Refer to the **Data Concepts and Assumptions** section for additional information on Anticipated/Prospective Reserve Margins, anticipated/prospective resources, and Reference Margin Levels.

Changes from Year-to-Year

Figure 5 provides the relative change in the forecast Anticipated Reserve Margins from the 2022 summer to the 2023 summer. A significant decline can indicate potential operational issues that emerge between reporting years. NPCC-Ontario, SPP and WECC-BC have noticeable reductions in anticipated resources with NPCC-Ontario close to falling below its Reference Margin Level for the 2023 summer. NPCC-Ontario is experiencing ongoing nuclear refurbishments and recent retirements will make it difficult to accommodate unplanned generator or transmission outages. NPCC-Ontario will rely on demand response and transfers from neighbors during a higher load scenario to avoid load interruption. The lower Anticipated Reserve Margins for NPCC-Maritimes, NPCC-Québec, SERC-C, and WECC-AB do not present reliability concerns on peak for this upcoming summer. Additional details for each assessment area are provided in the **Data Concepts and Assumptions** and **Regional Assessments Dashboards** sections.



Note: The areas that only have one bar have the same Reference Margin Level for both years.

Figure 5: Summer 2022 and Summer 2023 Anticipated Reserve Margins Year-to-Year Change

Net Internal Demand

The changes in forecasted Net Internal Demand for each assessment area are shown in **Figure 6.**[15] Assessment areas develop these forecasts based on historic load and weather information as well as other long-term projections.

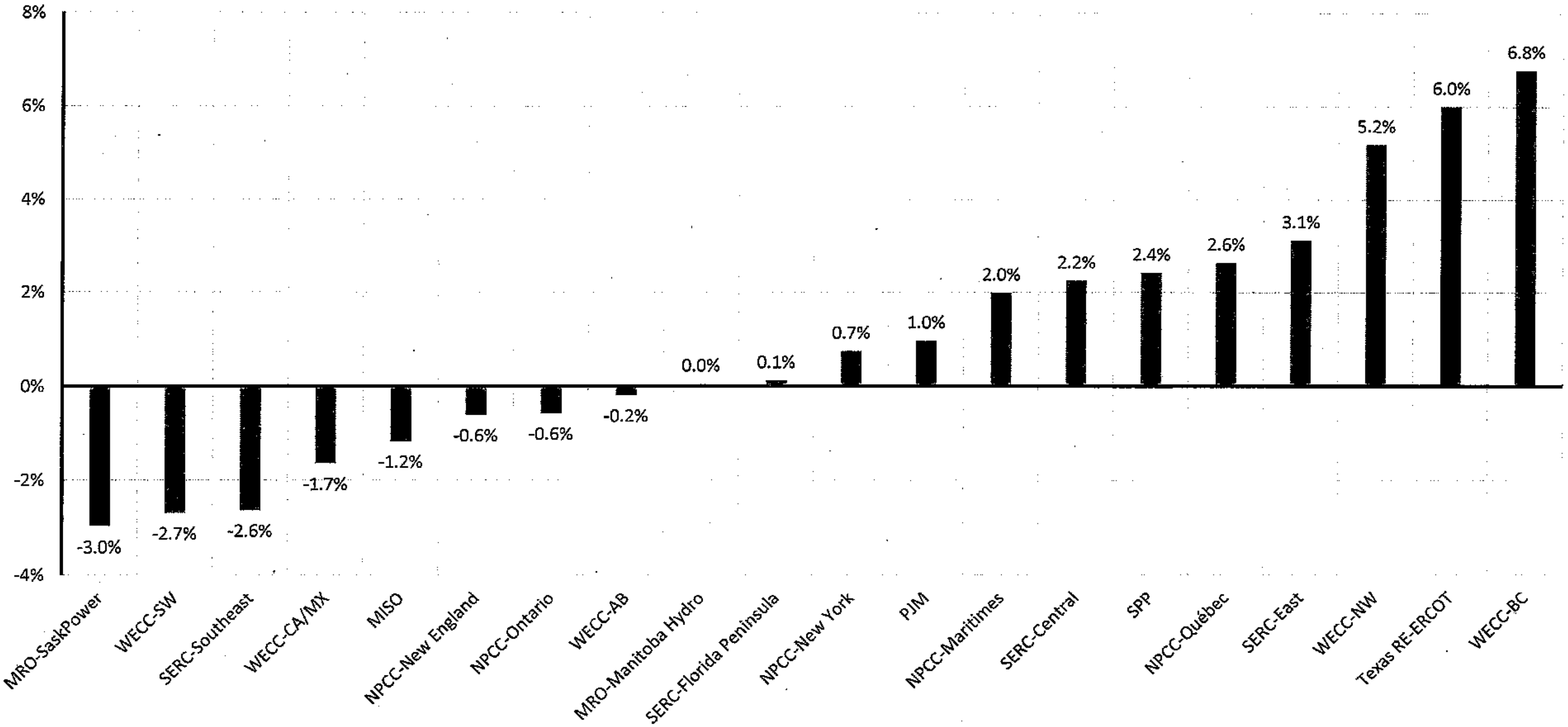


Figure 6: Change in Net Internal Demand—Summer 2022 Forecast Compared to Summer 2023 Forecast

[15] Changes in modeling and methods may also contribute to year-to-year changes in forecasted net internal demand projections.

Demand and Resource Tables

Peak demand and supply capacity data—resource adequacy data—for each assessment area are as follows in each table (in alphabetical order).

MISO			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	124,506	123,728	-0.6%
Demand Response: Available	6,287	6,903	9.8%
Net Internal Demand	118,220	116,825	-1.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	141,844	140,650	-0.8%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,353	3,018	123.1%
Anticipated Resources	143,197	143,668	0.3%
Existing-Other Capacity	669	668	-0.1%
Prospective Resources	149,756	151,579	1.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	21.1%	23.0%	1.8
Prospective Reserve Margin	26.7%	29.7%	3.1
Reference Margin Level	17.9%	15.9%	-2.0

MRO-Manitoba Hydro			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,059	3,060	0.0%
Demand Response: Available	0	0	-
Net Internal Demand	3,059	3,060	0.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	5,523	5,731	3.8%
Tier 1 Planned Capacity	186	91	-50.9%
Net Firm Capacity Transfers	-1,816	-1,872	3.1%
Anticipated Resources	3,893	3,950	1.5%
Existing-Other Capacity	44	34	-23.4%
Prospective Resources	3,937	3,984	1.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	27.3%	29.1%	1.8
Prospective Reserve Margin	28.7%	30.2%	1.5
Reference Margin Level	12.0%	12.0%	0.0

MRO-SaskPower			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,656	3,539	-3.2%
Demand Response: Available	60	50	-16.7%
Net Internal Demand	3,596	3,489	-3.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	3,743	4,213	12.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	290	290	0.0%
Anticipated Resources	4,033	4,503	11.7%
Existing-Other Capacity	0	0	-
Prospective Resources	4,033	4,503	11.7%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	12.2%	29.1%	16.9
Prospective Reserve Margin	12.2%	29.1%	16.9
Reference Margin Level	11.0%	15.0%	4.0

NPCC-Maritimes			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	3,475	3,612	3.9%
Demand Response: Available	255	328	28.6%
Net Internal Demand	3,220	3,284	2.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	4,419	4,834	9.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	64	81	26.6%
Anticipated Resources	4,483	4,915	9.6%
Existing-Other Capacity	0	0	-
Prospective Resources	4,483	4,915	9.6%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	39.2%	49.7%	10.4
Prospective Reserve Margin	39.2%	49.7%	10.4
Reference Margin Level	20.0%	20.0%	0.0

NPCC-New England			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	25,300	25,111	-0.7%
Demand Response: Available	483	447	-7.5%
Net Internal Demand	24,817	24,664	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	28,626	27,997	-2.2%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	1,292	1,030	-20.3%
Anticipated Resources	29,918	29,027	-3.0%
Existing-Other Capacity	911	872	-4.3%
Prospective Resources	30,829	29,899	-3.0%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	20.6%	17.7%	-2.9
Prospective Reserve Margin	24.2%	21.2%	-3.0
Reference Margin Level	14.3%	12.0%	-2.3

NPCC-Ontario			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,546	22,439	-0.5%
Demand Response: Available	666	687	3.1%
Net Internal Demand	21,880	21,752	-0.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	25,648	24,575	-4.2%
Tier 1 Planned Capacity	24	9	-61.5%
Net Firm Capacity Transfers	150	223	48.5%
Anticipated Resources	25,822	24,807	-3.9%
Existing-Other Capacity	0	0	-
Prospective Resources	25,822	24,807	-3.9%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	18.0%	14.0%	-4.0
Prospective Reserve Margin	18.0%	14.0%	-4.0
Reference Margin Level	13.3%	13.2%	0.0

NPCC-New York			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	31,765	32,049	0.9%
Demand Response: Available	1,170	1,226	4.8%
Net Internal Demand	30,595	30,823	0.7%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	37,431	37,216	-0.6%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	2,465	2,932	18.9%
Anticipated Resources	39,896	40,148	0.6%
Existing-Other Capacity	0	0	-
Prospective Resources	39,896	40,148	0.6%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	30.4%	30.3%	-0.1
Prospective Reserve Margin	30.4%	30.3%	-0.1
Reference Margin Level	15.0%	15.0%	0.0

NPCC-Québec			
Demand, Resource, and Reserve Margins	**2022 SRA**	**2023 SRA**	**2022 vs. 2023 SRA**
Demand Projections	**MW**	**MW**	**Net Change (%)**
Total Internal Demand (50/50)	22,271	22,859	2.6%
Demand Response: Available	0	0	-
Net Internal Demand	22,271	22,859	2.6%
Resource Projections	**MW**	**MW**	**Net Change (%)**
Existing-Certain Capacity	33,542	33,690	0.4%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-2,304	-2,353	2.1%
Anticipated Resources	31,238	31,337	0.3%
Existing-Other Capacity	0	0	-
Prospective Resources	31,238	31,337	0.3%
Reserve Margins	**Percent (%)**	**Percent (%)**	**Annual Difference**
Anticipated Reserve Margin	40.3%	37.1%	-3.2
Prospective Reserve Margin	40.3%	37.1%	-3.2
Reference Margin Level	10.3%	11.0%	0.7

PJM			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	148,938	149,059	0.1%
Demand Response: Available	8,527	7,288	-14.5%
Net Internal Demand	140,411	141,771	1.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	184,837	186,540	0.9%
Tier 1 Planned Capacity	10	0	-100.0%
Net Firm Capacity Transfers	124	463	273.4%
Anticipated Resources	184,971	187,003	1.1%
Existing-Other Capacity	0	0	-
Prospective Resources	185,095	187,466	1.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	31.7%	31.9%	0.2
Prospective Reserve Margin	31.8%	32.2%	0.4
Reference Margin Level	14.9%	14.9%	0.0

SERC-East			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	42,883	43,889	2.3%
Demand Response: Available	1,298	1,008	-22.3%
Net Internal Demand	41,585	42,881	3.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	49,380	50,452	2.2%
Tier 1 Planned Capacity	486	0	-100.0%
Net Firm Capacity Transfers	612	624	2.0%
Anticipated Resources	50,478	51,076	1.2%
Existing-Other Capacity	1,097	1,182	7.8%
Prospective Resources	51,575	52,258	1.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	21.4%	19.1%	-2.3
Prospective Reserve Margin	24.0%	21.9%	-2.2
Reference Margin Level	15.0%	15.0%	0.0

SERC-Central			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	41,267	42,223	2.3%
Demand Response: Available	1,841	1,910	3.7%
Net Internal Demand	39,426	40,313	2.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	47,424	46,964	-1.0%
Tier 1 Planned Capacity	0	93	-
Net Firm Capacity Transfers	-795	1,068	-
Anticipated Resources	46,629	47,556	2.0%
Existing-Other Capacity	4,808	2,313	-51.9%
Prospective Resources	51,437	49,868	-3.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	18.3%	18.0%	-0.3
Prospective Reserve Margin	30.5%	23.7%	-6.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Florida Peninsula			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	52,172	52,195	0.0%
Demand Response: Available	2,932	2,898	-1.2%
Net Internal Demand	49,240	49,297	0.1%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	56,571	60,074	6.2%
Tier 1 Planned Capacity	2,540	1,742	-31.4%
Net Firm Capacity Transfers	300	589	96.3%
Anticipated Resources	59,411	62,405	5.0%
Existing-Other Capacity	847	776	-8.4%
Prospective Resources	60,258	63,181	4.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	20.7%	26.6%	5.9
Prospective Reserve Margin	22.4%	28.2%	5.8
Reference Margin Level	15.0%	15.0%	0.0

SERC-Southeast			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	47,258	46,127	-2.4%
Demand Response: Available	1,946	2,010	3.3%
Net Internal Demand	45,312	44,117	-2.6%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	59,828	59,559	-0.4%
Tier 1 Planned Capacity	1,514	2,865	89.3%
Net Firm Capacity Transfers	-2,524	-815	-67.7%
Anticipated Resources	58,818	61,609	4.7%
Existing-Other Capacity	859	908	5.7%
Prospective Resources	59,677	62,517	4.8%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	29.8%	39.6%	9.8
Prospective Reserve Margin	31.7%	41.7%	10.0
Reference Margin Level	15.0%	15.0%	0.0

SPP			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	52,040	53,468	2.7%
Demand Response: Available	658	842	27.9%
Net Internal Demand	51,382	52,626	2.4%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	67,245	65,821	-2.1%
Tier 1 Planned Capacity	0	0	-
Net Firm Capacity Transfers	-144	-238	65.0%
Anticipated Resources	67,101	65,583	-2.3%
Existing-Other Capacity	0	0	-
Prospective Resources	66,554	65,036	-2.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	30.6%	24.6%	-6.0
Prospective Reserve Margin	29.5%	23.6%	-5.9
Reference Margin Level	16.0%	19.0%	3.0

Texas RE-ERCOT			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	77,317	82,307	6.5%
Demand Response: Available	2,856	3,380	18.3%
Net Internal Demand	74,461	78,927	6.0%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	89,603	94,580	5.6%
Tier 1 Planned Capacity	1,199	2,445	103.9%
Net Firm Capacity Transfers	20	20	0.0%
Anticipated Resources	90,822	97,045	6.9%
Existing-Other Capacity	0	0	-
Prospective Resources	90,850	97,073	6.9%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	22.0%	23.0%	1.0
Prospective Reserve Margin	22.0%	23.0%	1.0
Reference Margin Level	13.75%	13.75%	0.0

WECC-AB			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	11,228	11,206	-0.2%
Demand Response: Available	0	0	-
Net Internal Demand	11,228	11,206	-0.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	11,926	13,759	15.4%
Tier 1 Planned Capacity	1,082	227	-79.0%
Net Firm Capacity Transfers	437	0	-100.0%
Anticipated Resources	13,445	13,986	4.0%
Existing-Other Capacity	0	0	-
Prospective Resources	13,445	13,986	4.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	19.7%	24.8%	5.1
Prospective Reserve Margin	19.7%	24.8%	5.1
Reference Margin Level	10.1%	9.9%	-0.2

WECC-BC			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	8,088	8,636	6.8%
Demand Response: Available	0	0	-
Net Internal Demand	8,088	8,636	6.8%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	11,266	11,135	-1.2%
Tier 1 Planned Capacity	3	0	-100.0%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	11,269	11,135	-1.2%
Existing-Other Capacity	0	0	-
Prospective Resources	11,269	11,135	-1.2%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	39.3%	28.9%	-10.4
Prospective Reserve Margin	39.3%	28.9%	-10.4
Reference Margin Level	16.3%	14.4%	-1.9

WECC-CA/MX			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	57,269	56,356	-1.6%
Demand Response: Available	844	862	2.2%
Net Internal Demand	56,425	55,494	-1.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	70,791	69,408	-2.0%
Tier 1 Planned Capacity	3,381	5,522	63.3%
Net Firm Capacity Transfers	0	0	-
Anticipated Resources	74,172	74,930	1.0%
Existing-Other Capacity	0	0	-
Prospective Resources	74,172	74,930	1.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	31.5%	35.0%	3.6
Prospective Reserve Margin	31.5%	35.0%	3.6
Reference Margin Level	16.9%	16.8%	-0.1

WECC-SW			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	26,720	25,992	-2.7%
Demand Response: Available	399	380	-4.7%
Net Internal Demand	26,321	25,612	-2.7%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	28,249	26,206	-7.2%
Tier 1 Planned Capacity	1,369	1,655	20.9%
Net Firm Capacity Transfers	1,002	2,747	174.2%
Anticipated Resources	30,620	30,608	0.0%
Existing-Other Capacity	0	0	-
Prospective Resources	30,620	30,608	0.0%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	16.3%	19.5%	3.2
Prospective Reserve Margin	16.3%	19.5%	3.2
Reference Margin Level	10.2%	10.8%	0.6

WECC-NW			
Demand, Resource, and Reserve Margins	2022 SRA	2023 SRA	2022 vs. 2023 SRA
Demand Projections	MW	MW	Net Change (%)
Total Internal Demand (50/50)	63,214	66,366	5.0%
Demand Response: Available	1,104	1,038	-6.0%
Net Internal Demand	62,110	65,328	5.2%
Resource Projections	MW	MW	Net Change (%)
Existing-Certain Capacity	70,154	76,587	9.2%
Tier 1 Planned Capacity	798	2,350	194.5%
Net Firm Capacity Transfers	2,517	5,004	98.8%
Anticipated Resources	73,469	83,941	14.3%
Existing-Other Capacity	0	0	-
Prospective Resources	73,469	83,941	14.3%
Reserve Margins	Percent (%)	Percent (%)	Annual Difference
Anticipated Reserve Margin	18.3%	28.5%	10.2
Prospective Reserve Margin	18.3%	28.5%	10.2
Reference Margin Level	16.1%	16.3%	0.2

Variable Energy Resource Contributions

Because the electrical output of variable energy resources (e.g., wind, solar PV) depends on weather conditions, on-peak capacity contributions are less than nameplate capacity. The following table shows the capacity contribution of existing wind and solar PV resources at the peak demand hour for each assessment area. Resource contributions are also aggregated by Interconnection and across the entire BPS. For NERC's analysis of risk periods after peak demand (i.e., U.S. assessment areas in WECC), lower contributions of solar PV resources are used because output is diminished during evening periods.

BPS Variable Energy Resources by Assessment Area									
	Wind			Solar			Hydro		
Assessment Area / Interconnection	Nameplate Wind	Expected Wind	Expected Share of Nameplate (%)	Nameplate Solar PV	Expected Solar PV	Expected Share of Nameplate (%)	Nameplate Hydro	Expected Hydro	Expected Share of Nameplate (%)
MISO	30,373	5,488	18%	7,499	3,750	50%	4,884	4,688	96%
MRO-Manitoba Hydro	259	47	18%	-	-	0%	6,220	5,548	89%
MRO-SaskPower	615	203	33%	30	-	0%	851	797	94%
NPCC-Maritimes	1,212	255	21%	4	-	0%	1,315	1,183	90%
NPCC-New England	1,448	186	13%	2,914	1,163	40%	3,565	2,472	69%
NPCC-New York	2,879	331	12%	179	84	47%	6,731	5,067	75%
NPCC-Ontario	4,943	771	16%	478	126	26%	8,985	5,185	58%
NPCC-Québec	3,880	-	0%	10	-	0%	40,307	32,974	82%
PJM	10,923	1,688	15%	5,169	2,984	58%	3,027	3,027	100%
SERC-Central	1,206	564	47%	885	511	58%	4,967	3,315	67%
SERC-East	-	-	0%	1,475	1,473	99%	3,064	3,013	98%
SERC-Florida Peninsula	-	-	0%	7,724	4,534	59%	-	-	0%
SERC-Southeast	-	-	0%	5,305	4,647	88%	3,242	3,288	101%
SPP	32,028	4,500	14%	440	378	86%	5,465	4,996	91%
Texas RE-ERCOT	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC-AB	3,619	309	9%	1,165	763	65%	894	416	47%
WECC-BC	747	137	18%	2	1	50%	16,519	10,124	61%
WECC-CA/MX	9,362	1,111	12%	21,975	14,489	66%	13,957	4,606	33%
WECC-SW	2,994	593	20%	3,493	1,411	40%	1,202	844	70%
WECC-NW	20,296	3,968	20%	9,270	5,062	55%	41,860	22,752	54%
EASTERN INTERCONNECTION	85,886	14,032	16%	32,102	19,649	61%	52,316	42,578	81%
QUÉBEC INTERCONNECTION	3,880	-	0%	10	-	0%	40,307	32,974	82%
TEXAS INTERCONNECTION	30,938	10,293	33%	15,958	12,509	78%	563	477	85%
WECC INTERCONNECTION	37,018	6,118	17%	35,905	21,726	61%	74,432	38,742	52%
INTERCONNECTION TOTAL:	157,722	30,443	19%	83,975	53,885	64%	167,618	114,771	68%

Probabilistic Assessment

Regional Entities and assessment areas provided a resource adequacy risk assessment that was probability-based for the summer season. Results are included in the Highlights section of each assessment area's dashboard and summarized in the table below. The risk assessments account for the hour(s) of greatest risk of resource shortfall. For most areas, the hour(s) of risk coincide with the time of forecasted peak demand; however, some areas incur the greatest risk at other times based on the varying demand and resource profiles. Various risk metrics are provided and include LOLE, LOLH, EUE, and the probabilities of EEA occurrence.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
MISO	Annual probabilistic LOLE study	MISO's RML decreased from 17.9% in 2022 to 15.9% for Summer 2023. The change results from implementing seasonal forced outages and probabilistic distributions of non-firm imports. Operating mitigations are needed in extreme peak summer conditions.
MRO-Manitoba	Verification of NERC 2022 Probabilistic Assessment (2022 ProbA)	The 2022 ProbA results indicate 29 MWh per year of EUE for 2024. Given comparable supply and demand balance, the 2024 EUE is a reasonable estimate for all of 2023. EUE for summer is less than the annual EUE.
MRO-SaskPower	Probability-based capacity adequacy assessment	Results indicate that the expected number of hours with operating reserve deficiency for the 2023 summer season (June to September) is 0.21 hours. September is the month with highest risk.
NPCC	NPCC conducted an all-hour Probabilistic Assessment that consisted of a base case and several more severe scenarios examining low resources, reduced imports, and higher loads. The highest peak load scenario has a 7% probability of occurring.	The assessment forecasts that the NPCC Regional Entity will have an adequate supply of electricity this summer. Necessary strategies and procedures are in place to deal with operational challenges and emergencies as they may develop. Results of the probabilistic analysis by assessment area are below.
NPCC-Maritimes		NPCC's assessment results indicate that Maritimes is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Cumulative LOLE (<0.03 days/summer), LOLH (<0.11 hours/summer), or EUE (<5 MWh/summer) were estimated over the May–September summer for all modeled scenarios.
NPCC-New England		NPCC's assessment results indicate that ISO-NE may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.12 days/period) with associated LOLHs (0.4 hours/period) and EUE (175 MWh/period) with the highest risk occurring in June. This scenario is based exclusively on the two highest load levels with a 7% chance of occurring and a low resource case consisting of extended summer maintenance across NPCC and reduced imports from PJM.
NPCC-New York		NPCC's assessment results indicate that NYISO may rely on limited use of its operating procedures to mitigate resource and energy shortages during the summer. The reduced resource case with the highest peak load scenario resulted in a small estimated cumulative LOLE risk (0.5 days/summer) with associated LOLH (1.1 hours/summer) and EUE (525 MWh/summer). The highest risk is in June and August.
NPCC-Ontario		NPCC's assessment results indicate that Ontario is likely to use a combination of imports and operating procedures to mitigate resource shortages this summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases. These results indicate that Ontario will be able to obtain necessary supplies from neighbors over a range of conditions.

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
NPCC-Québec		Québec is expected to need only limited use of its operating procedures designed to mitigate resource and energy shortages during the summer. Negligible cumulative LOLE, LOLH, and EUE risks were estimated over the summer period for all modeled scenarios, including the severe low-likelihood cases.
PJM	Based on 2022 PJM Reserve Requirement Study (RRS)	PJM is expecting a low risk of resources falling below required operating reserves. PJM forecasts a 29% installed reserve margin, well above the target of 14.9%. Due to the low penetration of variable energy resources in PJM relative to PJM's peak load, the hour with most loss of load risk remains the hour with highest forecasted demand.
SERC	Verification of NERC 2022 ProbA Results	The 2022 Base Case results indicated adequate resources for the SERC Region as a whole with an observed LOLE of 0.03 days/year for the year 2024. Trends from 2022 to 2023 indicate little change in study results, so SERC does not anticipate resource adequacy risk for the upcoming summer season.
SERC-Central		Probabilistic analysis indicates no risk for resource shortfall.
SERC-East		Probabilistic analysis shows low risk for July and August with EUE of 2.38 MWh and LOLH 0.005 hours.
SERC-Florida Peninsula		SERC Probabilistic analysis indicates no risk of resource shortfall.
SERC-Southeast		Probabilistic analysis indicates almost no risk of resource shortfall.
SPP	Statistical analysis of the Summer 2022 real time data; Operational process and procedures	Potential risk of using operating reserves and EEA1 or EEA2 is 1 day per summer. Risk of EEA3 is 0.2 days per summer. Risks is associated with low wind generation output levels or unanticipated generation outages in combination with high load periods.
Texas RE-ERCOT	ERCOT's Summer 2023 Probabilistic Assessment	There is a 4% probability that ERCOT will declare an EEA1 during the expected daily peak load hour; Increasing up to 19% probability at the highest risk hour and ending at 8:00 p.m.
WECC	The 2022 Western Assessment of Resource Adequacy provides the most recent probability-based resource adequacy risk assessment for Summer 2023 across WECC's areas.	The Western Interconnection is experiencing heightened reliability risks heading into Summer 2023 due to increased supply-side shortages and fuel constraints along with the ongoing drought impacts in some areas, continued wildfire threats, and expanding heat wave events. The installation of new resources for the summer and the availability of the imports, especially during wide-area heat events, affects resource adequacy for the U.S. assessment areas. The reliability and resource adequacy of the Western Interconnection depends on the ability to move power throughout the footprint.
WECC-AB		Alberta is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-BC		BC is expected to have sufficient resource availability to meet demand and cover reserves on the peak hour at 4:00 p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates.
WECC-CA/MX		WECC-CA/MX is projected to have negligible-to-low amounts of LOLH (<0.5 hours) this summer with variation attributable to the amount of Tier 1 resources that connect before the later months. Resources are sufficient to meet demand and cover reserves on the peak hour at 3:00

Probability-Based Risk Assessment		
Assessment Area	**Type of Assessment**	**Results and Insight From Assessment**
		p.m. under a summer peak defined at the 90th percentile with any combination or accumulation of derates. However, there is increased risk of insufficient reserves at later hours (up to 8:00 p.m.) due to the variability of energy resource output. Imports to the area are required to cover these risk periods; however, regional resource availability and transmission constraints can affect external assistance during wide area heat events.
WECC-NW		WECC-NW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<400 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted. WECC-NW would rely on imports to maintain adequate reserves on the during the risk hours from 4:00–9:00 p.m. under extreme summer peak load and low-resource conditions (e.g., extreme thermal or extreme hydro derates or combinations of other low energy output scenarios.)
WECC-SW		WECC-SW assessment area is projected to have negligible LOLH and EUE this summer with planned resource additions and normal transfer availability. However, some LOLH (<0.1) and EUE (<150 MWh) is anticipated during above-normal demand periods if new resource are delayed or external transfers are disrupted.

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America's Cement Manufacturers™

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June 6, 2023

The Honorable Bill Johnson
Subcommittee on Environment,
Manufacturing, & Critical Materials
Energy & Commerce Committee
Washington, DC 20150

The Honorable Paul Tonko
Subcommittee on Environment,
Manufacturing, & Critical Materials
Energy & Commerce Committee
Washington, DC 20150

Chairman Johnson and Ranking Member Tonko:

I am writing to you on behalf of the Portland Cement Association[1] (PCA) in regard to the *Clean Power Plan 2.0: EPA's Latest Attack On America's Electric Reliability Hearing.* This hearing is necessary to evaluate the progress and the challenges of shifting to fuels with fewer greenhouse gas (GHG) emissions and the technologies necessary to capture, utilize, transport, and sequester carbon dioxide. Congress should take a diverse approach to reducing GHGs across the economy.

The cement and concrete industry continues to decrease the carbon intensity of its operations and products, is fully committed to decarbonization, and has pledged to become carbon neutral across the concrete value chain by 2050. On October 12, 2021, PCA released its "Roadmap to Carbon Neutrality," providing a detailed outline of technical, market, and policy levers central to achieving the industry's 2050 carbon neutrality goal.[2]

On May 23, 2023, the Environmental Protection Agency (EPA) released its proposed rule for a GHG standard at fossil-fueled power plants. As the cement industry utilizes fossil fuels to manufacture cement, the key ingredient in concrete, the industry shares some of the challenges with fuel shifting with the electric utility industry. These challenges make the EPA's proposed timeline for meeting GHG reductions by 2030 difficult.

By way of brief background, cement manufacturers face a unique chemical fact of life. The chemical process required to convert limestone and other raw materials into clinker, the primary ingredient in cement, generates carbon dioxide (CO2) as an unavoidable byproduct during pyro-processing. Currently, roughly 60 percent of all emissions from the cement sector come from these manufacturing process emissions, separate and distinct from energy-related emissions. While the industry expects to make great strides in reducing carbon emissions through measures like using carbon-free fuel/heating technologies and low-carbon/carbon-free raw materials, the full elimination of CO2 generated from raw materials during pyro-processing is not possible.

[1] PCA conducts market development, engineering, research, education, technical assistance, and public affairs programs on behalf of its member companies. Our mission focuses on improving and expanding the quality and uses of cement and concrete, raising the quality of construction, and contributing to a better environment.
[2] https://www.cement.org/docs/default-source/roadmap1/pca-roadmap-to-carbon-neutrality_final.pdf

Given this chemical fact of life, adopting carbon capture, utilization, and storage (CCUS) technologies is key to achieving deeper decarbonization in the cement industry.

The cement and concrete industry opposes any command-and-control emissions and technological mandates from EPA that will not be effective in furthering industrial GHG emissions reductions. The proposal from EPA likely violates the U.S. Supreme Court's ruling in *West Virginia v. EPA*, finding that under neither the Clean Air Act nor the Inflation Reduction Act did Congress delegate authority to the EPA to regulate the power industry by requiring technical and economically infeasible technologies to be installed and emissions limits to be met. As a result, this issue remains a major question and violates the Clean Air Act under the U.S. Supreme Court's ruling in *West Virginia v. EPA*.

EPA's proposal would set an alarming precedent to regulate other high industrial emitters of GHGs. Similar to power plants the cement industry is facing significant obstacles to implementing CCUS at its plants. Currently, there are no commercial-scale CCUS installations at any cement plant within the U.S. CCUS cannot be widely implemented at cement plants until there is a clear path to siting and permitting these technologies. In addition, significant infrastructure investment is required for the capture, compression, storage, and transportation of CO2. Part of the infrastructure needed would be to supply water and energy for the carbon-capture units and associated auxiliary equipment, as well as the energy required for the ultimate delivery of the captured CO2 to its final end-use. However, with substantial research and the implementation of appropriate federal and state policies, CCUS technologies could become scalable within the next ten years, provided a technology can be proven or demonstrated at scale. Similar investments to scale up the use of hydrogen as fuel, including the infrastructure to transport hydrogen from where it is produced to plants, will be needed for hydrogen to become a viable alternative fuel for industry.

While many promising technologies are under development domestically and overseas, significantly more research and federal funding is needed for CCUS technologies to reach the commercial development stage for the industrial sector, including cement. The cement industry is conducting research on carbon capture technologies, including a variety of solvent, sorbent, and membrane technologies, carbonation, mineralization, calcium (or carbonate) looping, oxyfuel combustion and calcination, cryogenic capture, and algae capture as carbon reduction and removal technologies to hasten the industry's decarbonization efforts. The cement industry is pursuing various potential technologies because each cement plant and cement kiln is different.

Their differences include numerous variables, including plant design, emission control requirements, space constraints, water availability, energy availability, and process parameters, each of which will influence the viability of specific carbon removal and reduction technologies. No single off-the-shelf CCUS commercial design or technology will work for every cement plant, and many plants will likely require a combination of carbon capture technologies. It is essential that federal research and funding continue to be directed at multiple technologies so CCUS can feasibly be implemented for the cement industry promptly.

In addition to scaling up CCUS technologies and bringing the costs down to a level where the technology can be implemented at cement plants, the associated pipeline and energy infrastructure must be in place so CO_2 can be captured, transported, and ultimately utilized or sequestered. Without the necessary pipeline infrastructure connected to our cement plants, there is no economically feasible method to transport the captured CO_2. Likewise, the energy needed to operate a CCUS system, including energy for scrubbers, separation units, compressors, and chillers, is almost equivalent to what is required to operate a cement plant, therefore national power grids will need to be able to handle significant increases in energy usage by CCUS systems. Further, the tight domestic market for transformers and other related components for upgrading the electrical systems necessary for CCUS delays the dates for installation further into the future.

Given the challenges in decarbonizing the entire cement and concrete value chain, the cement industry will be unable to reach its carbon neutrality goal by 2050 alone. We can only achieve this goal with significant policy support from the federal government to assist with eliminating regulatory hurdles once carbon technologies are commercialized. Needed policy support includes measures to modernize the permitting programs that cover the installation of carbon capture and energy efficiency technologies, carbon transmission infrastructure, and electricity generation. Federal permitting remains an obstacle to the planning, construction, and installation of carbon capture technologies and the infrastructure needed to sequester or utilize the captured carbon.

First, there are regulatory obstacles to installing new energy-intensive carbon capture equipment at cement plants and other facilities. The New Source Review (NSR) Program, established under the Clean Air Act Amendments of 1977, presents regulatory barriers for cement facilities to make GHG reduction and energy efficiency improvements. Under the NSR Program, installing CCUS, investing in significant energy efficiency projects, or other major capital investments to reduce GHG emissions at cement facilities result in extended and costly permitting processes and potentially unrealistic emissions and monitoring requirements. The federal government will need to enact policy reforms to reduce these barriers under the NSR Program to ensure that cement plants can install major GHG reduction and energy efficiency technologies, including CCUS technologies, without unnecessary impediments.

Further, cement manufacturers face the challenge of determining where captured carbon can be sequestered or how it will be utilized. Beyond the high cost of implementing carbon technologies at scale, necessary pipeline and energy grid infrastructure must be implemented to ensure that CCUS technologies can be employed. Implementing CCUS will require a national network of CO_2 pipelines and electricity grids that can handle the loads required to operate CCUS units and, or hydrogen fuel and infrastructure to transport the hydrogen from a manufacturer to a cement plant must be in place. All these activities are regulated by numerous federal environmental laws with inconsistent guidance, permitting processes, and agency interpretations.

Lastly, as a result of the Supreme Court's ruling in West Virginia v. EPA and pending court cases, the authority of the EPA to regulate GHG emissions from power plants is vague. It would have been preferential for the EPA to wait for clarity before creating confusing requirements for industry and consumers.

We encourage the Committee to probe the intent of the agency to further regulate for GHGs in the industrial sector. We also urge the Committee to use this hearing to evaluate future federal permitting reform and investments toward the full deployment of carbon capture technologies across the economy. Such action is necessary to enable our industry to reach its goal of carbon neutrality across the concrete supply chain by 2050. We look forward to working with the Committee on legislation and agency oversight as it considers its next steps. If you have any further questions, please contact me at soneill@cement.org or 202.719.1974.

Sincerely,

S O'Neill

Sean O'Neill
Senior Vice President, Government Affairs
Portland Cement Association

TEXAS GENERAL LAND OFFICE
COMMISSIONER DAWN BUCKINGHAM, M.D.

May 22, 2023

US Environmental Protection Agency (MC 1701A)
1200 Pennsylvania Ave NW
Washington, DC 20460

RE: EPA-HQ-OAR-2023-0072

Dear Administrator Michael S. Regan:

As Commissioner of the Texas General Land Office (GLO) and steward of over 13 million acres of State lands on behalf of the people of Texas, I am appalled and extremely concerned at the draft rule proposed on May 8, 2023, by the U.S. Environmental Protection Agency (EPA) regarding carbon pollution standards for coal and natural gas-fired power plants. Simply put, the implementation of EPA-HQ-OAR-2023-0072 would be an all-out attack on the energy industry, the robust Texas economy, everyday taxpayers, and public education funding in the State of Texas.

EPA-HQ-OAR-2023-0072 mandates most coal and natural gas-fired power plants capture 90 percent of emissions by 2035 and convert to hydrogen by 2038. EPA-HQ-OAR-2023-0072 is nothing more than a blatant attack on the domestic oil and gas industry. Rather than encourage the continued use of clean and abundant natural gas for energy generation, EPA-HQ-OAR-2023-0072 seeks to burden our natural gas-fired plants with untenable restrictions to compel their closure or conversion to a fuel source like green hydrogen. Further, unless subject to additional EPA oversight, EPA-HQ-OAR-2023-0072 would not consider carbon captured from power plants under this scheme that is used for tertiary oil and gas recovery, a safe and effective use of carbon that has been utilized since the 1970's. At the GLO, we are no strangers to the challenges posed to the budding carbon capture and sequestration industry. For one, capturing carbon from natural gas plants – as opposed to coal-fired plants – is exceedingly difficult since carbon is not nearly as concentrated. If it proves to be either impossible or economically unviable to utilize this as-yet-unproven capture technology, plants will be faced with no option but to shut down.

The General Land Office (GLO) is the oldest state agency in Texas, established in 1836. The agency serves the schoolchildren, veterans and environment of Texas by maximizing State revenue through innovative administration, and exercising prudent stewardship of State lands, minerals, and natural resources. The GLO is responsible for managing over 13 million acres of State lands and mineral interests dedicated to the Permanent School Fund (PSF). The School Fund is a perpetual endowment created by the Texas Legislature in 1854 to support public schools. See TEX. CONST., art. VII, § 2. The GLO has a fiduciary duty to maximize revenues from State lands and minerals for the benefit of the School Fund. The agency generates revenue for the School Fund through oil and natural gas production, sales, leases, and other transactions involving the assets under management. The GLO has deposited over $30 billion into the School Fund since inception, including over $2.1 billion in oil and natural gas revenues during the last fiscal year.

As Land Commissioner, I also serve as the Chairwoman of the Board for Lease of University Lands, which oversees lands owned by the Permanent University Fund (PUF). The PUF owns approximately 2.1 million acres in West Texas. Similar to the PSF, the PUF is a constitutionally created fund that generates substantial revenue for the University of Texas and Texas A&M University Systems.

Due to the likelihood that EPA-HQ-OAR-2023-0072 will result in closure or curtailment of natural gas-fired power plants, and thus diminish natural gas revenues received by the School Fund and the PUF, EPA-HQ-OAR-2023-0072 will have a lasting negative impact on funding for public education in Texas. EPA-HQ-OAR-2023-0072 is undoubtedly intended to buttress the Federal Government's push to end domestic oil and natural gas production in favor of "green" renewable sources. However, as EPA-HQ-OAR-2023-0072 itself states, "Renewable energy... is both variable and intermittent." So, in addition to decreasing revenue directed to the school children and college students of Texas, EPA-HQ-OAR-2023-0072 will present an undue burden on the State's critical energy supply and Texas industry at a time when U.S. power consumption requirements are expected to increase by 12 to 22 percent between now and 2030.

Please be advised that the General Land Office will seek relief in the appropriate court to stop the EPA from proceeding with implementation of the Rule. The General Land Office respectfully requests that the EPA respond to these comments in writing. Thank you for your careful consideration.

Respectfully,

D. Buckingham

DAWN BUCKINGHAM, M.D.
Commissioner, Texas General Land Office

COMMONWEALTH of VIRGINIA

Office of the Governor

Glenn Youngkin
Governor

June 5, 2023

The Honorable Michael S. Regan
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20450

Dear Administrator Regan:

I write today in response to the EPA's unacceptable attempt to revive the failed policies of the Obama Administration's "Clean Power Plan," that was rejected by the Supreme Court in *West Virginia v. EPA*. The new standards, if imposed, would be catastrophic to our nation's power infrastructure and will deepen America's dependence on supply chains already dominated by China, furthering the Biden Administration's relentless efforts to concede fully one of America's greatest advantages, energy independence.

In Virginia, as our economy grows and power needs accelerate, we are leading with an All-American, All-of-the-Above energy plan that will deliver reliable, affordable, and increasingly clean power. Our approach embraces innovative technologies, including small modular reactors, carbon capture, hydrogen and advanced battery storage, and utilizes all fuel sources, both traditional and renewables, to bring more baseload generation and peaking capacity online while further reducing emissions from existing capacity. There's no need to predetermine power plant retirements on arbitrary timelines.

The proposed regulation requires most natural gas and coal plants, which produce over 60 percent of our electricity, to reduce emissions by 90 percent by 2035 or be forced to shut down. Already today, the announced retirements of combustion-baseload generators over the next decade far outpace planned renewable investments, leaving a gaping hole between power supply and demand.

As a state within the PJM Interconnection regional transmission organization, I was particularly alarmed by the February 2023 report that reveals 40 gigawatts of thermal generating capacity is scheduled to retire by 2030 while only 31 gigawatts of new capacity are expected to come online. Given the operating characteristics of these renewable resources, we need multiple gigawatts to replace traditional thermal sources. Instead of heeding these warnings the Biden Administration is doubling down with this destructive regulation engineered for short-term political points instead of responsible long-term energy planning.

In Virginia, the mismatch is magnified. While our surrounding states' power demand is projected to grow at 1 percent annually, Virginia's rapidly growing technology and advanced manufacturing sectors requires five times the generation supply growth. Our regulated utilities have recognized that due to flawed demand forecasting and the misguided approach to retirements mandated by the previous democrat-controlled General Assembly and Administration, Virginia now needs to bring online new natural gas plants to meet our energy needs. This proposal not only ignores this looming potential energy crisis but exacerbates the problem.

Equally concerning is the proposal's sole reliance on uncertain carbon-reducing technologies. While these technologies, and other innovations, are a promising part of our energy future, the predetermination of winners and losers and the arbitrary timelines will destabilize our energy system. This concern has already been realized in Virginia, with alarm bells being rung loudly by PJM and other transmission operators, yet the Biden proposal ignores commonsense policies yet again.

Let's not forget Winter Storm Elliot this past Christmas season, when only by activating fossil fuel plants that are slated for retirement under the Biden proposal, were we were able to keep the lights on. There is room for commonsense in energy planning.

The Biden Administration has not put forward a comprehensive energy plan and is wholly unprepared to support the changes to our infrastructure this transition requires. Whether it be the need to combat China's dominance of the critical minerals supply chain, deploy critical energy transmission infrastructure, remove regulations impeding carbon pipeline expansion and storage, or perform basic updates to an ineffective federal permitting system, this Administration has proven their misguided energy proposal is not ready for prime time.

The Biden Administration is also proposing this action despite the Supreme Court's decision in *West Virginia v. EPA*, which condemned the federal government's institution of energy policies that exceed Congress' authority. As the Court said in their opinion, "a decision of such magnitude and consequence rests with Congress itself, or an agency acting pursuant to a clear delegation from that representative body." This proposal ignores that clear directive.

American families and businesses already experience daily the burdens of this Administration's irresponsible energy plan, and this proposal further demonstrates a complete disregard for an affordable and reliable power future. I encourage the Biden Administration to abandon this proposal and the lasting damage it inflicts on America's energy and power future and begin a dialogue with the States and let us engage with the American public honestly on the complexities of energy planning that have been woefully ignored.

Sincerely,

Glenn Youngkin

Maintaining the PJM Region's Robust Reserve Margins

A Critique of the PJM Report:

Energy Transition in PJM: Resource Retirements, Replacements and Risks

May 2023

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WILSON ENERGY ECONOMICS

Prepared for

Sierra Club and Natural Resources Defense Council

Contents

I. Executive Summary

PJM Interconnection, LLC ("PJM") is the regional transmission organization ("RTO") that coordinates wholesale electricity markets in the Mid-Atlantic area ("PJM Region"). PJM has embarked on a multiyear effort to study the potential impacts associated with the evolving electric generation resource mix in the transition to cleaner forms of energy in the PJM region, resulting in a series of "Energy Transition in PJM" reports.[1] PJM's goal with this analysis has been to identify gaps and opportunities in PJM's current wholesale market constructs and offer insights into the future of market design, transmission planning and system operations.[2] The first two reports in this series presented scenarios of the changing resource mix out to 2050, identified generator operational characteristics that will be needed to reliably operate the future system, and called attention to the need to accurately assess the reliability contributions of all resource types, among other emerging issues.

The first two reports in PJM's Energy Transition in PJM series did not raise concerns or even discuss PJM Region "reserve margins" (the total amount of capacity to meet customers' peak loads reliably). However, PJM's recent, third report, *Energy Transition in PJM: Resource Retirements, Replacements and Risks*[3] ("R4 Report"), focuses on reserve margin calculations for 2023 to 2030. Despite a history of high reserve margins, the R4 Report's scenarios suggest that the region could face drastically low reserve margins, jeopardizing resource adequacy and reliability, in the transition to clean energy between now and 2030. The R4 Report anticipates low reserve margins based on "balance sheet" calculations that simultaneously assume strong load growth, a fast pace of retirements, and a slow pace of new entry.[4]

This paper reviews and critiques the R4 Report's resource adequacy calculations. I conclude that PJM's simple balance sheet calculations are invalid, as they combine highly contradictory assumptions that cannot occur together. The calculations ignore the simple reality, repeatedly demonstrated over the history of PJM's energy and capacity markets, that the pace of retirements and new entry are interconnected through the price signals of PJM's "RPM" capacity market and other markets, and consistently result in procuring more than enough capacity to maintain reliability. Whenever reserve margins decline, RPM prices rise, and the market soon responds with some combination of additional entry and delayed retirements, returning the system to higher reserve margins and moderate capacity prices. The capacity market has consistently and effectively procured more than sufficient capacity, as PJM has repeatedly concluded in its reports on RPM auction results.[5]

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[1] PJM, *Energy Transition in PJM: Frameworks for Analysis,* December 2021, available here; *Addendum*, available here; *Energy Transition in PJM: Emerging Characteristics of a Decarbonizing Grid*, May 2022, available here; *Addendum*, available here.

[2] See, for instance, *Energy Transition in PJM: Frameworks for Analysis,* p. 1.

[3] PJM, *Energy Transition in PJM: Resource Retirements, Replacements and Risks*, February 2023, ("R4 Report"), available here. The R4 Report was discussed with stakeholders at a special workshop on March 28, 2023; PJM's presentation at that meeting is available here. PJM also published a Frequently Asked Questions document on April 21, 2023 ("R4 Report FAQ"), available here.

[4] See, for instance, R4 Report page 16, presenting scenarios under which reserve margins fall to 7% or 8% by 2028 and "may be insufficient to cover peak demand expectations" even with demand response.

[5] See, for instance, PJM new release February 27, 2023, *PJM Capacity Auction Procures Adequate Resources*, p. 1 (quoting CEO Manu Asthana: "The capacity auction continues to be our best tool to ensure reliability at competitive prices in PJM").

If anything, the RPM capacity market is overly conservative. Reserve margins have chronically been excessive, as will be shown later in this paper. Reserve margins need to decline toward the target levels needed for adequate reliability, and likely will in the coming years. And PJM has additional tools at its disposal, ignored in the R4 Report, to help keep reserve margins at acceptable levels (such procurement through the RPM "incremental" auctions,[6] and the "reliability backstop" provisions.[7]) Based on the invalid calculations presented in the R4 Report, PJM has needlessly worried stakeholders and policy makers with drastically low reserve margin scenarios that are highly unrealistic, as I will further explain in this paper.

The R4 Report briefly acknowledges the important challenges associated with the anticipated changes in the resource mix,[8] and that PJM and stakeholders are working to address them.[9] The Winter Storm Elliott experience in December 2022 suggests the urgency of efforts to bolster plant performance under extreme cold, fuel security, and winter resource adequacy.[10] The unrealistic scenarios in the R4 Report suggesting very low reserve margins draw attention away from the important issues around winter resource adequacy and the changing resource mix, and could lend support to unnecessary and misguided policies aimed at retaining high-cost, high-emission power plants,[11] contrary to federal and state policies that seek to require low- or no-emission generation.

The remainder of this paper is organized as follows. The next section explains how PJM's RPM capacity construct creates price signals that have effectively guided retirement and new entry decisions over many years. Sections III and IV provide a critique of the R4 Report's balance sheet calculations and assumptions. The final section explains why it is important for resource adequacy analysis to be realistic.

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[6] RPM incremental auctions are held closer to the delivery year and afford PJM an opportunity to acquire additional capacity. See PJM Tariff Attachment DD Section 5.4.

[7] PJM Tariff Attachment DD Section 16, *Reliability Backstop* (providing that if RPM clears more than one percent below the target reserve margin PJM will investigate the causes and recommend corrective actions; and if this occurs for three consecutive delivery years PJM can hold a Reliability Backstop Auction to procure additional capacity).

[8] R4 Report p. 17 ("The composition and performance characteristics of the resource mix will ultimately determine PJM's ability to maintain the reliability of the bulk electric system.")

[9] R4 Report p. 17 ("Managing the energy transition through collaborative efforts of PJM stakeholders, state and federal agencies, and consumers will ensure PJM has the tools and resources to maintain reliability.")

[10] PJM's preliminary analysis of the Winter Storm Elliott event with substantial supporting information is available <u>here</u>. PJM expects to provide "lessons learned" from the event in May 2023 with a full report in July 2023.

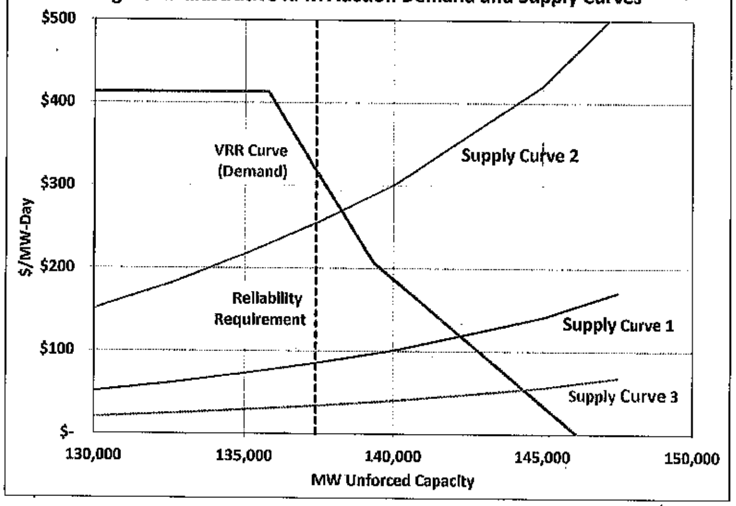
[11] As one recent example, see the *Commission Order* in West Virginia Public Service Commission Case No. 22-0793-E-ENEC, April 24, 2023, available <u>here</u>, pp. 7-9 ("Moreover, suggestions by some intervenors that there are no existing or expected reliability problems in PJM have recently been rejected by PJM. *[footnote citing to R4 Report]* In fact, PJM has recently studied the reliability quality of its near-term power supply and found that reliability is impacted by over-reliance on intermittent resources, mostly solar and wind... In addition to reserve margins that are far below the historical margins in PJM, the PJM Report 2023, shows that by 2026 all of the capacity reserves in PJM will be intermittent resources or voluntary customer curtailments, neither of which can be dispatched when needed as is the case with thermal generation resources.") citing the R4 Report, in support of a proposal to subsidize a coal-fired plant to keep it in operation one additional year, from June 1, 2023 to May 31, 2024).

II. Resource Adequacy, Reserve Margins and Capacity Prices in the PJM Region

One of PJM's core goals is to ensure that its wholesale markets will provide adequate total electric generating capacity to meet customer peak loads plus a "reserve margin," to account for plant outages and other uncertainties. PJM's wholesale energy and ancillary services markets, and related bilateral markets, are the main sources of revenue for generation on the PJM system, while PJM's Reliability Pricing Model ("RPM") capacity construct is intended to provide the additional, "missing money" needed to achieve resource adequacy targets.[12] Thus, RPM plays a pivotal role in ensuring resource adequacy; the R4 Report completely ignores this in its balance sheet calculations.

Under RPM, PJM holds annual auctions to acquire capacity commitments for the "delivery year" three years into the future (for example, the RPM auction held in May 2018 acquired commitments for the period from June 1, 2021 through May 31, 2022).[13] The RPM auctions use a sloped "demand curve" for capacity that is positioned based on PJM's forecast of future peak load plus the target reserve margin, and the capacity price that is considered needed to attract the construction of new power plants (this price parameter is called "Net CONE"). The capacity "supply curve" for each auction is based on price offers from the owners of eligible power plants and providers of demand response and energy efficiency resources. In the RPM auctions, the intersection of the sloped demand curve and the supply curve determines the capacity price, cleared quantity, and reserve margin for the future delivery year.[14] This is illustrated in Figure 1, in which "Supply Curve 1," shown in red, clears at about $120/MW-day.

Figure 1: Illustrative RPM Auction Demand and Supply Curves

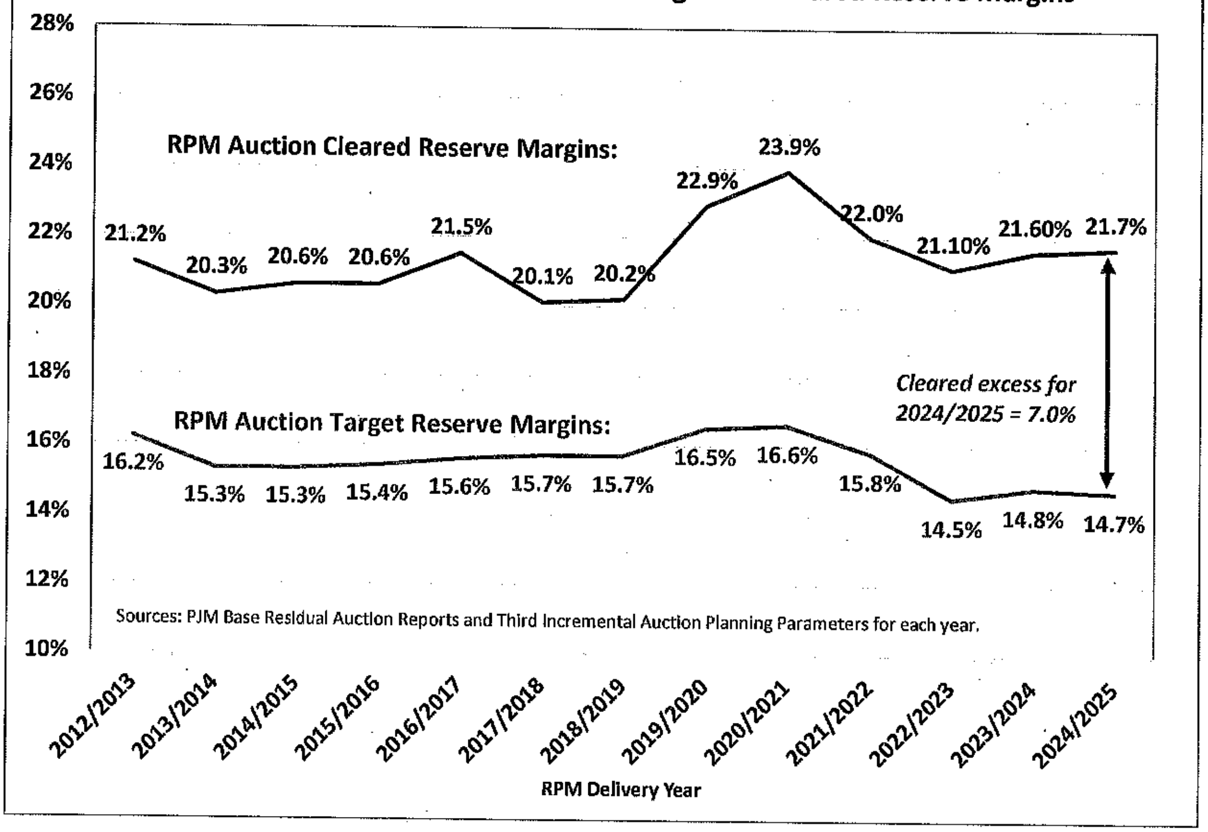


The sloped RPM demand curve results in clearing prices that signal whether additional capacity is needed on the PJM system. When capacity is relatively scarce or expensive (shifting the supply curve up and left; Supply Curve 2 in Figure 1), the sloped demand curve ensures that the auction will clear at a higher price, creating a price signal and incentive for market participants to delay retirements, upgrade existing plants, build new plants, and develop demand response. At times when capacity is abundant and low cost (shifting the supply curve down and right; Supply Curve 3 in Figure 1), as has been the case recently, the sloped demand curve results in RPM clearing more capacity and at a lower clearing price, which reduces incentives for new plants and encourages high-cost existing plants to retire..

[12] For a more extensive discussion of the importance of energy and ancillary services markets and the different roles of these markets and the capacity market see Wilson, James F., *"Missing Money" Revisited: Evolution of PJM's RPM Capacity Construct*, prepared for the American Public Power Association, September 2016, available here.

The RPM mechanism has worked in the past to maintain reserve margins at high levels. Figure 2 shows that while the target installed reserve margins for the RTO Region have generally been around 15% or 16% of the forecast peak load (the blue line in Figure 2), the RPM auctions have regularly cleared significantly more – reserve margins of 20% or more (red line). So while the target reserve margins of about 15% or 16% of peak load represent the capacity PJM believes it needs to reliably operate the system, RPM has consistently drawn commitments that are far in excess of these targets. Note that the actual reserve margins and excess capacity in the delivery year have been even larger, because the final load forecast and actual, weather-normalized peak loads are generally lower, and because thousands of MW of additional resources that fail to clear in each RPM auction nevertheless continue to operate as "energy-only" resources on the PJM system.

Figure 2: RPM Base Residual Auction Target and Cleared Reserve Margins



In a 2020 report, I explained that this over-procurement is a result of RPM auction design features and inaccurate peak load forecasts.[15] I also explained that the excessive capacity commitments and reserve

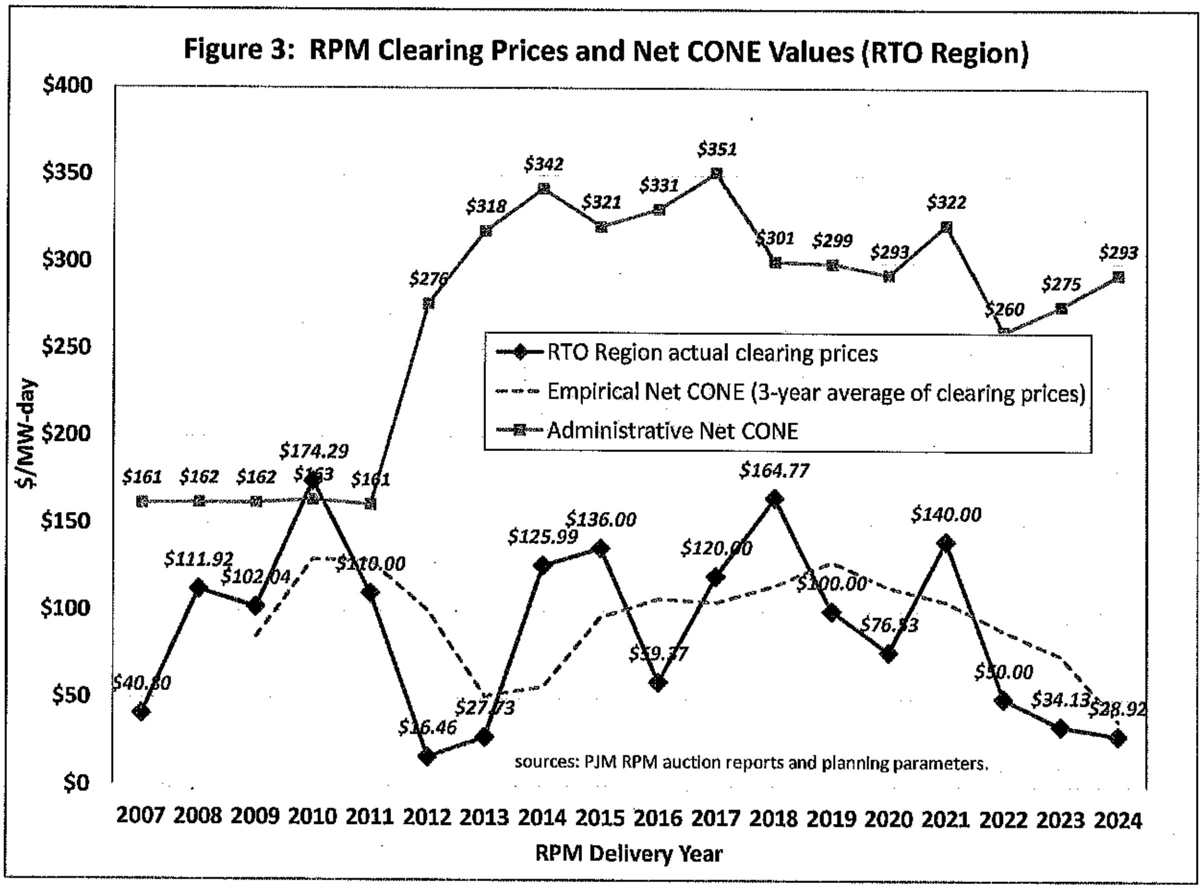
[13] Recent and upcoming auctions are less than three years forward due to delays that have occurred for various reasons. PJM intends to return to a three year forward schedule in a few years.

[14] The actual delivery year reserve margins can be somewhat different (usually higher) due to updated load forecasts and adjustments to capacity commitments through additional, "incremental" RPM auctions.

[15] Wilson, James F., *Over-Procurement of Generating Capacity in PJM: Causes and Consequences*, February 2020, prepared for Sierra Club and Natural Resources Defense Council ("Over-Procurement Report"), available here.

margins harm consumers and markets.[16] The over-procurement and excessive reserve margins have continued to the present, with the most recent RPM auction providing a 21.7% reserve margin for the 2024-2025 delivery year, far above the target of 14.7% for adequate reliability.[17]

As noted above, RPM auction reserve margins are linked to RPM capacity prices through the sloped demand curve used in the auctions; high reserve margins go with low capacity prices, and low reserve margins lead to high capacity prices. Figure 3 shows the history of RPM capacity prices for the RTO Region (blue line). Consistent with the high reserve margins shown in Figure 2, capacity prices have generally been rather low, and far below the administrative Net CONE values (shown in red in Figure 3) that are supposed to represent the prices needed to attract new entry.



The RPM mechanism has worked to maintain high reserve margins despite various stresses that have arisen from time to time. As an example of the mechanism at work, the PJM Region experienced a wave of retirements in the 2012 to 2015 time frame, largely driven by emissions regulations, when close to 22,000 MW retired.[18] Despite these retirements, PJM reserve margins remained high (as shown in Figure 2), primarily due to the construction of a similar quantity of new gas-fired power plants in the PJM region

[16] Over-Procurement Report, pp. 10-13.

[17] PJM, *2024/2025 RPM Base Residual Auction Results*, available here (stating at p. 2 that the RPM auction result represents a 21.7% reserve margin for the PJM region, compared to the resource adequacy target of 14.7%).

[18] R4 Report p. 6.

at about the same time.[19] The market functioned as intended, encouraging new, more efficient plants to replace older, uneconomic ones.

Figure 3 also shows that following RPM auctions that result in relatively high prices, the auction price has always declined sharply the following year, suggesting that market participants react quickly to RPM price signals (and also to changes in RPM demand, and to changes in energy price expectations), increasing supply to bring prices back to moderate levels. RPM prices for the RTO Region have risen above $130/MW-day four times in the eighteen years shown in Figure 3 (in 2010, 2015, 2018, 2021), and in each instance the price fell by over $60/MW-day the following auction, to an average of $80/MW-day. This dynamic has resulted in capacity prices that have been relatively stable on three-year-average basis, as shown in Figure 3 (green dashed line), and reserve margins that have been well above targets, as shown in Figure 2. RPM has been shown over eighteen years to be quite robust and resilient.

It is worth noting that for RPM to clear near the target reserve margin, the capacity price would have to rise to over $300/MW-day on the sloped demand curve, roughly ten times recent clearing prices.[20] This huge increase in the capacity price would serve as a very strong incentive for relatively more new entry and for delay of retirement plans, despite the reserve margin being near the target.

Figures 2 and 3 show that RPM has consistently cleared very high reserve margins at prices well below Net CONE, including in the most recent auction held in February 2023 for the 2024/2025 delivery year. The causes of over-procurement, discussed in my 2020 report, have only partially been corrected at this time.[21] Thus, it is important to keep in mind going forward that if reserve margins decline toward target levels, raising capacity prices, this will bring the results closer to the desired procurement, which will be beneficial to consumers and the markets. The R4 Report worries that "For the first time in recent history, PJM could face decreasing reserve margins…";[22] if so, this would represent a needed correction rather than present a cause for concern.

Looking forward, there will be more retirements, perhaps even the R4 Report's estimate of 40 Gigawatts ("GW") through 2030,[23] as federal and state policies encourage moving away from high-cost and high-emitting resources. However, PJM's generation interconnection queues reflect a far greater quantity of potential new resources: over 17 GW of natural gas-fired resources, and over 200 GW of renewable and renewable-storage hybrid resources.[24] The changing resource mix in PJM, as in other regions across North America and around the world, will necessitate changes to market mechanisms and planning methods to accommodate the new resources while maintaining reliable operations, as the earlier reports in the

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[19] This same observation (that the retirements during this period were matched by new entry) was made by PJM in its October 18, 2022 report in response to questions posed by the Federal Energy Regulatory Commission in FERC Docket No. AD21-10, *Modernizing Wholesale Electricity Market Design*, p. 38.

[20] See, for instance, PJM, *Planning Period Parameters for the 2024-2025 Base Residual Auction*, available here.

[21] Over-Procurement Report pp. 4-10; see also Wilson, James F., *Affidavit in Support of the Comments of the Public Interest Entities*, filed October 21, 2022 in FERC Docket No. ER-22-2984 (RPM Quadrennial Review), pp. 7-15.

[22] R4 Report p. 17.

[23] R4 Report p. 17.

[24] R4 Report p. 2.

Energy Transition in PJM series discussed. The final section of this paper identifies the PJM stakeholder processes that are addressing these challenges.

III. Critique of the R4 Report's "Balance Sheet" Reserve Margin Calculations

In this context of a long history of over-procurement, high reserve margins, and moderate capacity prices, PJM released its R4 Report with "balance sheet" resource adequacy calculations to 2030. Balance sheet calculations are common in the Integrated Resource Plan filings of vertically integrated utilities, where they are typically used to show the amount of additional capacity that the utility, as the sole or central planner of capacity for its service territory, must build or acquire to keep reserve margins at target levels. Balance sheet calculations will typically show the capacity the utility expects to have available over the coming years (reflecting current resources, retirements, and new additions), and its demand for capacity (based on a peak load forecast net of demand-side resources). Comparing the projected available capacity before additions to the projected demand for capacity results in projected reserve margins; Table 1 provides an example. Utilities may also apply the balance sheet method to evaluate scenarios of higher demand or fewer resources in order to identify when capacity additions may be needed. Thus, balance sheet calculations can be a useful communication tool under circumstances where a single entity is responsible for planning the future capacity balance.

Table 1: Example of "Balance Sheet" Reserve Margin Calculations
(Table 8 From Oklahoma Gas & Electric's 2021 Integrated Resource Plan)

Table 8 – Planning Reserve Margin (MW unless noted)

Capacity	Owned Capacity	6,702	6,534	6,534	6,323	6,259	5,856	5,856	5,856	5,856	5,371
	Purchase Contracts	47	47	47	47	47	47	47	47	47	16
	Total Capacity	6,749	6,581	6,581	6,370	6,306	5,903	5,903	5,903	5,903	5,386
Demand	Demand Forecast	6,303	6,313	6,379	6,431	6,491	6,543	6,589	6,626	6,630	6,659
	OG&E DSM	278	309	340	372	403	432	456	477	494	505
	Net Demand	6,025	6,004	6,039	6,059	6,088	6,111	6,133	6,149	6,136	6,154
Margin	Reserve Margin[12]	12%	10%	9%	5%	4%	-3%	-4%	-4%	-4%	-13%
Needs	Needed Capacity	0	145	183	417	514	942	967	985	970	1,507

The R4 Report refers to the application of a balance sheet approach in multiple places,[25] however, the balance sheet calculations were not provided, only the reserve margin results (R4 Report Table 1, reproduced here).[26] The reserve margin results were provided for the R4 Report's two new entry scenarios and two load forecast scenarios. Referring to the reserve margin calculations, the R4 Report states (pp. 16-17), "By the 2028/2029 Delivery Year and beyond, at Low New Entry scenario levels, projected reserve margins would be 8%... For the first time in recent history, PJM could face decreasing reserve margins, as shown in Table 1, should these trends – high load growth, increasing rates of generator retirements, and slower entry of new resources – continue."

[25] R4 Report pp. 2, 3, 4, 17.

[26] R4 Report FAQ #2 ("A data annex will not be provided given market-sensitive and licensing issues related to the content of the study.")

The fundamental and fatal flaw in PJM's balance sheet calculations is the simple fact that it ignores how PJM has designed its own wholesale markets, and in particular its RPM capacity market, to work. The projected lower reserve margins cannot occur without causing much higher capacity prices (as explained in the prior section, due to the sloped RPM demand curve). Higher capacity prices lead to slower retirements, faster new entry and higher reserve margins. The R4 Report makes calculations using projections of retirements, new entry, reserve margins and capacity prices that are contradictory in the context of PJM's RPM and other wholesale markets; as a result, the results presented in the R4 Report are not plausible or possible.[27]

Table 2: The R4 Report's Table 1 "Balance Sheet" Results (page 16)

Table 1. Reserve Margin Projections Under Study Scenarios

Reserve Margin	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	23%	19%	17%	15%	11%	8%	8%	5%
Electrification	22%	18%	16%	13%	10%	7%	6%	3%
High New Entry								
2023 Load Forecast	26%	23%	21%	19%	17%	16%	17%	15%
Electrification	25%	22%	20%	18%	15%	14%	14%	12%

Table 3 provides estimates of the RPM capacity prices that would result from the balance sheet reserve margins presented in Table 1 of the R4 Report shown above.[28] Under PJM's Low New Entry scenario that is projected to lead to an unprecedented[29] 15% reserve margin for the 2026 delivery year, the RPM clearing price would have to rise to approximately $338/MW-day, or ten times the prices in recent auctions. Even under the High New Entry scenario, the projected reserve margins correspond to much higher capacity prices in 2026 and beyond, which would stimulate additional new entry and delay of retirements.

The R4 Report assumed capacity prices would remain at recent low levels[30] even while reserve margins decline due to the fast pace of retirements and slow pace of new entry. These assumptions – a fast pace of retirements, a slow pace of new entry, low reserve margins and low capacity prices – are simply contradictory and ignore the basic market dynamic that ensures resource adequacy in the PJM region.

[27] R4 Report FAQ #22 acknowledges this flaw ("Does this report consider the price-signaling function of the capacity market? This study did not intend to forecast future capacity prices and its retention of existing capacity in the 2025–2030 time period as capacity margins are forecast to tighten.")

[28] The estimated RTO Region capacity prices shown in Table 3 are based on the corresponding reserve margins in the R4 Report's Table 1, the applicable RPM base residual auction demand curve shapes for future years (the shape changes in 2026-2027 as a result of the recent Quadrennial Review) and Net CONE set to $250/MW-day.

[29] The lowest RTO Region reserve margin resulting from an RPM base residual auction was 16.5% in 2010/2011. This was based upon a load forecast that was later substantially lowered, leading to a higher delivery year reserve margin. Since 2012/2013 all base residual auction reserve margins have been 20% or higher, as shown in Figure 1.

[30] R4 Report p. 10.

Lower reserve margins cannot occur without the much higher capacity prices that would lead to delays in retirements and a faster pace of new entry.[31]

Table 3: Capacity Prices Corresponding to The R4 Report's Reserve Margin Projections								
$/MW-day	2023	2024	2025	2026	2027	2028	2029	2030
Low New Entry								
2023 Load Forecast	$34.13	$28.92	**$179**	**$338**	**$438**	**$438**	**$438**	**$438**
Electrification	$34.13	$28.92	**$235**	**$438**	**$438**	**$438**	**$438**	**$438**
High New Entry								
2023 Load Forecast	$34.13	$28.92	**$56**	**$64**	**$173**	**$251**	**$173**	**$338**
Electrification	$34.13	$28.92	**$87**	**$118**	**$338**	**$424**	**$424**	**$438**

Note: For 2023 and 2024, RTO Region prices from the applicable RPM base residual auctions are shown; for 2025 to 2030, the capacity prices were estimated based the corresponding reserve margins in the R4 Report's Table 1, the applicable RPM base residual auction demand curve shapes for future years (the shape changes in 2026-2027 as a result of the recent Quadrennial Review) and Net CONE set to $250/MW-day.

The R4 Report's reserve margin scenarios are unrealistic for additional reasons. Market participants are continually assessing all of PJM's markets and the potential need for resources, and planning retirements and new entry accordingly.[32] Whatever the capacity price might be, a decline in the reserve margin would also lead to expectations of relatively less supply and higher prices in forward energy markets, raising expectations for future revenue opportunities and encouraging market participants to retain existing resources and plan new ones.

IV. Critique of the R4 Report's Retirement, New Entry, and Peak Load Projections

While the fundamental flaw in the R4 Report's calculations is the neglect of market dynamics and use of contradictory assumptions, this section of the paper also comments on the details of the retirement, new entry, and load forecast projections. These projections are highly conservative; that is, they reflect a fast pace of retirements, a slow pace of new entry, and increases in peak loads that are highly speculative.

1. The Assumed Fast Pace of Retirements Could Occur Only if Reserve Margins Remain High

The R4 Report estimated annual retirements to 2030 based on a combination of various federal and state policies and also "economics" (estimated profitability based on energy and capacity price assumptions).[33] Much of the older and less efficient capacity on the PJM system retired over the 2012 to 2022 period; a

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[31] PJM's own consultant, The Brattle Group, has made this point very clearly on various occasions. See, for instance, *Written Testimony of Dr. Kathleen Spees and Dr. Samuel Newell, Economic Impacts of the Expansive Minimum Offer Price Rule within the PJM Capacity Market*, filed August 20, 2021 in FERC Docket No. ER21-2582, pp. 19-20 Section C.3 ("Capacity Markets with Sloped Demand Curves Cannot Simultaneously Produce Low Prices and Poor Resource Adequacy.")

[32] For a more extensive discussion of the evidence that market participants are reacting to market conditions see, for instance, Wilson, James F., *Affidavit in Support of the Protests of DC-MD-NJ Consumer Coalition, Joint Consumer Advocates, and Clean Energy Advocates*, filed May 7, 2018 in FERC Docket No. ER18-1314, pp. 11-16.

[33] R4 Report pp. 5-10.

total of 47.2 GW, according to the R4 Report.[34] The R4 Report generally assumes the remaining plants considered at risk of retirement will be rather quick to choose retirement, with an additional 40 GW retiring over 2022 to 2030.[35] This is similar to the pace of retirements over the 2012 to 2022 period.

The R4 Report identifies retirement dates as driven by policy, economics, or a combination of policy and economics, with 10 GW in the last category. In the workshop to discuss the report, PJM staff acknowledged that the R4 Report's analysis generally assumed retirements would occur at the earliest dates suggested by policy or economics, while for many of the resources there is some flexibility for the retirements to occur later, especially if reliability is jeopardized.[36] The R4 Report also did not consider that in many instances the owners could keep the capacity in operation through fuel switching or additional environmental investments.

As an example of the R4 Report's conservative assumptions, the R4 Report assumes 4.4 GW of retirements in 2026 associated with the U.S. Environmental Protection Agency's Good Neighbor Plan, which limits emissions of nitrogen oxides from facilities in certain states to protect against harmful ozone pollution in downwind states.[37] Reducing these emissions typically involves the installation of well-established selective catalytic reduction technology. While the Good Neighbor Plan involves emission-trading programs to increase flexibility for the regulated industry, the R4 Report assumed that every electric generating facility that would face costs under the rule would retire. The report noted that EPA would finalize this rule on March 15, 2023; in fact, EPA's analysis accompanying the final rule finds that only 1.4 GW of generation in PJM would retire, on net, as a result of the rule; [38] and PJM acknowledges that the final rule moves the retirement date to 2030.[39] While PJM couldn't know the details of a forthcoming rulemaking, its overly conservative approach of assuming that every unit facing costs under the rule would retire, *and* its failure to timely update its report after publication of EPA's rule, contribute to an overall inaccurate picture of how the PJM generation fleet is likely to change over the coming decade.

The low prices in the last three RPM base residual auctions – $50.00, $34.13, and $28.92/MW-day for the RTO Region – to some extent result from recent substantial increases in energy prices and price expectations;[40] higher energy prices lead to lower needs for capacity revenue. However, the low capacity prices also show that the owners of existing capacity are not in a hurry to retire their resources.

[34] R4 Report p. 6.

[35] R4 Report p. 2.

[36] See, for instance, R4 Report FAQ #11, acknowledging that many of the policies studied in the report have "safety valve" provisions that would enable plants to operate additional years for reliability purposes.

[37] R4 Report page 7.

[38] U.S. Environmental Protection Agency, Resource Adequacy and Reliability Analysis, Technical Support Document (TSD) for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards at Table. C4 (Mar. 2023), available here (showing 1.9 GW of coal retirements incremental to the base case in 2030, offset by fewer retirements among nuclear and other steam resources).

[39] R4 Report FAQ #12 (acknowledging that the final Good Neighbor Rule "moves the estimated retirement date of 4.400 MW from 2026 to 2030.")

[40] While peak period energy prices in PJM West have averaged well under $50/MWh for many years, forward prices are now over $60/MWh for 2025 through 2028.

Throughout the entire history of RPM we have repeatedly seen owners continue to operate even uneconomic resources, and even when the resources fail to clear in RPM and earn capacity revenue.

In addition to the large amount of capacity willing to accept quite low capacity prices, there has been over 9,000 MW of additional generation that offered but failed to clear in the auction in each of the last eleven RPM base residual auctions, and over 18,000 MW of uncleared generation in four of the last six auctions.[41] Much of this uncleared capacity does not retire. PJM's sensitivity analysis of the results of the most recent auction (for 2024-2025, which cleared at $28.92/MW-day) shows that removing 6,000 MW of low-cost supply from the supply curve for the RTO region would have reduced the total cleared quantity in the auction by less than 900 MW, and it would have raised the clearing price only to $56.26/MW-day; that is, a large amount of the uncleared capacity in the auction was also willing to accept quite low capacity prices.[42] While the pace of retirements may increase and reduce the current capacity overhang, this tendency for many owners to prefer to hold on for additional years if they have the flexibility to do so is unlikely to fundamentally change. Continued operation may entail losses, but once the retirement process is begun it is hard to reverse, and there is always hope that market conditions will improve.

It is also worth noting that with each announced retirement, the owners of other marginally economic plants will update their models to reflect the absence of the retiring plant, which will raise their expectations of energy and capacity prices and profits and make holding on another year more attractive. Developers of new plants will also update their models when a retirement is announced, which may lead them to accelerate their plans. Each announced retirement contributes to other marginal plants possibly holding on longer, and new projects possibly arriving sooner.

In addition, when a large plant retires, it leaves behind a local transmission system capable of delivering generation at that location to loads. New generation at or near the site can take advantage of the existing transmission capacity, which can both speed interconnection and lower its cost. The R4 Report's pessimistic retirement and new entry projections do not recognize this interaction, so this is an additional way the R4 Report's assumptions are both pessimistic and contradictory.

Note also that to the extent retirements are driven by state or federal policies, these policies are typically in place years in advance of the specified deadlines, so the market has plenty of time to anticipate the reduction in capacity and to plan replacements. This dynamic was seen in the wave of retirements over 2012-2015 that was matched with new entry and did not lead to declining reserve margins, as noted above. The EPA Good Neighbor policy and the Illinois Climate and Equitable Jobs Act contain 2030 deadlines, allowing plenty of time for the market to anticipate the reductions and plan replacements.

So while perhaps the rapid pace of retirements reflected in the R4 Report's retirement scenario could happen, the rapid pace would only occur in an environment of low capacity prices. But capacity prices can remain low only if reserve margins remain high, due to some combination of slow load growth and ample new entry. Accordingly, the R4 Report's retirements scenario either won't occur, or will occur with adequate reserve margins, contrary to the R4 Report's Table 1.

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[41] PJM, 2024-*2025 RPM Base Residual Auction Report*, Table 6, available here.

[42] PJM, *Scenario Analysis for Base Residual Auction*, Scenario # 4 (remove 6,000 MW of supply from bottom of supply curve in region outside of MAAC), available here.

2. The Assumed Slow Pace of New Entry Could Occur Only if Reserve Margins Remain High

The R4 Report notes the enormous amount of capacity currently in PJM's interconnection queues – 290 GW – but estimated that only a tiny fraction of this capacity will actually be built, applying "commercial probabilities" of projects coming into service based on historical data.[43] Renewable capacity was further adjusted to reflect its resource adequacy value.[44] While there is presently 270 GW of renewable capacity in the queue, this was reduced to 13.2 GW of new capacity by 2030, and only 6.7 GW in capacity value terms.[45] Of the 17.6 GW of natural gas projects in the queue, of which 12 GW already have signed Interconnection Service Agreements, the R4 Report assumed only 3.8 GW would be built.[46] The R4 Report states that these pessimistic assumptions were "augmented" based on scenarios from S&P Global's North American Power Outlook, and additional capacity was added, however, no details were provided about how the assumed total quantity of new entry was determined.[47] It is unclear to what extent the Low and High New Entry Scenarios presented in the R4 Report reflect the low historical commercial probabilities of renewable resources or take into account the improving economics of such resources.[48]

The low historical commercial probabilities are based on a period of chronic over-forecasting of load, chronic high reserve margins, and low need for new entry. In the past, developers added projects to the interconnection queue only to see the need for the capacity evaporate as the load forecast was lowered and RPM cleared very high reserve margins. The R4 Report also assumed Demand Response (capacity provided by demand-side resources) would remain at current levels, despite its projection of declining reserve margins.[49] Were reserve margins to decline at all, the rate of project completions would very likely rise considerably, and additional demand response would develop. PJM's assumed very low rate of completion of renewable resources in the queue, especially under its Low New Entry scenario, also ignores the strong incentives put in place last year with the Inflation Reduction Act.[50]

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[43] R4 Report pp. 11-12.

[44] Effective Load Carrying Capacity ("ELCC") fractions were applied, to reflect the likely contributions of resources to resource adequacy at times of system stress. The R4 Report used readily available capacity accreditation values from recent PJM reports, which are based on an average approach rather than the marginal approach PJM has proposed in the stakeholder process. However, this choice has little or no impact on the R4 Report's calculations, because reliability requirements are calculated based on actual plant performance, they do not use accreditation values. If accreditation values decline (as they typically do for some resources under a marginal approach compared to an average approach) the reliability requirement to satisfy a resource adequacy criterion, expressed in terms of the new accreditation approach, declines in a corresponding manner.

[45] R4 Report pp. 11-13.

[46] R4 Report p. 11.

[47] R4 Report p. 11.

[48] R4 Report FAQ #20 asked "How were the New Entry Scenarios Created"; the response referred to "a blend of the commercial probability analysis and the S&P Global Forecast," without providing further details.

[49] R4 Report FAQ #25.

[50] The Inflation Reduction Act provides long-term certainty for the Investment Tax Credit and Production Tax Credit, bonuses for locating in "energy communities" where coal-fired plants have retired, and many other new policies to encourage clean resources and energy storage.

A "High New Entry" scenario was also constructed,[51] based upon S&P Global's North American Power Outlook, Fast Transition sensitivity case.[52] Details of the Fast Transition scenario were also not provided and are not publicly available. However, a public Executive Summary shows that the focus was on 2050, with very little of the "fast transition" occurring by 2030, the end date of the period represented in the R4 Report.[53]

It is unclear to what extent PJM's projections under the High New Entry case account for state policies that aim to support development of new clean energy resources through renewable portfolio standards, procurement targets, and policies to support development of the transmission needed to bring these resources online. The R4 Report states that the S&P Global Fast Transition case "assumes carbon net neutrality by 2050 through the IRA and additional policies, such as state clean energy policies."[54] The reliance on a proprietary, nontransparent model to account for state clean energy policies is not reassuring that the contributions of those policies has been reflected. As a result, PJM comprehensively examined how state policies could affect retirements, but considered how federal and state policies could affect new entry to a lesser extent, thus creating a skewed analysis and perception of the overall impacts of policy action.

As with the R4 Report's retirements assumptions, while perhaps the rather slow pace of new entry reflected in the R4 Report's scenarios could happen, this could only happen in an environment of low capacity prices. But capacity prices can remain low only if reserve margins remain high, due to some combination of slow load growth and delayed retirements. Accordingly, these new entry scenarios either won't occur, or will occur with adequate reserve margins, contrary to the R4 Report's Table 1.

3. The Forecast of Rapidly Rising Peak Loads is Highly Speculative

The R4 Report used two RTO peak load forecasts that both suggest sharply rising peak loads; one from PJM's 2023 load forecast report ("2023 Forecast"), and another, much higher forecast to reflect faster electrification and additional data center loads.[55]

The PJM 2023 Forecast projects that RTO region summer peak loads will rise from recent levels under 150,000 MW to nearly 158,000 MW by 2030 (Figure 4). However, since 2008 through 2022, RTO peak loads have actually been trending downward or flat, as shown in Figure 4.[56]

[51] R4 Report p. 12.

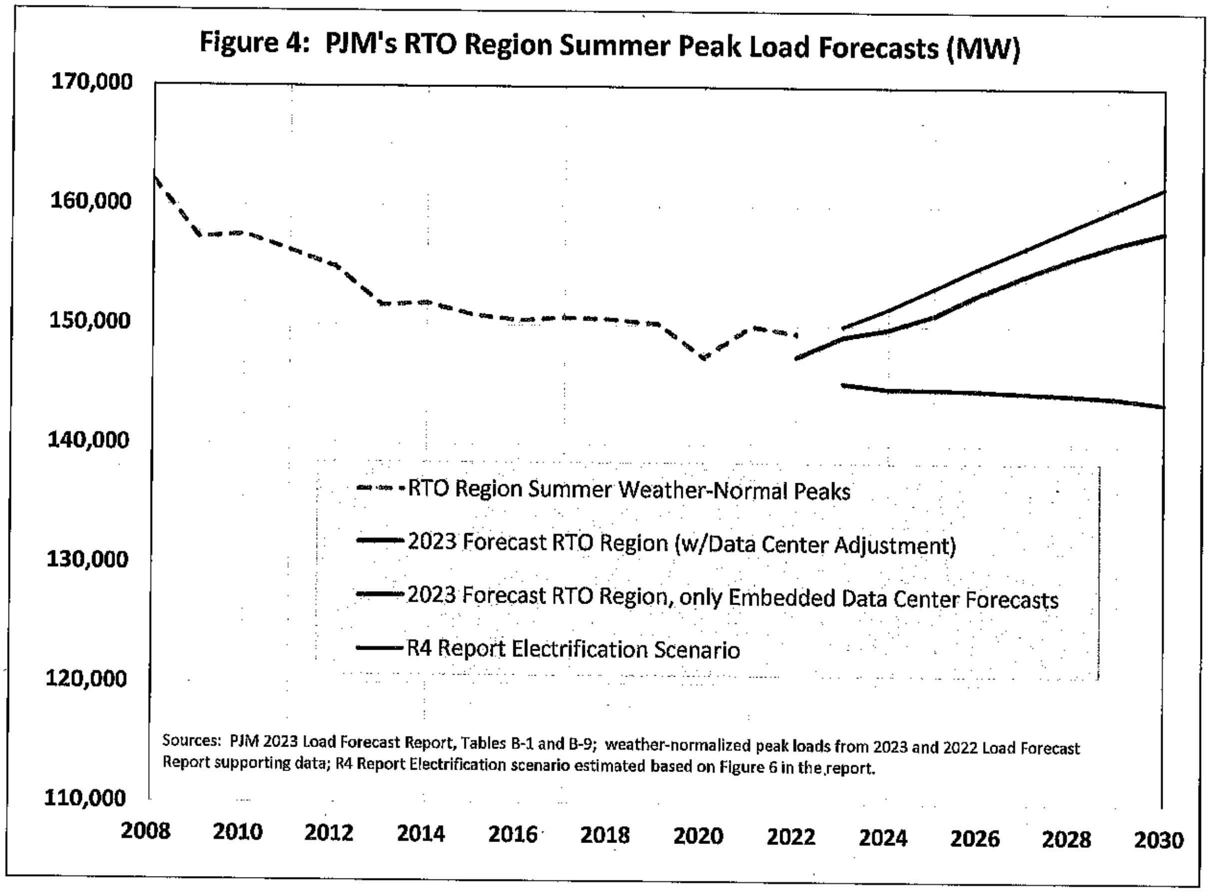
[52] S&P Global, North American Power Outlook Fast Transition sensitivity case, Executive Summary available here.

[53] S&P Global, North American Power Outlook Fast Transition sensitivity case, Executive Summary, page 5 (showing the U.S. generation mix to 2050, with the vast majority of the change occurring after 2030).

[54] R4 Report p. 12 footnote 20.

[55] R4 Report pp. 14-15.

[56] The figure shows historical peak loads on a "weather-normalized" basis: PJM's estimates of what the peak load would have been under typical peak day weather. This removes the impact of the actual weather in each year, which may have been hotter or less hot than the typical weather on the peak day, and reveals the underlying trend in the peak loads.



Over many years, PJM has consistently (and incorrectly) forecasted that peak loads would rise.[57] PJM has recently made changes to its forecasting methodology that should improve accuracy, and recent forecasts (before the 2023 Forecast) have been flatter and more consistent with the recent trend. The PJM 2023 Forecast only increases due to the inclusion of a highly speculative projection of future data center construction.[58] While data center load i n PJM was under 4,000 MW in 2022, PJM's 2023 forecast assumes it grows to over 25,000 MW in 2038.[59] Beyond about 2027 or 2028, this forecast of data center construction, which is provided to PJM by Dominion Energy and other utilities,[60] is speculative and not supported by contractual commitments. In the past PJM was unwilling to include in its forecasts

[57] For a "rooster graph" of PJM's past load forecasts see Wilson, James F., *Affidavit in Support of the Comments of the Public Interest Entities*, filed October 21, 2022 in FERC Docket No. ER22-2984 (RPM Quadrennial Review), p. 13, available here.

[58] R4 Report pp. 14-15.

[59] PJM, *2023 Load Forecast Supplement*, available here, pp. 18-20.

[60] PJM, *2023 Load Forecast Supplement*, p. 20 (noting that this year, PJM requested of Dominion a long-term data center forecast).

speculative future data center construction beyond five years out;[61] PJM now accepts such speculation and relies on it as the basis for its forecast of rising rather than falling peak loads.

The lower, purple forecast line in Figure 4 shows PJM's forecast before the addition of the speculative data center amounts. This is PJM's forecast based on its load forecasting methodology and model, which includes a projection of future increases in data centers loads based on the historical trend in these loads.[62] With only such "embedded" data center growth, PJM's forecast continues to decline, consistent with the 15-year trend, although the decline is at a slow rate.

The R4 Report's balance sheet calculations also evaluate an even more speculative load forecast scenario that includes very aggressive assumptions about the peak load impacts of electrification, and may include yet more speculative data center loads (the highest, black line in Figure 4). The R4 Report confusingly describes this scenario as reflecting "updated electrification assumptions and accounting for new data center loads," even though the 2023 Forecast, documented in the 2023 load forecast report (the red line in Figure 4), already includes a very large upward adjustment for data center construction, as discussed above.

The electrification and additional data center assumptions reflected in this additional, extreme load scenario were never discussed with the PJM Load Analysis Subcommittee.[63] Furthermore, even if electrification moves rapidly forward in the PJM Region, state and federal policies, and PJM's market rules, will likely be modified to ensure that the impact on peak loads and capacity prices is mitigated by time-of-use pricing and other provisions to shift loads away from summer and winter peak hours.[64]

The current boom in data center construction is likely to continue for at least the next few years, however, it is uncertain how long this boom will continue, and to what extent new data centers will be located in the PJM footprint rather than elsewhere. In any case, PJM's data center scenarios, while highly

[61] See, for instance, PJM, *Dominion Data Center Adjustment for the 2018 Load Forecast Report*, p. 2 ("Projections are not available after 2022, so the assumption was made to keep data center load flat in the out year.") This file has been removed from the PJM web site.

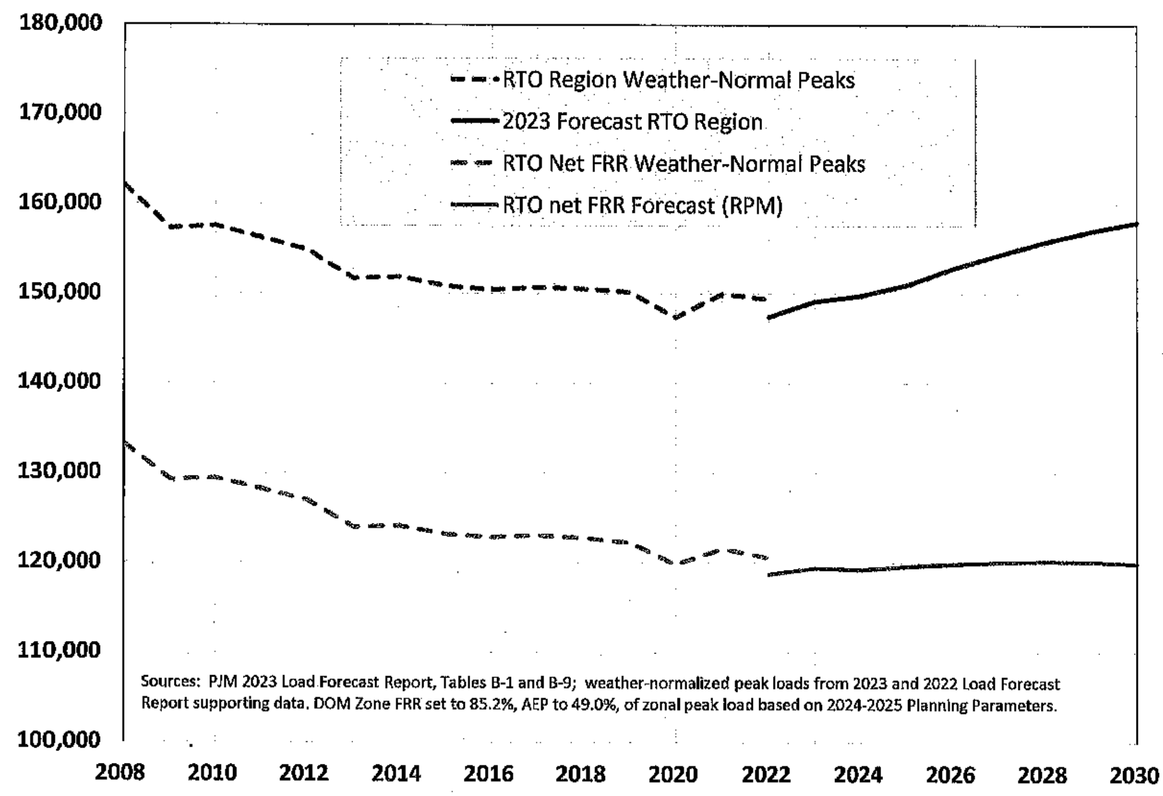
[62] PJM, PJM Load Forecast January 2023, Tables B-1 and B-9.

[63] See, for instance, PJM, *2023 Preliminary PJM Load Forecast*, Load Analysis Subcommittee, November 29, 2022, p. 22 (showing a very small addition for EVs), p. 29 (mentioning "electrification" at the end of the presentation as an "Area of Focus" in 2023.

[64] For example, Illinois CEJA contains numerous requirements to address peak demand, such as requiring the Illinois Commerce Commission to establish a performance metric for peak load reductions attributable to demand response programs, 220 ILCS 5/16-108.18(e)(2)(A)(ii), and requiring utilities to develop beneficial electrification plans that include efforts to reduce increases to peak demand, 220 ILCS 627/45(a). The Virginia State Corporation Commission has required Dominion and APCo to file transportation electrification plans that include assessments of the impact of transportation electrification on peak loads, and evaluate the need for managed charging and time of use tariffs to maximize grid benefits. Commonwealth of Virginia, ex rel. State Corporation Commission Case No. PUR-2020-00051, Ex Parte: Electrification of Motor Vehicles, Order Directing the Filing of Transportation Electrification Plans (June 15, 2022). The New Jersey Board of Public Utilities has proposed to limit incentives for medium and heavy-duty vehicle charging facilities to entities that "agree to participate in a managed charging program that directs most charging to off-peak periods." Notice in the Matter of Medium and Heavy Duty Electric Vehicle Charging Ecosystem, available here. In addition to these recent efforts by states to limit peak demand growth, there are many examples of retail rate designs to incentivize off-peak charging of electric vehicles. See, for instance, Baltimore Gas & Electric, EVsmart® Vehicle Charging Time of Use Rate, available here; PEPCO's Residential Time-of-Use Rate, available here.

speculative, are also largely irrelevant to PJM's resource adequacy analysis and RPM capacity market. The vast majority of the projected data center load is in the Dominion zone, where nearly all capacity is planned under a Fixed Resource Requirement ("FRR") plan outside of RPM by Dominion Virginia Power, a vertically-integrated utility.[65] Thus, whether or not data center loads will continue to increase in Virginia may be a concern for Dominion Virginia Power for its upcoming 2023 Integrated Resource Plan, and for Dominion's stakeholders and the Virginia Corporation Commission, such growth will have little affect on RPM requirements or clearing prices. Figure 5 shows an estimate of the RTO Region 2023 load forecast that PJM will use for future RPM auctions, where the FRR amounts in the Dominion Zone (about 85% of the zonal peak load), and the AEP Zone (wheere FRR is about 49%) have been removed.

Figure 5: RTO Region Summer Peak Load for RPM (Net DOM, AEP FRR; MW)



It is also the case that data centers require a high level of reliability, which they self-provide with on-site backup generation; they do not solely rely on the grid for reliability. The data centers may not be eligible to monetize their backup capacity as Demand Response capacity in RPM or through the Dominion FRR plan due to environmental regulations, capacity market rules, or other barriers. However, the owners

[65] See, for instance, PJM, *2024/2025 RPM* Base *Residual Auction Planning Period Parameters,* p. 1 footnote 2: "The total UCAP Obligation of all Fixed Resource Requirement (FRR) Entities is subtracted from the PJM RTO Reliability Requirement, and any applicable LDA Reliability Requirement, when determining the target reserve levels to be procured in each RPM BRA"; and the associated excel file, showing that nearly all of the Dominion zone load is FRR; these files available here.

would generally be willing to run their backup generators to prevent load shed if asked by PJM to do so, and if legally permitted to do so.

V. Why It's Important to Realistically Assess Resource Adequacy Risk

As noted in the opening paragraph of this paper, PJM has issued two earlier reports in preparation for the transition to cleaner forms of energy in the PJM Region, and is working collaboratively with stakeholders and state and federal authorities on its Energy Transition in PJM effort. The R4 Report can be understood to suggest that federal and state policies encouraging the closure and replacement of uneconomic and high-emitting power plants are creating a reliability problem. While PJM asserts that the intent of the R4 Report was to "inform discussions,"[66] the R4 Report's false alarm around future reserve margins is potentially a setback on the road to preparing for the transition in the resource mix.

This paper has shown that the existing PJM market mechanisms are robust, so retirements and new entry are likely to occur at paces consistent with resource adequacy. While there are many actions on the To Do list for future years, actions to encourage further operation of uneconomic power plants should not be one of them. To maintain resource adequacy and reliability, the priorities have been and should remain as indicated in PJM's two earlier Energy Transition reports and in various current PJM stakeholder processes:

- To get the generation interconnection queues moving again to allow new generation projects to move forward in a timely manner (PJM Interconnection Process Subcommittee).[67]
- To enhance winter risk analysis and bolster winter resource adequacy, including lessons learned from Winter Storm Elliott. This involves ensuring that resource accreditation reflects extreme conditions and correlated and upstream causes of outages, strengthening the incentives for winterization and fuel security, and enhancing the capacity market rules to procure a portfolio of resources that provides adequate winter resource adequacy (Critical Issue Fast Path process, Resource Adequacy Senior Task Force).
- To address various other resource adequacy and RPM capacity market issues, to ensure that resource economics, and therefore retirement and new entry decision-making, are based on an accurate assessment of the reliability value of all resources and system needs. This includes resource accreditation, resource performance incentives, market power mitigation rules, possible market rules for forward procurement of clean resource attributes, and other enhancements to the capacity market (Critical Issue Fast Path process, Resource Adequacy Senior Task Force, Clean Attribute Procurement Senior Task Force).
- To identify the need for resource attributes such as operating flexibility to operate the system reliably with a high penetration of renewable resources, and define products and market rules to

[66] R4 Report FAQ #15 ("... The intent of the study was to provide a simple analysis that compared potential exits, entry and demand requirements to inform discussions..."). PJM's rather untransparent analysis underpinning the R4 Report can be contrasted to a state IRP process, under which stakeholders would have access through discovery to all underlying data, including proprietary information, and opportunities for cross-examination of utility witnesses; or to a FERC process such as the RPM Quadrennial Review, where the utility's filing is supported by testimony, intervenors also submit testimony, and FERC staff may issue deficiency notices to gain additional information; or even to PJM's usual process of presenting its analysis to stakeholders for their review and feedback before finalization, which was not done here.

[67] The issue charges, schedules, and meeting materials for all PJM stakeholder processes can be found here.

procure them (Operating Committee, Regulation Market Design Senior Task Force, Distributed Energy and Inverter Based Resource Subcommittee, among other stakeholder groups)[68]

- To move toward more proactive approaches to regional and inter-regional transmission planning that anticipate future needs and ensure the grid expands in a timely and efficient manner (Planning Committee, Interconnection Process Subcommittee, Transmission Expansion Advisory Committee).

While there are challenges associated with the transition in the resource mix, there are also viable solutions that PJM and stakeholders are already at work developing. And while this work continues, the PJM markets will continue to send price signals that coordinate the pace of retirements and new entry.

[68] A quite thorough list of the PJM stakeholder processes engaged with the transition in the resource mix and the need for enhancements to energy and ancillary services markets is found in PJM's October 18, 2022 report in response to questions posed by the Federal Energy Regulatory Commission in FERC docket no. AD21-10, *Modernizing Wholesale Electricity Market Design*, pp. 15-18.

About the Author

James F. Wilson is an economist and independent consultant doing business as Wilson Energy Economics. He has forty years of consulting experience in the electric power and natural gas industries. Many of his past assignments have focused on the economic and policy issues arising from the introduction of competition into these industries, including restructuring policies, market design, market analysis and market power. Mr. Wilson has been involved in electricity restructuring and wholesale market design for over twenty years in PJM, New England, Ontario, California, MISO, New York, Russia, and other regions. He has a B.A. from Oberlin College and M.S. in Engineering-Economic Systems from Stanford University.

With regard to resource adequacy planning and capacity market design, Mr. Wilson has been involved in these issues in PJM, New England, California, the Midwest, and other regions. With respect to PJM's RPM capacity construct, he has prepared numerous affidavits, reports, and analyses of RPM and RPM-related issues. He has also been involved in the stakeholder processes around PJM load forecasting and capacity requirements studies for many years. Additional information and Mr. Wilson's CV are available at www.wilsonenec.com.