BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-40:
PIOs' RFR of July Resource Adequacy Report

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

In re	)
Resource Adequacy Report	)
Evaluating the Reliability and Security	)
Of the United States Electric Grid	)
	)

Motion to Intervene and Request for Rehearing of
Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar

I. INTRODUCTION

Pursuant to section 313 of the Federal Power Act ("the Act"), 16 U.S.C. § 825*l*, Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar ("Public Interest Organizations") hereby move, to the extent necessary, to intervene and request rehearing of the Department of Energy's ("Department" or "DOE") "Resource Adequacy Report: Evaluating the Reliability and Security of the United States" ("RAR").[1] The Department issued the RAR in response to Executive Order 14,262 *Strengthening the Reliability and Security of the United States Electric Grid,* April 8, 2025 ("Grid EO"),[2] and claims that the RAR is a "uniform methodology to identify at-risk region(s) and guide reliability interventions" as directed by the Grid EO.[3] But the Department simultaneously disclaims the utility of the RAR to guide interventions uniformly, acknowledging on the very first page that the various "entities responsible for the maintenance and operation of the grid" have information "that could further enhance the robustness of reliability decisions" in their parts of the grid.[4]

The flaws in the RAR continue. The Department overstates assumptions about demand growth and likely retirements while understating likely new entry, building into the RAR an inherent bias toward a finding of inadequate resource adequacy. The Department also departs from best practices by using a

[1] July 7, 2025, https://www.energy.gov/sites/default/files/2025-07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf (attached as Ex. 1) (hereinafter, the "RAR").

[2] 90 Fed. Reg. 15521 (Apr. 8, 2025) (hereinafter "Grid EO").

[3] *Id.* at vi.

[4] *Id.* at i.

deterministic approach, which fails to account for necessary uncertainties and demonstrates that the RAR's findings should not be taken as conclusive or form the basis for further extraordinary actions. And on some critical aspects of the RAR analysis, the Department simply fails to explain its own methodology; while the Department describes two thresholds at which the RAR projects outages will occur, it fails to explain when it applies the standard threshold and when it applies the elevated one. These flaws render any reliance on the RAR to "guide reliability interventions" arbitrary and capricious.

While the Department acknowledges that the RAR is unsuitable to guide reliability interventions uniformly and provided no notice or opportunity to comment, the Department nevertheless does not clarify how it will use the RAR, creating confusion as to whether the RAR, in conjunction with the Grid EO, is intended to function as a final rule. Public Interest Organizations believe that the RAR should not be used as the basis for future action by the Department. We submit this request for rehearing in an abundance of caution, to the extent the Department later argues that any of these issues must have been raised in a request for rehearing within 30 days of the publication of the RAR, 16 U.S.C. § 825*l*. We also reserve our right to argue in later proceedings that 16 U.S.C. § 825*l* does not apply.

In sum, the RAR is a poorly crafted solution in search of a problem; there is no "energy emergency" and the regulatory bodies who actually possess authority to ensure resource adequacy are doing their jobs. Consequently, the RAR serves no useful purpose and should simply be withdrawn. By DOE's own admission, the RAR cannot reasonably be relied on to guide DOE interventions, nor, given the false premise and multiple mistaken assumptions, does it provide any value even as a purely informational report. On the contrary, it will only cause confusion for grid operators, energy providers, and members of the public. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

II. STATEMENT OF ISSUES

1. The Department intrudes on Federal Energy Regulatory Commission ("FERC" or "the Commission") and state authority. 16 U.S.C. §§ 824a(c),824o-1; 42 U.S.C. § 7113.
2. The RAR's findings, even if accurate, do not demonstrate any emergency allowing the Department to compel generation under the Federal Power Act. 16 U.S.C. § 824a(c); S. Rep. No. 74-621 (1935); 10 C.F.R. § 205.371; 10 C.F.R. § 205.375; 46 Fed. Reg. 39,985.

3. The RAR is analytically flawed and does not rely upon substantial evidence. 16 U.S.C. 824a(a); 16 U.S.C. § 824o(a)(3).
4. The Department cannot use the RAR as a "uniform methodology" without giving notice and taking public comment. 5 U.S.C. §§ 552, 553; 10 C.F.R. §§ 205.371; 205.373.
5. The Department cannot use the RAR as a "uniform methodology" without following National Environmental Policy Act procedural requirements. 42 U.S.C. § 4332(C).

III. INTERVENTION

Each of the Public Interest Organizations has interests that may be directly and substantially affected by the use of this RAR as a "uniform methodology" to guide "reliability interventions," including the issuance of Emergency Orders under Section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c).[5] To the extent that the RAR is determined to be an Order or Rule, each party may intervene in this proceeding.[6] And to the extent the Department treats the RAR as binding and uses it to guide reliability interventions, each of the Public Interest Organizations and their members will suffer concrete injuries that are redressable through rehearing.[7] Each organization is therefore aggrieved if the RAR is a "uniform methodology" for use in guiding interventions, as the Department purports, and each organization may properly apply for rehearing, assuming without conceding that the rehearing procedures apply.[8]

A. Natural Resources Defense Council

Natural Resources Defense Council ("NRDC") is a national non-profit membership organization whose mission includes ensuring the rights of all people to clean air, clean water, and healthy communities. NRDC has a longstanding organizational commitment to protect the interests of its members and to reducing pollution caused by fossil fuel fired power plants. NRDC works to achieve clean

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[5] *See* RAR, Ex. 1 at iv.

[6] *See* U.S. Dep't of Energy, DOE 202(c) Order Rehearing Procedures, https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures (last visited June 18, 2025) (archived version attached as Ex. 2) (hereinafter "DOE Rehearing Procedures"). This website was altered after June 18, 2025, and the procedures were removed. *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website. *See also* Email from Lot Cooke, U.S. Dep't of Energy to Linda Alle-Murphy Re: Rehearing procedures for DOE Order No. 202-05-3 (December 30, 2005) (recommending that "a party seeking rehearing can look for procedural guidance to [Federal Energy Regulatory Commission's ("FERC")] Rules of Practice and Procedure, 18 CFR Part 385.") (attached as Ex. 3).

[7] *See, e.g. Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346 (D.C. Cir. 2009).

[8] *See* 16 U.S.C. § 825*l*(a); *Wabash Valley Power Ass'n, Inc. v. FERC*, 268 F.3d 1105, 1112-13 (D.C. Cir. 2001); *NextEra Energy Res. v. ISO New Eng., Inc.*, 157 FERC ¶ 61,059, at P 5 (2016).

energy solutions that will lower consumer energy bills, meet greenhouse gas emission reduction goals, accelerate the use of energy efficiency and renewable energy, and ensure that clean energy is affordable and accessible to all. NRDC has hundreds of thousands of members across the United States. These NRDC members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject NRDC members to air and water pollution in the areas where they live, work, and recreate. NRDC members are also exposed to the noise and visual impacts of these facilities' operations. In addition, NRDC members are ratepayers in regions who will be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. For that reason, NRDC filed requests for rehearing of DOE's 202(c) orders issued to the J.H. Campbell and Eddystone plants, the latter of which explicitly stated that it would be reexamined following publication of the methodology. NRDC has five U.S. offices that also will be subject to higher electric bills as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." Moreover, NRDC has a sustainable operations plan with a goal of reducing net creation of greenhouse gas emissions derived from building operational activity to zero. NRDC and its members therefore have a strong interest in promoting actions that displace less cost-effective fossil generation with more cost-effective clean energy.

B. The Ecology Center

The Ecology Center is a Michigan-based non-profit organization headquartered in Ann Arbor, Michigan, with additional offices in Detroit, Michigan. Ecology Center is a public interest organization with more than 50 years of experience advocating for clean energy production, healthy communities, environmental justice, and a sustainable future. Ecology Center works at the local, state, and federal level. Its programs address systemic sources of poor health and environmental degradation through unique partnerships with environmental health and environmental advocates. Ecology Center has over 6,000 members and supporters, that live, use electricity, and pay electric bills in Michigan and could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. In addition, Ecology Center members are harmed by orders to operate fossil fuel powered generation past planned retirement dates because continued operation will subject Ecology Center members to air and water pollution in the areas where they live, work, and recreate.

C. Environmental Defense Fund

The Environmental Defense Fund ("EDF") is a non-profit membership organization with hundreds of thousands of members nationwide whose mission is to build a vital Earth for everyone by preserving the natural systems on which all life depends. Guided by expertise in science, economics, law, and business partnerships, EDF seeks practical and lasting solutions to address environmental problems and protect human health, including in particular by addressing pollution from the power sector. On behalf of its members, EDF works with partners across

the private and public sectors to engage in utility regulatory forums at the federal level and throughout the United States to advocate for policies that will create an affordable, reliable, and low pollution energy system. Recent 202(c) Orders issued by the DOE have harmed members of EDF by causing increases in pollution, which impact the health of people and nature, and in energy costs. EDF has submitted requests for rehearing regarding the DOE Orders related to the J.H. Campbell and Eddystone power plants and a Petition for Review regarding the DOE Order regarding the J.H. Campbell plant. Further 202(c) Orders issued as a result of the RAR, including extensions of the J.H. Campbell and Eddystone orders and orders directed at other generators, will result in further pollution and cost impacts that will harm EDF members.

D. Environmental Law and Policy Center

Environmental Law and Policy Center ("ELPC") is a not-for-profit environmental organization with members, contributors, and offices throughout the Midwest. Among other things, ELPC advocates before state public service commissions and the Federal Energy Regulatory Commission for clean, reliable energy generation in order to reduce ratepayer costs and improve environmental outcomes. ELPC members in the Midwest live, work, and recreate near power plants that burn coal or other fossil fuels and are directly impacted by their pollutants. In addition, ELPC members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. ELPC and its members could be subject to higher electric bills and impacted by additional pollution as a result of "reliability interventions" undertaken as a result of the RAR's "uniform methodology." ELPC has a longstanding organizational commitment to protect the interests of its members, to reduce pollution caused by fossil fuel-fired power plants, and to promote clean, reliable energy generation.

E. Public Citizen

Public Citizen, Inc. hereby intervenes in these proceedings. Public Citizen, Inc. is an active intervenor and participant before the Federal Energy Regulatory Commission in Federal Power Act proceedings, as well as before the U.S. Department of Energy in both electricity export and natural gas export dockets to ensure just and reasonable rates and that utilities' operations are consistent with the public interest. Established in 1971, Public Citizen, Inc. is a national, not-for-profit, non-partisan, research and advocacy organization representing the interests of American household consumers. Public Citizen has members in all 50 states and represents the interests of consumers, not represented by any other party in this proceeding. Financial details about our organization are on our website: www.citizen.org/about/annual-report/.

F. Sierra Club

Sierra Club is a national environmental non-profit whose purpose is to explore, enjoy, and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; to educate and enlist humanity to protect and restore the quality of the natural and human environment; and to use all lawful means to carry out these objectives. To those ends, the Sierra Club and its members have worked to limit pollution caused by fossil-fuel-fired power plants through public education and advocacy at the local, state, and federal level. Sierra Club represents over 640,000 members nationwide, many of whom reside and recreate in the regions in which the RAR purports to identify resource shortfalls requiring the continued operation of coal- and gas-fired generation. Sierra Club members in those areas would be harmed by the pollution and the increased utility rates caused by any such continued operation.

G. Vote Solar

Vote Solar is an independent 501(c)(3) non-profit working to re-power the U.S. with clean energy by making solar power more accessible and affordable through effective policy advocacy. In over half of the country, Vote Solar seeks to promote the development of solar at every scale, from distributed rooftop solar to large utility-scale plants. Vote Solar has over 90,000 members nationally. Vote Solar members are ratepayers in regions who could be subject to higher electric bills as a result of new or renewed 202(c) Orders issued as a result of the RAR. Vote Solar is not a trade organization, nor does it have corporate members. Vote Solar is committed to promoting clean, renewable energy and transitioning away from coal generation.

IV. BACKGROUND

A. Executive Orders

The genesis of the RAR lies in the President's unsupported day one declaration of a national energy emergency: *Declaring a National Energy Emergency* ("Energy Emergency EO").[9] That declaration's lack of factual underpinning was highlighted in a recent report by DOE's independent statistics and analysis arm, the Energy Information Administration ("EIA"). The EIA report highlights how U.S. energy production and exports are currently at an all-time high.[10] Nonetheless, the Energy Emergency EO was cited as a basis for the

[9] Exec. Order No. 14,156, 90 Fed. Reg. 8433 (January 20, 2025) (hereinafter "Energy Emergency EO") (attached as Ex. 4). *See* also RAR, Ex. 1 at vi (explaining that the Grid EO "builds on" the Energy Emergency EO).

[10] *See* U.S. EIA, *U.S. primary energy production, consumption, and exports increased in 2024* (June 20, 2025), https://www.eia.gov/todayinenergy/detail.php?id=65524.

President's follow-up grid-specific executive order, the Grid EO, that led to DOE's publication of the RAR.[11]

The Grid EO directed DOE to take three steps to address the President's assertion that there may be lack of grid reliability in the future, including: 1) to streamline the processes to issue orders pursuant to Federal Power Act Section 202(c);[12] 2) to develop a reserve margin assessment methodology and use it to identify at risk regions and critical energy resources within those regions and to publish that methodology within 90-days of the Grid EO;[13] and 3) to establish a protocol for identifying critical generating resources and taking action to prevent retirement or conversion of the fuel source of such resources.[14]

Notably, the Grid EO was issued in conjunction with a series of actions by President Trump and DOE designed explicitly to prop up the coal and gas industries, including: 1) Executive Order 14,261, *Reinvigorating America's Beautiful Clean Coal Industry,*[15] which seeks to restart coal leasing and expand coal mining on federal lands, in addition to making these processes easier by offering loans and streamlining permitting;[16] 2) a Presidential Proclamation entitled *Regulatory Relief for Certain Stationary Sources to Promote American Energy* that exempts coal plants from complying with the U.S. Environmental Protection Agency's updated Mercury and Air Toxics Standards;[17] and 3) Executive Order 14,260, *Protecting American Energy from State Overreach*,[18] which directs the U.S.

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[11] Nor does the Energy Emergency EO supply legal support for the Grid EO. Under the National Emergencies Act, 50 U.S.C. § 1631, a declaration of national emergency does not authorize the exercise of emergency powers "unless and until the President specifies the provisions of law under which he proposes that he, or other officers will act." But as Congress made clear, the statute "is not intended to enlarge or add to Executive power" such as authority under Section 202(c), only to "establish clear procedures and safeguards for the exercise by the President of emergency powers conferred on him by other statutes." S. Rep. No. 94-1168, 3 (1976).

[12] Grid EO Section 3(a).

[13] *Id.* Section 3(b).

[14] *Id.* Section 3(c).

[15] *See* Exec. Order No. 14,261, 90 Fed. Reg. 15,517 (Apr. 8, 2025).

[16] DOE simultaneously announced several initiatives to subsidize the coal industry, including loan guarantees for coal-fired power plant projects. Dep't of Energy, *Energy Department Acts to Unleash American Coal by Strengthening Coal Technology and Securing Critical Supply Chains* (Apr. 8, 2025), https://www.energy.gov/articles/energy-department-acts-unleash-american-coal-strengthening-coal-technology-and-securing.

[17] Proclamation No. 10914, 90 Fed. Reg. 16777 (Apr. 8, 2025).

[18] Exec. Order No. 14,260, 90 Fed. Reg. 15513 (Apr. 8, 2025).

Department of Justice to take action to block states' exercises of their police powers to protect their residents from pollution caused by coal and fossil-fuel sources.[19]

B. RAR

On July 7, 2025, DOE published the RAR on its website. The RAR includes a deterministic analysis of the resource adequacy of the current electric system and three 2030 cases: (1) the Plant Closure case includes 104 GW of coal and gas retirements plus 100% of NERC's Tier 1 additions; (2) the No Plant Closures case includes no retirements but 100% of NERC's Tier 1 additions; and (3) the Required Build case begins with the Plant Closures scenario and projects what additional added perfect capacity would be needed to meet the RAR's determined reliability standards.[20] Each of the three 2030 scenarios assume 50 GW of load growth from data centers and an additional 51 GW of load growth from other sources.[21] The Department finds in the RAR that, under the current system, only ERCOT fails to achieve DOE's selected resource adequacy targets,[22] but that, based on the methodology used to forecast the 2030 scenarios, there will be broader resource adequacy issues in 2030.[23] And, notwithstanding the RAR's upfront acknowledgement that the analysis used "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level,"[24] the Department proceeds to make broad declarations of future need based on its findings in the RAR.[25]

DOE explained that the RAR was being issued pursuant to the Grid EO. The RAR incorporates a full copy of the Grid EO and explains that "[t]his report serves as DOE's response to [the Grid EO's] Section 3(b) … by delivering the required uniform methodology to identify at-risk region(s) and guide reliability

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[19] These actions mimic President Trump's failed efforts to prop up the coal industry during his first term, including DOE's proposed rule, soundly rejected by FERC, that would have provided assured cost recovery (including a return on equity) for coal and nuclear plants (*see* 162 FERC ¶ 61,012), and the President's unfulfilled directive that DOE use Section 202(c) and the Defense Production Act to block closure of uneconomic coal plants while requiring grid operators to bear the costs. *See* Draft Memorandum (May 29, 2018), https://embed.documentcloud.org/documents/4491203-Grid-Memo/.

[20] RAR, Ex. 1 at 4-5.

[21] *Id.* at 2-3, 15-17.

[22] *Id.* at 7.

[23] *Id.* at 6-9.

[24] *Id.* at i.

[25] *Id.* at 1-2. *See also*, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security.

interventions."[26] DOE's statement that it intends to use the methodology "to guide reliability interventions" and that DOE will continue to use the RAR "on a regular basis to ensure its usefulness for effective action among industry and government decision-makers across the United States" suggests that the RAR may be intended to also serve as the protocol called for by Section 3(c) of the Grid EO.[27] But the RAR fails to clarify this, or, if the RAR does not also serve as DOE's response to Section 3(c), whether a protocol has been or will be developed, or whether any protocol will be made public. The RAR does not include any discussion of Section 3(a) of the Grid EO. To the extent that the Department addressed that portion of the Grid EO's directions, it has not made any process changes public. On the contrary, the Department has made its processes under Section 202(c) even less transparent by removing the existing process guidance from the DOE website.[28]

Notwithstanding the statement in the RAR that DOE intends to use the "methodology to identify at-risk region(s) and guide reliability interventions," e.g., Section 202(c) Orders,[29] other portions of the RAR make clear that it can't and shouldn't be used as a basis for interventions, specifically not issuance of 202(c) Orders. First and foremost, the reliability projections in the RAR focus on conditions five years from now and concede that there are not current grid conditions that fit within Section 202(c)'s definition of an "emergency." Second, the Department candidly concedes the RAR's lack of robustness: "DOE acknowledges that the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level. The DOE study team built the methodology and analysis upon the best data that was available. However, entities responsible for the maintenance and operation of the grid have access to a range of data and insights that could further enhance the robustness of reliability decisions, including resource adequacy, operational reliability, and resilience."[30]

C. Section 202(c) Orders

Section 202(c) of the Federal Power Act allows the Secretary of Energy, in certain emergency situations, to require by order temporary connections of facilities, and generation, delivery, interchange, or transmission of electricity as the Secretary

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[26] RAR, Ex. 1 at vi.

[27] *Id.*

[28] *Compare* https://web.archive.org/web/20250604093213/https://www.energy.gov/ceser/doe-202c-order-rehearing-procedures with the current website.

[29] *See* Dep't of Energy, *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security* (July 7, 2025), https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security ("The methodology also informs the potential use of DOE's emergency authority under Section 202(c) of the Federal Power Act.").

[30] RAR, Ex. 1 at i.

determines will best meet the emergency and serve the public interest. Section 202(c) has an important purpose: to mitigate electricity shortages caused by war, drought, and other emergencies. In granting DOE the authority that Section 202(c) provides, Congress considered the severe societal consequences of blackouts and determined that avoiding those consequences justified allowing DOE to act without notice and to require operations that override environmental laws. But Congress was also very careful to narrowly limit DOE's use of that authority, as the title of the provision makes clear, to "temporary" "emergency" situations.[31] And while the statute doesn't define "emergency," DOE's regulations include a lengthy definition which reinforces the key element in the statute: 202(c) orders are for situations that are sudden and unexpected, not for longer term grid management.[32]

1. DOE's Past Use of 202(c) Orders

The Department's application of Section 202(c) consistently confirms the urgency of the conditions necessary to invoke the provision and underscores the lack of authority for the planned implementation scheme described in the Grid EO and RAR.[33] The Department's predominant practice has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[34]

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[31] *See, e.g., Richmond Power & Light,* 574 F.2d at 617 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not at those in which supply is adequate but a means of fueling its production is in disfavor.").

[32] 10 C.F.R. § 205.371: "'Emergency,' as used herein, is defined as an unexpected inadequate supply of electric energy which may result from the unexpected outage or breakdown of facilities for the generation, transmission or distribution of electric power. Such events may be the result of weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent. An emergency also can result from a sudden increase in customer demand, an inability to obtain adequate amounts of the necessary fuels to generate electricity, or a regulatory action which prohibits the use of certain electric power supply facilities. Actions under this authority are envisioned as meeting a specific inadequate power supply situation. Extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations. In such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed. Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent. Where an electricity outage or service inadequacy qualifies for a section202(c) order, contractual difficulties alone will not be sufficient to preclude the issuance of an emergency order."

[33] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[34] *See, e.g.,* Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between December 23 and

The law also requires the Department to narrowly tailor the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, limit the order to "only [the] hours necessary to meet the emergency," be "consistent with any applicable Federal, State, or local environmental law or regulation," and to "minimize[] any adverse environmental impacts.[35] Up until recently, the Department has routinely followed these provisions of the law.[36]

2. DOE's Recent Misuse of Section 202(c)

Prior to issuance of the RAR but consistent with the direction in the Grid EO, DOE issued two Section 202(c) orders blocking the planned closures of two fossil-fuel fired generation resources that were unreliable, uneconomic, and at the end of their useful lives: the J.H. Campbell coal-fired plant in West Olive Michigan,[37] and units 3 and 4 of the Eddystone oil and gas fired plant in Eddystone, Pennsylvania.[38] The Eddystone 202(c) Order stated that "DOE plans to use this methodology [i.e., the RAR] to further evaluate Eddystone Units 3 and 4," thus raising questions about DOE's intentions as to the legal status and efficacy of the RAR.

Public Interest Organizations filed requests for rehearing for both the J.H. Campbell and Eddystone 202(c) Orders.[39] In both cases DOE failed to identify conditions that would qualify as "emergencies" for the purpose of issuance of Section 202(c) Orders. And both Section 202(c) Orders impose significant costs on ratepayers,[40] while increasing emissions of air pollutants and providing no

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December 26) (attached as Ex.5); Department of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires) (attached as Ex.6); *see also* Benjamin Rolsma, *The New Reliability Override*, 57 CONN. L. REV. 789, 803-4 (describing "sparing[]" use of Section 202(c) outside of wartime shortages during the twentieth century) (attached as Ex. 7).

[35] 16 U.S.C.§ 824a(c)(2).

[36] *See, e.g.,* Ex.5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex.6, Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

[37]Dep't of Energy Order No. 202-25-3 (May 23, 2025) (attached as Ex. 8).

[38]Dep't of Energy Order No. 202-25-4 (May 30, 2025) (hereinafter "Eddystone 202(c) Order") (attached as Ex. 9).

[39] Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-3 (June 18, 2025) (hereinafter "Campbell RFR") (attached as Ex.10);Mot. to Intervene and Request for Rh'g and Stay of Pub. Int. Orgs., DOE Ord. No. 202-25-4 (June 27, 2025) (hereinafter "Eddystone RFR") (attached as Ex.11).

meaningful corresponding reliability benefit.[41] The Department denied both of Public Interest Organization's requests for rehearing by operation of law.[42]

D. Existing Mechanisms Ensure Resource Adequacy

In the United States, how electricity is bought and sold varies by region. Electric utilities can be either traditionally regulated and operate as vertically integrated monopolies, or they can operate in deregulated, competitive markets where electric energy prices are set by the market. Both vertically integrated utilities and utilities in deregulated markets are subject to federal oversight, and in some of the deregulated states, the state nonetheless exercises oversight over the terms of retail supply offers, especially for retail customers. And all utilities are subject to reliability standards developed by the North American Electric Reliability Corporation ("NERC") and approved by FERC. In sum, FERC, Regional Transmission Organizations ("RTOs"), States, and NERC all play a hand in ensuring resource adequacy.

1. Vertically integrated utilities

Until the 1990s, utilities were generally vertically integrated such that generation, transmission, and distribution resources were all held by the same entity.[43] Vertically integrated utilities must seek state approval for power plant investments.[44] Many state regulators require utilities to demonstrate the necessity of proposed investments through an integrated resource planning process.[45] This process is used for long-term planning and requires the utility to justify its investments and demonstrate how it plans to meet customer electricity demand.[46] Even though vertically integrated utilities generate their own electricity, many

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[40] *See e.g.* U.S. Sec. and Exch. Comm'n, Form 10-Q, Consumers Energy Company Quarterly Report For the Quarterly Period Ended June 30, 2025, at 39, 62, 92 (2025) https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/10a900b7-263b-4ccd-82a0-4162ba7ae5f2.pdf (describing costs of $29 million to operate Campbell through June 30, 2025); FERC Docket No. ER25-2653-000 (PJM proposed cost allocation to implement DOE Order 202-25-4).

[41] *See* Campbell RFR, Ex. 10 at 11-14; Eddystone RFR, Ex. 11 at 56-60. 87-88.

[42] Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-3A (July 28, 2025) (attached as Ex. 12); Dep't of Energy, Notice of Denial of Reh'g by Operation of Law and Providing for Further Consideration of Ord. No. 202-25-4A (Aug. 1, 2025) (attached as Ex. 13).

[43] *See* Kathryne Cleary and Karen Palmer, *US Electricity Markets 101* (March 17, 2022), Resources for the Future, https://www.rff.org/publications/explainers/us-electricity-markets-101/.

[44] *Id.*

[45] *Id.*

[46] *Id.*

trade with other utilities during times of need. These wholesale market transactions are subject to regulation by FERC.[47]

2. Competitive markets

Advances in technology and statutory changes led to the development of energy markets and merchant generation that is not owned by incumbent utilities.[48] In the 1990s, FERC fostered competitive markets through rules that allowed the establishment of independently-operated voluntary RTOs that determine the prices for energy, capacity, and ancillary services based on procurement and dispatch of least-cost resources through Order Nos. 888, 890, and 2000.[49] As RTO markets expanded, many states deregulated their utility monopolies and required them to join RTOs. Deregulated states use markets to determine which power plants are necessary for electricity generation.[50] Even in deregulated states, the state sites new generation. Market price signals encourage new investment when supply is tight and encourage the retirement of facilities that are no longer competitive when capacity is plentiful. RTOs now account for approximately 2/3 of all electricity sales in the U.S. and have saved consumers billions of dollars, increased reliability, and reduced environmental harm.[51]

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[47] *See* FERC, *Electric Power Markets* (last updated March 27, 2025), https://www.ferc.gov/electric-power-markets.

[48] *See, e.g.,* Order Terminating Rulemaking Proceeding, Initiating New Proceeding, And Establishing Additional Procedures, 162 FERC ¶ 61,012, PP 7-11 (2018); Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,639-31,645 (1996), order on reh'g, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. *New York v. FERC*, 535 U.S. 1 (2002).

[49] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 638-41 (1996), Order No. 890, FERC Stats. & Regs. ¶ 31,241, at 124-352 (1997), Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 99-130 (1999).

[50] State regulators in competitive markets still practice oversight over utilities. For example, some states, such as Michigan, use both the market and integrated resource planning. *See* Michigan Public Service Commission, *Phase III – Integrated Resource Plan* (last visited Aug. 4, 2025), https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid/phase-iii-integrated-resource-plan-mirpp-filing-requirements-demand-response-study-energy-waste-red. Other state legislatures or commissions have enacted subsidies to keep nuclear plants alive, such as in New York, Illinois, Ohio, and New Jersey. *See* U.S. EIA, Five states have implemented programs to assist nuclear power plants (Oct. 7, 2019), https://www.eia.gov/todayinenergy/detail.php?id=41534.

[51] *See, e.g.*, Judy Chang et al., The Brattle Group, Potential Benefits of a Regional Wholesale Power Market to North Carolina's Electricity Customers, 1, 3-7 (April 2019) https://www.brattle.com/wp-content/uploads/2021/05/16092_nc_wholesale_power_market_whitepaper_april_2019_final.pdf (discussing billions of dollars in estimated cost saving); Jennifer Chen & Devin Hartman, *Why wholesale market benefits are not always apparent in customer bills*, R Street (Nov. 10, 2021), https://www.rstreet.org/commentary/why-wholesale-market-benefits-are-not-always-apparent-in-

As explained by FERC, its "support of competitive wholesale electricity markets has been grounded in the substantial and well-documented economic benefits that these markets provide to consumers."[52] In addition to billions of dollars of consumer savings, FERC found that competitive markets protect consumers by "providing more supply options, encouraging new entry and innovation, spurring deployment of new technologies, promoting demand response and energy efficiency, improving operating performance, exerting downward pressure on costs, and shifting risk away from consumers."[53]

3. FERC and NERC Reliability Regulation

As part of its role in regulating the wholesale electric industry, FERC has implemented Congressional mandates to ensure system reliability, including establishing NERC as the Electric Reliability Organization, which sets industry standards for grid reliability that are approved by FERC;[54] coordination requirements for the natural gas and electricity market scheduling;[55] investigation and improvements required in light of the grid's response to extreme weather events;[56] and reviewing capacity accreditation processes to ensure that capacity markets generate reliable results.[57]

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customer-bills/ (same); Jeff St. John, *A Western US energy market would boost clean energy. Will it happen?*, Canary Media (Jun. 10, 2024), https://www.canarymedia.com/articles/utilities/a-western-us-energy-market-would-boost-clean-energy.-will-it-happen; John Tsoukalis et al., Assessment of Potential Market Reforms for South Carolina's Electricity Sector, at 6, 46, 77-78 (Apr. 27, 2019), https://www.scstatehouse.gov/CommitteeInfo/ElectricityMarketReformMeasuresStudyCommittee/2022-04-27%20-%20SC%20Electricity%20Market%20Reform_Brattle%20Report.pdf (discussing cost savings across regional wholesale markets).

[52] Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures, 162 FERC ¶ 61,012, P 11 (2018).

[53] *Id.* (citation omitted).

[54] PJM, NERC and Reliability Fact Sheet (Jan. 5, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/nerc-and-reliability-fact-sheet.pdf. *See also* PJM, PJM Ensures a Reliable Grid (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/reliability-fact-sheet.pdf.

[55] PJM, PJM Promotes Gas/Electricity Industry Coordination (Jan. 29, 2025), https://www.pjm.com/-/media/DotCom/about-pjm/newsroom/fact-sheets/gas-electric-coordination-fact-sheet.pdf. *See also* Order 787, 145 FERC ¶ 61,134 (2013); Order 809, 151 FERC ¶ 61,049 (2015).

[56] *See e.g.,* Centralized Capacity Markets in Regional Transmission Organizations and Independent System Operators, 149 FERC ¶ 61,145 (2014) (order addressing technical conferences on, among other things, the 2014 Polar Vortex); Order Approving Extreme Cold Weather Reliability Standards EOP-011-3 and EOP-012-1 and Directing Modification of Reliability Standard EOP-012-1, 182 FERC ¶ 61094 (2023); Order Approving Extreme Cold Weather Reliability Standard EOP-012-2 and Directing Modification, 187 FERC ¶ 61,204 (2024). *See also* FERC, NERC and Regional Staff, Inquiry into Bulk-Power System Operations During December 2022 Winter Storm Elliott (Oct. 2023), https://www.ferc.gov/sites/default/files/2023-11/24_Winter-Storm_Elliot_1107_1300.pdf; FERC, NERC and Regional Entity Joint Staff, The February 2021 Cold Weather Outages in Texas and the

V. ARGUMENT

A. The Department Is Intruding on FERC and State Authority.

The Department's authority over reliability is strictly circumscribed to respond to imminent emergencies;[58] this authority does not extend to regulating long-term or overarching aspects of the electricity sector. Rather, Congress reserved to the states and FERC the authority to regulate the electric sector generally and to regulate resource adequacy and reliability specifically. Recent actions—starting with the Energy Emergency EO and culminating in the RAR—indicate, however, that DOE is not remaining in its designated lane.[59] The RAR lays bare the Department's agenda to prop up fossil fuel businesses by utilizing emergency authority in a systematic fashion that goes well beyond the scope of DOE's authority under the Federal Power Act and illegally intrudes upon authorities that Congress has explicitly reserved to the states or given to FERC.

The authority to maintain a reliable electric system in the United States has evolved over the years to include parties at the federal, regional, state, and local levels.[60] But the Department of Energy has never been granted primary regulatory authority over either reliability or resource adequacy of the grid. Rather, the Department of Energy Organization Act of 1977 ("Organization Act")[61] and the

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South Central United States (Nov. 2021), https://www.nerc.com/pa/Stand/Project202107ExtremeColdWeatherDL/FERC%20Presentation-Phase%202.pdf; PJM, Winter Storm Elliott Event Analysis and Recommendation Report (2023), https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[57] *Id.*; *see also* Order Accepting Tariff Revisions Subject to Condition, 186 FERC ¶ 61,080 (2024).

[58] *See* 16 U.S.C. §§ 824a(c),824o-1.

[59] *See* Energy Emergency EO, Ex. 4; Grid EO Sec. 3 (RAR, Ex. 1 at C); RAR Ex. 1; DOE, DOE Fact Sheet, https://www.energy.gov/sites/default/files/2025-07/DOE_Fact_Sheet_Grid_Report_July_2025.pdf; DOE Press Release, https://www.energy.gov/articles/department-energy-releases-report-evaluating-us-grid-reliability-and-security; Eddystone 202(c) Order, Ex. 9; Dep't of Energy Order No. 202-25-3 (May 23, 2025), Ex. 8.

[60] *New York v. FERC*, 535 U.S. 1, 5-8 (2002) ("Prior to 1935, the States possessed broad authority to regulate public utilities"). *See generally* Nat'l Ass'n of Reg. Util. Comm'rs ("NARUC"), *Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms* (Nov. 2023) https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3?_gl=1*oyp366*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzEkdDE3NTM5ODk1NzUkajI1JGwwJGgw; NARUC, *Resource Adequacy Primer for State Regulators* (July 2021), https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[61] 42 U.S.C. § 7111 *et seq.*

Federal Power Act[62] give to the Department only narrow, emergency authority over the electric system—for example through Federal Power Act Sections 202(c) and 215A.[63] The President's declaration of an energy emergency (even if it were legitimate) and other executive orders cannot expand these statutorily defined authorities.[64] And while the Department may of course analyze policy implications and issue reports on various topics—as it has done since its founding—DOE's statements indicate that the RAR is not simply a policy analysis. The Department states—without limitation—that it will use the RAR "to identify at-risk region(s) and guide reliability interventions."[65] Thus, taking DOE at its word, the RAR is beyond the Department's authority.

Further, to the extent that it is an indication of the Department's broader scheme, in the RAR, the Department ignores the limitations on its authority and the comparative breadth of authority explicitly reserved to the states and FERC over the Department. "States are responsible for resource adequacy in siting of electric facilities, establishing retail electric rates, and overseeing the reliability of the distribution system."[66] State public utility commissions review utility proposals for long-term impacts to the system's reliability. "Most states address resource adequacy by requiring large investor-owned utilities to file long-term planning documents like integrated resource plans that include strategies for reliably meeting future demand."[67]

The structure and language of the Organization Act and Federal Power Act reflect Congress's deliberate choices to preserve this traditional state authority over generating facilities and to circumscribe the Department's emergency authority in light of the states' role. Congress noted in the Organization Act that "[n]othing in this chapter shall affect the authority of any State over matters exclusively within its jurisdiction."[68] And the first sentence of the Federal Power Act declares that

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[62] Subsequent legislation has also amended and updated these authorities. *See e.g.* Fixing America's Surface Transportation Act (FAST Act), Pub. L. No. 114–94, 129 Stat. 1312 (2015); Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).

[63] 16 U.S.C. §§ 824a(c), 824o-1.

[64] *See Biden v. Nebraska*, 600 U.S. 477, 500-01 (2023); *see also* S. Rep. No. 94-1168, 3 (1976), (the National Emergencies Act "is not intended to enlarge or add to Executive power. Rather, the statute is an effort by Congress to establish clear procedures and safeguards for the exercise by the President of emergency powers *conferred on him by other statutes*.") (emphasis added).

[65] RAR, Ex. 1 at vi.

[66] NARUC, *Resource Adequacy Primer for State Regulators*, at 9 (July 2021) https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042?_gl=1*1mituzu*_ga*MTc1NzM0NTE0LjE3NTM5ODk1NDA.*_ga_QLH1N3Q1NF*czE3NTM5ODk1NDAkbzEkZzAkdDE3NTM5ODk1NDAkajYwJGwwJGgw.

[67] Nat'l Renewable Energy Lab'y, *Explained: Fundamentals of Power Grid Reliability and Clean Electricity*, at 4 (Jan. 2024) https://docs.nrel.gov/docs/fy24osti/85880.pdf.

[68] 42 U.S.C. § 7113.

federal regulation extends "only to those matters which are not subject to regulation by the States."[69] Section 201(b)(1) further states that, except as otherwise "specifically" provided, federal jurisdiction does not attach to "facilities used for the generation of electric energy."[70] The courts have held that Section 201(b)(1) reserves to the states authority over electric generating facilities,[71] including the authority to order their closure.[72] Congress also recognized the states' exclusive authority over generating facilities in Section 202(b), which provides that FERC's interconnection authority does not include the power to "compel the enlargement of generating facilities for such purposes."[73] And when Congress added new authority regarding reliability to the Federal Power Act in 2005, it also still explicitly clarified that "[n]othing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard…."[74]

The RAR also intrudes upon authority that Congress explicitly and repeatedly gave exclusively to FERC, not the Department. In 1935, Congress passed the Federal Power Act, creating the Federal Power Commission to engage in "federal regulation of electricity in areas beyond the reach of state power."[75] However, until the 1970s, the federal government played a very limited role in energy policy and generally left to private industry and state and local governments the task of establishing energy policies and planning.[76] In 1977, Congress passed the Organization Act,[77] creating both the Department and FERC. The Organization Act transferred most of the authority for overseeing the electric system in the

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[69] 16 U.S.C. § 824(a).

[70] *Id.* § 824(b)(1).

[71] *See, e.g., Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 154 (2016).

[72] *Conn. Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (2009) (under Section 201(b), states retain the right "to require retirement of existing generators" or to "take any other action in their role as regulators of generation facilities."). *See also Devon Power LLC et al.*, 109 FERC ¶ 61,154, P 47 (2004) ("Resource adequacy is a matter that has traditionally rested with the states, and it should continue to rest there. States have traditionally designated the entities that are responsible for procuring adequate capacity to serve loads within their respective jurisdictions.").

[73] 16 U.S.C. § 824a(b).

[74] 16 U.S.C. § 824o.

[75] *New York v. FERC*, 535 U.S. 1, 6 (2002).

[76] DOE, *A Brief History of the Department of Energy,* https://www.energy.gov/lm/brief-history-department-energy. *See also* DOE, *Department of Energy 1977-1994, A Summary History* (Nov. 1994), https://www.energy.gov/sites/prod/files/2017/09/f36/DOE%201977-1994%20A%20Summary%20History_0.pdf.

[77] Public Law 95–91 (1977), 42 U.S.C. § 7101 *et seq.*

Federal Power Act to FERC, not the Department;[78] the Department retained primary authority only over "emergency interconnection."[79]

While FERC is housed within the Department, FERC is an independent agency with distinct authority from the Department that the Department may not modify or supersede.[80] Generally the Department "is authorized to establish, alter, consolidate or discontinue such organizational units or components within the Department as [the Secretary] may deem to be necessary or appropriate."[81] But this authority explicitly does not extend to FERC. The Organization Act explains that the Department may not abolish "organizational units or components established by" the Organization Act, nor may it "transfer [] functions vested by this chapter in any organizational unit or component."[82] Because the Organization Act created[83] and transferred specific authority to FERC,[84] the Department has no authority to alter FERC itself nor to seize FERC's statutorily prescribed authority.

Further, "the decision of the Commission involving any function within its jurisdiction . . . shall be final agency action . . . and *shall not be subject to further review by the Secretary* or any officer or employee of the Department."[85] While the Department can propose rules under FERC's jurisdiction, FERC maintains "exclusive jurisdiction . . . to take final action on any proposal made by the Secretary."[86] And when the Department proposes a rule in the exercise of its own functions that FERC determines significantly affects any function within FERC's jurisdiction, FERC can insist on changes that DOE must adopt if DOE wants to issue the rule.[87]

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[78] 42 U.S.C. § 7172 (transferring functions from Federal Power Commission to FERC); 42 U.S.C. § 7151 (the function of the Federal Power Commission is transferred to the Secretary except as provided to FERC). The Department and FERC share authority over certain parts of the Federal Power Act that primarily address recordkeeping and administration. 42 U.S.C. § 7172(a)(2) ("The Commission may exercise any power under the following sections to the extent the Commission determines such power to be necessary to the exercise of any function within the jurisdiction of the Commission: (A) sections 4, 301, 302, 306 through 309, and 312 through 316 of the Federal Power Act.").

[79] *See* 42 U.S.C. § 7172(a)(1)(B).

[80] *See* 42 U.S.C.A. § 7112 (Congressional declaration of purpose in establishing Department); 42 U.S.C. § 7171 (establishment of FERC).

[81] 42 U.S.C. § 7253.

[82] 42 U.S.C. § 7253.

[83] 42 U.S.C. § 7171 (establishment of FERC).

[84] 42 U.S.C. § 7172(a) (transferring functions from Federal Power Commission to FERC).

[85] 42 U.S.C. § 7172(g) (emphasis added).

[86] 42 U.S.C. § 7173. *See* 162 FERC ¶ 61,012.

[87] 42 U.S.C. § 7174.

In 2005, Congress expanded FERC's authority to specifically encompass reliability by updating the Federal Power Act in the 2005 Energy Policy Act.[88] While "FERC had previously addressed electric grid reliability in an indirect manner, such as allowing the cost recovery of public utility expenditures that address discrete reliability matters,"[89] there had been no mandatory reliability standards adopted by any federal regulator. When providing recommendations on reliability in 1998, the Department had concluded "that the U.S. Congress should explicitly assign oversight of bulk-power reliability to the FERC."[90] The new Section 215 followed the Department's suggestion and "tasked FERC [—not the Department—] with a direct role over an entire new field of activity."[91] Section 215 authorizes FERC to certify an electric reliability organization; FERC designated NERC. It is therefore NERC that develops reliability standards that FERC reviews to ensure consistency with federal law.[92] The broad reliability authority Congress granted to FERC contrasts with the very narrow, emergency authority in Section 215A that Congress granted to the Department.[93] The RAR appears to duplicate FERC and NERC's reliability efforts, impermissibly intruding upon authority Congress chose to give FERC —subject to elaborate procedural and substantive limitations—not the Department.

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[88] Pub. L. No. 109-58, 119 Stat. 594 (2005).

[89] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[90] DOE, *Maintaining Reliability in a Competitive U.S. Electricity Industry* at vii-viii, xiv (Sept. 29, 1998), https://certs.lbl.gov/sites/all/files/basic-page/maintainting-reliability-in-competitive-electricity-industry-1998_0.pdf ("The Administration has proposed legislation that would provide the federal oversight necessary to make reliability standards mandatory. The NERC has begun to reinvent itself to respond to the changing needs of the industry. In addition, the FERC has undertaken several reliability initiatives. However, much more is needed. The Congress, for example, urgently needs to clarify the FERC's authority over an electric industry self-regulating reliability organization and expand the FERC's jurisdiction for reliability over the bulk-power system.") ("The Task Force is confident that the electricity industry, overseen by the Federal Energy Regulatory Commission (FERC) and a restructured self-regulating reliability organization (such as the planned North American Electric Reliability Organization [NAERO]), can and will maintain today's high levels of reliability."). *See also* S. Rep. No. 106-324, Electric Reliability 2000 Act (proposals from Congress such as this one gave FERC the authority over reliability).

[91] FERC, *Reliability Primer*, at 5 (2020) https://www.ferc.gov/sites/default/files/2020-04/reliability-primer_1.pdf.

[92] FERC, Reliability Explainer (Aug. 16, 2023) https://www.ferc.gov/reliability-explainer#:~:text=Both%20NERC%20and%20FERC%20have,blackouts%20or%20systematic%20compliance%20failures.

[93] The 2015 amendment to Federal Power Act creating Section 215A (16 U.S.C. 824o-1(d)) gives DOE the authority to issue orders to address emergencies related to malicious acts resulting from physical attacks to the grid at limited 15-day increments.

Finally, the Department arbitrarily and capriciously assumes that the existing systems are not working. The states and FERC have—pursuant to their authority—established systems to maintain resource adequacy and reliability including integrated resource planning processes and capacity markets. These existing systems are designed to signal to build more energy generation when energy demand rises.[94] Recently, as the Department notes in the RAR, energy demand has been rising; but the Department fails to acknowledge that the state and FERC systems already are appropriately responding, negating claims of an emergency or the need for the Department to interfere, as discussed *infra* in Section C.[95] For example, PJM's, SPP's, and MISO's new "fast track" processes—adopted to address concerns of resource adequacy—"alone would add roughly twice what the DOE assumed for the entire nation."[96] The RAR is written arbitrarily and capriciously incorporating the implicit assumption that capacity market results are not reliable, and that market-driven generator retirement is cause for alarm.

In sum, Congress has explicitly reserved to the states and FERC primary regulatory authority over resource adequacy and reliability. The Department's only authority to directly regulate reliability of the electric grid is narrow emergency authority such as Federal Power Act Sections 202(c) and 215A. The Department does not have broader authority to interfere with resource adequacy or reliability regulations. To the extent that the RAR is the confirmation of the attempt to usurp that authority from the states and FERC, via a "uniform methodology" in the RAR, it is outside of DOE's statutory authority and contrary to law.

B. The Department's Findings in the RAR, Even if Accurate, Do Not Demonstrate Any Emergency Allowing the Department to Compel Generation Under the Federal Power Act.

Even if the findings in the RAR were accurate (which they are not, as explained in Section C below), they would not empower the Department to exercise any statutory authority, under "section 202 of the Federal Power Act" or otherwise, to override state- or market-driven changes to the electricity generating facilities supplying the grid.[97] As discussed in Section A above, the Federal Power Act gives the Department tightly circumscribed authority over resource adequacy planning, to address "emergency" conditions through "such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" as

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[94] *See e.g.* DOE, A Primer on Electric Utilities, Deregulation, and Restructuring of U.S. Energy Markets, at 3.8 (May 2002); GridLab, GridLab Analysis: Department of Energy Resource Adequacy Report, at 4 (July 11, 2025) (hereinafter "GridLab Analysis") (attached as Ex. 14).

[95] GridLab Analysis, Ex. 14 at 2-3.

[96] GridLab Analysis, Ex. 14 at 3.

[97] Grid EO at Sec. 3 (RAR, Ex. 1 at C-3).

"will best meet the emergency and serve the public interest."[98] The statutory text, structure, and history, as well as case law interpreting Section 202(c), the Department's regulations, and its historic use of Section 202(c), all establish that its "emergency" authority is confined to sudden, unexpected, imminent, and specific electricity shortfalls. The information in the RAR, at most, expresses the Department's view that bulk-power system reliability will be insufficient in 2030. The Department's conclusions in the RAR—even if assumed to be accurate for the sake of argument—consequently provide no basis for the Department to manipulate the electricity market.

1. The Federal Power Act only permits the Department to intervene when necessary to address an imminent, unexpected, and specific electricity shortfall.

The Federal Power Act's text, context, and structure, as well as caselaw and the Department's longstanding regulations, all establish that it does not permit the Department to "prevent" generating facilities "from leaving the bulk-power system" or "converting" from one fuel-source to another based on the Department's view of long-term reliability needs.[99] The Act provides the Department only authority to intervene in electricity markets when necessary to address imminent, near-term, and exigent electricity supply shortfalls requiring immediate response, through the cabined authority provided by Section 202(c) of the Act.

a. The Text of Section 202(c) Narrowly Limits the Department's Authority to Emergencies: Imminent, Unexpected, and Certain Shortfalls in Electricity Supply.

The Act's text empowers the Department to require generation only in an "emergency;"[100] the Act primarily reserves authority over generation to the states, allocating more limited federal regulatory power to different agencies, *see section* A above. The statute itself does not define "emergency." At the time Congress enacted Section 202(c), Webster's New International Dictionary of the English Language (1930) defined "emergency" as a "*sudden* or *unexpected* appearance or occurrence . . . An *unforeseen* occurrence or combination of circumstances which calls for *immediate* action or remedy; *pressing* necessity; exigency."[101] Contemporary dictionaries similarly define "emergency" as demanding imminence: an emergency

[98] 16 U.S.C. 824a(c).

[99] Grid EO at Sec. 3(c)(ii) (RAR, Ex. 1 at C-4).

[100] 16 U.S.C. § 824a(c).

[101] Emphasis added.

is "an *unforeseen* combination of circumstances or the resulting state that calls for *immediate* action."[102]

The remainder of Section 202(c) underscores the exigency inherent in the governing term "emergency." The authority granted by Section 202(c) is, in the first instance, a war-time power.[103] An "emergency" under the statute is limited to circumstances of similar urgency: "a *sudden* increase in the demand for electric energy," for example.[104]

The text's use of the present tense also underscores that focus on imminent and certain shortfalls: it empowers the Department to act only where "an emergency *exists*."[105] That near-term focus along with the statute's strictly "temporary" authority[106] precludes use of Section 202(c) to pursue long-term policy goals, such as "fear of overdependence" on foreign oil supplies,[107] or "energy independence."[108]

Section 202's overall structure further highlights Section 202(c)'s emphasis on imminent, near-term concerns. The preceding subsections 202(a) and (b) together define and limit the tools by which the federal government may pursue "abundant" energy supplies in the normal course.[109] The resulting statutory "machinery for the

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[102] Merriam Webster's Dictionary 407 (11th ed. 2009) (emphasis added); *see* 3 Oxford English Dictionary 119 (1st ed. 1913) (defining emergency similarly as "a state of things *unexpectedly* arising, and urgently demanding *immediate* action" (emphasis added)); *see also* Rolsma, Ex. 7 at 812 n.147 (noting that dictionaries have given the term "emergency" the "same meaning for many years").

[103] 16 U.S.C. § 824a(c) (beginning with "[d]uring the continuance of any war in which the United States is engaged"); *see Jarecki v. G.D. Searle & Co.*, 367 U.S. 303, 307 (1961) (noting that statutory terms should be interpreted in the context of nearby parallel terms "in order to avoid the giving of unintended breadth to the Acts of Congress").

[104] 16 U.S.C. § 824a(c) (emphasis added); *see Richmond Power & Light,* 574 F.2d at 615 (holding that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances"); S. Rep. No. 74-621, at 49 (1935) (explaining that Section 202(c) provides "temporary power designed to avoid a repetition of the conditions during the last war, when a serious power shortage arose").

[105] 16 U.S.C. § 824a(c) (emphasis added).

[106] 16 U.S.C. § 824a(c).

[107] *Richmond Power & Light*, 574 F.2d at 617.

[108] RAR, Ex. 1 at 1. *See Richmond Power & Light*, 574 F.2d at 614 (Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances, and is aimed at situations in which demand for electricity exceeds supply and not those in which supply is adequate but a means of fueling its production is in disfavor.").

[109] 16 U.S.C. § 824a(a) (seeking "abundant supply of electric energy" by directing the federal government to "divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy") & 824a(b)

promotion of the coordination of electric facilities" comprises the following: in subsection (a), an instruction to establish a general framework meant to facilitate "coordination by voluntary action;" in subsection (b), "limited authority to compel interstate utilities to connect their lines and sell or exchange energy," subject to defined procedural and substantive requirements, when "interconnection cannot be secured by voluntary action;" and in subsection (c), "much broader" but "temporary" authority "to compel the connection of facilities and the generation, delivery, or interchange of energy during times of war or other emergency."[110]

That tiered structure—relying on voluntary action for quotidian energy planning, specifying limited authority where that voluntary system fails, and allowing for "temporary" central command-and-control only in case of "emergency"—requires that Section 202(c) remain narrowly bounded to instances of an immediate and unavoidable "break-down in electric supply,"[111] rather than mere want of more abundant supply in the future.[112] Interpreting Section 202(c)'s "emergency" powers to encompass longer-term concerns—e.g., potential shortfalls years into the future, or an expected "expansion of artificial intelligence data centers and an increase in domestic manufacturing,"[113]—would unwind the careful balance of voluntary, market-driven action and federal power set out in subsections 202(a) and 202(b). Such an interpretation cannot be squared with the statutory text and structure.[114]

b. Congress' Enactment of a Specific, Cabined Scheme to Address Reliability Concerns Confirms that Section 202(c) Cannot be Expanded to Impose Requirements Related to Long-Term Reliability.

That the Department's Section 202 powers may not be used to enforce the Department's view of long-term reliability needs is confirmed by Section 215 of the Federal Power Act—which specifically and directly delineates the scope of federal power to enforce mandatory long-term reliability requirements for the bulk-power system.[115] Congress added Section 215 to the Federal Power Act in 2005 precisely because the Act as it then existed—including Section 202—did not provide the

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(allowing federal government to order "physical connection … to sell energy or to exchange energy" upon application, and after an opportunity for hearing).

[110] S. Rep. No. 74-621 at 49 (1935).

[111] *Id.*

[112] *cf.* Eddystone 202(c) Order, Ex. 9 at 2 (imposing responsibility on PJM "to ensure maximum reliability on its system").

[113] Grid EO at Sec. 1 (RAR, Ex. 1 at C-4).

[114] *See Otter Tail Power Co. v. Fed. Power Comm.*, 429 F.2d 232, 233-34 (1970) (holding that Section 202(c) "enables the Commission to react to a war or national disaster," while Section 202(b) "applies to a crisis which is likely to develop in the foreseeable future").

[115] 16 U.S.C. § 824o.

federal government with the power to enforce measures designed to ensure broad, long-term reliability.[116]

By enacting Section 215, Congress provided a comprehensive and carefully circumscribed scheme to empower the federal government to enforce long-term reliability requirements. That statutory scheme strikes a careful balance between state and federal authority, and between private, market-driven decisions and top-down control. Reliability standards are devised by NERC independent "of the users and operators of the bulk-power system" but with "fair stakeholder representation."[117] FERC may approve or remand those standards (but not replace them with its own) and is required to "give due weight" to NERC's "technical expertise" while independently assessing effects on "competition."[118] Section 215 provides specified enforcement mechanisms and procedures for reliability standards—which mechanisms conspicuously exclude the power to command specific generation resources to remain operational.[119] And Section 215 carefully preserves state authority over "the construction of additional generation" and in-state resource adequacy, establishing regional advisory boards to ensure appropriate state input on the administration of reliability standards.[120]

Interpreting Section 202(c) to permit the Department to mandate generation based on its own unfettered assessment of long-term bulk-system reliability would effectively allow the Department to bypass Section 215's procedural safeguards, constraints on federal authority, and protection of state power. Such a bypass would impermissibly "contradict Congress' clear intent as expressed in its more recent," reliability-specific "legislation," enacted "with the clear understanding" that the Department had "no authority" to address long-term reliability through Section

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[116] *See* 70 Fed. Reg. 53,118 ("In 2001, President Bush proposed making electric Reliability Standards mandatory and enforceable," leading to enactment of Section 215 in 2005); RAR of the National Energy Policy Development Group (May 2001) at p. 7-6, https://www.nrc.gov/docs/ml0428/ml042800056.pdf (noting that "[r]egional shortages of generating capacity and transmission constraints combine to reduce the overall reliability of electric supply in the country" and that "one factor limiting reliability is the lack of enforceable reliability standards" because "the reliability of the U.S. transmission grid has depended entirely on *voluntary* compliance," and then recommending "legislation providing for enforcement" of reliability standards (emphasis added)); S. Rep. No. 109-78 at 48 (2005) (Section 215 "changes our current voluntary rules system" for long-term reliability "to a mandatory rules system."). *See Alcoa, Inc. v. FERC*, 564 F.3d 1342, 1344 (D.C. Cir. 2009) (noting that prior to the Energy Policy Act of 2005, "the reliability of the nation's bulk-power system depended on participants' voluntary compliance with industry standards").

[117] 16 U.S.C. § 824o(c)-(d). *See also id.* 824o(a)(3) (defining reliability standards as "a requirement … to provide for reliable operation of the bulk-power system").

[118] *Id.* § 824o(d)(2)-(4).

[119] *Id.* § 824o(e).

[120] *Id.* § 824o(i)-(j).

202(c).[121] Congress has, in Section 215, directly established the mechanisms (and limitations) by which the federal government may compel action to ensure long-term electric-system reliability. In so doing, it has confirmed that the Department may not, through Section 202(c) "emergency" orders, use long-term reliability concerns to mandate the generation it views as required to address long-term reliability needs.

c. DOE's Regulations Similarly Establish that Section 202(c) Emergency Authority Can Only Be Invoked to Address Imminent, Certain Supply Shortfalls Requiring Immediate Response.

The Department's regulations demonstrate its own long-standing understanding that Section 202(c)'s authority is confined to imminent and unavoidable resource shortages, rather than a mechanism to address long-term concerns as to the reliability of the bulk-power system. The regulations define an emergency as "an *unexpected* inadequate supply of electric energy which may result from the *unexpected* outage or breakdown" of generating or transmission facilities—not a means of planning against distant expectations or risks.[122] Emergencies "may result" from a number of events.[123] The use of the verb "result," defined as "arise as a consequence, effect, or conclusion," suggests that the event triggering the emergency has already happened rather than that there is a speculation that it could occur.[124]

Moreover, the events are characterized by those produced by "weather conditions, acts of God, or unforeseen occurrences not reasonably within the power of the affected 'entity' to prevent."[125] Where the culprit is increased demand, it must be "a *sudden* increase in customer demand" producing a "*specific* inadequate power supply situation,"[126] rather than long-term demand projections producing general reliability concerns. The need for both specificity and certainty is repeated in the Department's regulations defining an inadequate energy supply: "A system may be considered to have" inadequate supply when "the projected energy deficiency . . . *will* cause the applicant [for a 202(c) Order] to be unable to meet its

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[121] *See FDA v. Brown & Williamson Tobacco Corp.*, 529 U.S. 120, 142 & 149 (2000); s*ee also Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 401–02 (D.C. Cir. 2004) ("Congress's specific and limited enumeration of [agency] power" over a particular matter in one section of the Federal Power Act "is strong evidence that [a separate section] confers no such authority on [agency].").

[122] 10 C.F.R. § 205.371 (emphasis added).

[123] *Id.* ("may result from the unexpected outage," "may be the result of weather conditions," "can result from a sudden increase in customer demand").

[124] Merriam-Webster's Collegiate Dictionary (11th ed. 2003) 1063.

[125] 10 C.F.R. § 205.371

[126] *Id.* (emphasis added).

normal peak load requirements based upon use of all of its otherwise available resources so that it *is* unable to supply adequate electric service to its customers."[127]

And while the regulations suggest that "inadequate planning or the failure to construct necessary facilities *can result* in an emergency," they recognize that the Department may not utilize a "continuing emergency order" to mandate long-term system planning.[128] An emergency may exist where past planning failures produce an immediate, present-tense shortfall (that is where, a shortfall *results* from insufficient planning); the Department has no authority to commandeer bulk-system reliability planning merely because it deems current plans inadequate to meet far-distant needs.[129] As the Department stated when it promulgated those regulations, the statute allows the Department to provide "assistance [to a utility] during a period of unexpected inadequate supply of electricity," but does not empower it to "solve long-term problems."[130]

d. Courts Have Uniformly Held that Section 202(c) Can Be Invoked Only in Immediate Crises.

Two courts have addressed the scope of authority under Section 202(c), and both determined that this Section applies only when there is a sudden, unexpected, imminent, and specific emergency.

Richmond Power and Light of City of Richmond, Indiana v. FERC, 574 F.2d 610 (D.C. Cir. 1978), arose out of the 1973 oil embargo. The Federal Power Commission needed to decide how to respond to oil shortages, and decided to call for the voluntary transfer for electricity from non-oil power plants to areas of the country that relied heavily on oil, such as New England.[131] The New England Power Pool was not convinced that the voluntary program would work and petitioned the Commission for a 202(c) order.[132] The Commission instead facilitated an agreement between state commissions and supplying utilities, which satisfied the New England Power Pool and it withdrew its petition.[133] A dissatisfied utility

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[127] 10 C.F.R. § 205.375 (emphasis added).

[128] 10 C.F.R. § 205.371 (also recognizing that "where a shortage of electricity is projected due solely to the failure of parties to agree to terms, conditions, or other economic factors" there is no emergency "unless the inability to supply electric service is *imminent*" (emphasis added)).

[129] *See* 10 C.F.R. § 205.375 (requiring present inability to meet demand to demonstrate inadequate energy supply).

[130] 46 Fed. Reg. at 39,985–86.

[131] 574 F.2d at 613.

[132] *Id.*

[133] *Id.*

sought judicial review of the Commission's decision to allow the withdrawal of the Section 202(c) petition.[134]

The court easily upheld the Commission's decision not to invoke Section 202(c).[135] Though the oil embargo had ended, the utility argued that the "high cost and uncertain supply of imported oil" justified an emergency order.[136] The Commission countered that the voluntary program had worked, the New England Power Pool never interrupted service, there was no need for a Section 202(c) order, and the court agreed.[137]

Trying another tactic, the utility argued that "dependence on imported oil leaves this country with a *continuing* emergency."[138] The court observed that Section 202(c) "speaks of 'temporary' emergencies, epitomized by wartime disturbances."[139] Interpreting this statutory language, the court upheld the Department's view that Section 202(c) cannot be used when "supply is adequate but a means of fueling its production is in disfavor."[140] Section 202(c) is not an appropriate means to implement long-term national policy to switch fuels. It is only a temporary fix for a temporary problem.

The Eighth Circuit has similarly held that Section 202(c) can only be used to respond to immediate crises. In *Otter Tail Power Co. v. Federal Power Commission*, 429 F.2d 232 (8th Cir. 1970), a utility insisted that the only way for the Federal Power Commission to properly order the utility to connect to a municipal power provider was to issue a Section 202(c) order. Demand for electricity in the city had increased, and the peak load of the municipal power provider was getting to be so high that both of its two generators would likely need to be used simultaneously in the near future, "causing a possible loss of service should one malfunction during a peak period."[141] To avoid this possible loss of service, the Federal Power Commission issued a Section 202(b) order, requiring the utility to connect the municipal power provider. The utility argued that the Federal Power Commission used the wrong section and should have used Section 202(c) instead.

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[134] *Id.* at 614.

[135] *Id.*

[136] *Id.*

[137] *Id.* at 615.

[138] *Id.* (emphasis added).

[139] *Id.*

[140] *Id.*

[141] *Id.* at 233-34.

The court explained that Section 202(c) "enables the Commission to react to a war or national disaster" by ordering "immediate" interconnection during an "emergency."[142] For non-emergency situations, "[o]n the other hand, Section 202(b) applies," including when there is a "crisis which is likely to develop in the foreseeable future but which does not necessitate immediate action on the part of the Commission."[143] The court upheld the Commission's use of Section 202(b) instead of Section 202(c) because there was no immediate emergency.

The case law uniformly supports the interpretation that Section 202(c) can only be used in acute, short-term, urgent emergencies.

e. The Department's Prior Orders Recognize that Section 202(c) Does Not Confer Plenary Authority Over Long-Term Resource Adequacy.

The Department's past applications of Section 202(c) corroborate the urgency of the emergency conditions that are the necessary predicate for any Department intervention under that section.[144] The Department's predominant practice outside of wartime has been to use Section 202(c) to address specific, imminent, and unexpected shortages—not to address longer-term reliability concerns or demand forecasts.[145] The Department has also narrowly tailored the remedies in Section 202(c) orders to ensure that the orders only address the stated emergency, to limit the order to the minimum period necessary, and to mitigate violations of environmental requirements and impacts to the environment.[146]

Public Interest Organizations are not aware of any instance in which the Department has utilized Section 202(c) to mandate generation the Department

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[142] *Id.* at 234 (citing 16 U.S.C. § 824a(c)).

[143] *Id.*

[144] *See FTC v. Bunte Brothers, Inc.*, 312 U.S. 349, 352 (1941) ("[J]ust as established practice may shed light on the extent of power conveyed by general statutory language, so the want of assertion of power by those who presumably would be alert to exercise it, is equally significant in determining whether such power was actually conferred.").

[145] *See, e.g.,* Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) (responding to ongoing severe winter storm producing immediate and "unusually high peak load" between Christmas Eve and Boxing Day); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 10-2 (responding to shortages produced by ongoing extreme heat and wildfires); *see also* Ex.7 Rolsma, 57 Conn. L. Rev. at 803-4 (describing "sparing[]" use of Section 202(c) outside of war-time shortages during the twentieth century).

[146] *See, e.g.*, Ex. 5, Dep't of Energy Order No. 202-22-4 (Dec. 24, 2022) at 4-7 (limiting order to the 3 days of peak load, directing PJM to exhaust all available resources beforehand, requiring detailed environmental reporting, notice to affected communities, and calculation of net revenue associated with actions violating environmental laws); Ex. 6 Dep't of Energy Order 202-20-2 (Sept. 6, 2020) at 3-4 (limiting order to the 7 days of peak load, directing CAISO to exhaust all available resources beforehand, requiring detailed environmental reporting).

views as necessary to ensure long-term resource sufficiency—and for good reason.[147] Any such use would exceed the Department's statutory authority.

2. In the RAR, DOE purports to identify only long-term, uncertain, and generalized concerns with bulk-power system reliability, which do not enable the Department to compel generation pursuant to Section 202(c).

Given the statutory limitations described above, the RAR provides no basis for the Department to use Section 202(c) to require that particular "generation resources" are "retained as an available generation resource," or to "prevent . . . an identified generation resource . . . from leaving the bulk-power system or converting" its fuel source.[148] Nor does the Department identify any other source of legal authority for DOE to impose such requirements. In the RAR, the Department only purports to identify capacity shortages that might affect bulk-system reliability in 2030.[149] The Department acknowledges that all but one region—ERCOT—currently meet its criteria.[150] Its claim that shortages might arise five years from now, even if it were correct—would present no "emergency" under Section 202(c). Those non-imminent resource needs are, rather, precisely the long-term reliability and resource adequacy matters over which Congress allocated responsibility to FERC and NERC.

Second, the Department identifies only a "risk of power outages" even in 2030[151] based on the Department's projected "AI and data center load growth under the given assumptions for generator build outs by 2030, generator retirements by 2030, reserve requirements, and potential load growth."[152] The Department acknowledges, meanwhile that its analysis "is not an indication that reliability coordinators would allow this level of load growth to jeopardize the reliability of the system."[153] The RAR—even by its own terms—thus does not specify any shortfall that is certain enough to justify invocation of the Department's emergency powers under Section 202(c). Its numbers are, rather, "indicators to determine where it may be beneficial to encourage increased generation and transmission capacity to meet an expected need."[154] Section 202(c) does not authorize the Department to order generation based on such non-certain shortfalls; it provides distinct, and

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[147] *See Richmond Power and Light,* 574 F.2d at 616.

[148] Grid EO at 2.

[149] *E.g.,* RAR, Ex. 1 at 1, 20, 27, 30, 32, 40.

[150] RAR, Ex. 1 at 7.

[151] *Id.* at 1.

[152] *Id.* at 7.

[153] *Id.*

[154] *Id.*

much more limited powers, by which the Department may facilitate "an abundant supply of electric energy throughout the United States."[155]

And third, the Department does not claim to identify any particular location in which a shortfall might occur, or the specific resources that might best serve to address such shortfall. Instead, in the RAR, the Department provides aggregate estimates of potential loss-of-load under "varied grid conditions and operating scenarios based on historical data."[156] But those estimates do not demonstrate that any single generating facility would best meet the resulting shortfall, and could not therefore justify an emergency order directing a facility to remain available.

Consequently—even setting aside methodological flaws—the Department asserts resource risks in the RAR that are neither imminent, certain, nor specific. Those risks do not describe an emergency that would permit the Department to intervene pursuant to Section 202(c). They represent, rather, the Department's view as to measures that might "assur[e] an abundant supply of electric energy throughout the United States."[157] Section 202 does not permit the Department to compel generation on that basis. The Department also describes in the RAR the measures the Department believes "necessary to provide for reliable operation of the bulk-power system."[158] But Section 215 gives FERC, not the Department, the power to provide for reliable operation of the bulk power system, and specifies the procedures by which such measures must be developed and enforced; the Federal Power Act does not permit the Department to end-run those limitations by deeming long-term reliability an emergency. The RAR consequently could not form the basis of any action by the Department to compel generation under Section 202 of the Federal Power Act.

C. The RAR Is Analytically Flawed and Does not Rely Upon Substantial Evidence.

The RAR is severely flawed and does not meet DOE's own information quality standards. There are significant informational and methodological limitations and clear analytical and data errors. Any reliance on the RAR to "guide interventions" or to serve as a basis for any DOE decisionmaking would be arbitrary and capricious and not based on substantial evidence, in violation of the Administrative Procedure Act.

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[155] 16 U.S.C. § 824a(a).

[156] RAR, Ex. 1 at 2. *See, e.g., id.* at 21.

[157] 16 U.S.C. § 824a(a).

[158] 16 U.S.C. § 824o(a)(3).

1. The RAR falls woefully short of informational and methodological best practices.

DOE admits the RAR was hastily thrown together without sufficient information. At the outset, DOE acknowledges the resource adequacy analysis in the RAR "could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[159] Indeed, "[h]istorically, the nation's power system planners would have shared electric reliability information with DOE through mechanisms such as EIA-411, which has been discontinued."[160] DOE continues to explain that a key takeaway of the RAR is the need for "strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our collective economic and national security."[161] The candor in these comments is revealing; these limitations prove that the RAR does not meet the requirements of the Information Quality Act ("IQA") or DOE's guidelines thereunder.[162] The RAR should be withdrawn so that the Department does not continue to disseminate this poor-quality information, and the RAR should not be relied on in any decisionmaking. In the alternative, the Department should not use the RAR as support for any final action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) explains in detail the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before releasing a final version that incorporates and responds to public comment.

The IQA directs agencies to "ensur[e] and maximiz[e] the quality, objectivity, and integrity of information (including statistical information) disseminated by Federal Agencies."[163] Office of Management and Budget ("OMB") guidelines issued

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[159] RAR, Ex. 1 at i.

[160] *Id.*

[161] *Id.*

[162] *See* Pub. L. 106-554 Sec. 515, 114 Stat. 2763A-153.

[163] *Id.* OMB's government-wide information quality guidelines direct agencies to issue their own implementing guidelines. Agencies must provide the public a way to administratively seek and obtain correction of information disseminated by the agency that does not comply with OMB or agency guidelines. *See* Office of Management and Budget, Guidelines for Ensuring and Maximizing the Quality, Objectivity, Utility, and Integrity of Information, 67 Fed. Reg 8452 (Feb. 22, 2002); Office of Management and Budget, Memorandum for the Heads of Executive Departments and Agencies (Apr. 24, 2019) (hereinafter "OMB Guidelines 2019 Update"), https://www.whitehouse.gov/wp-content/uploads/2019/04/M-19-15.pdf.

Pursuant to the OMB directive, DOE has issued its own agency-specific information quality guidelines. *See* Dep't of Energy, Final Report Implementing Office of Management and Budget Information Dissemination Quality Guidelines (Oct. 1, 2002), no. 6450-01-p, https://www.energy.gov/sites/prod/files/cioprod/documents/finalinfoqualityguidelines03072011.pdf; Dep't of Energy, Final Report Implementing Updates to the Department of Energy's Information

pursuant to the IQA require agencies to ensure that scientific information including "factual inputs, data, models, analyses . . . related to such disciplines as . . . engineering, or physical sciences" undergo certain review procedures to maintain quality standards.[164]

To that end, agencies must "choose a peer review mechanism that is adequate, giving due consideration to the novelty and complexity of the science to be reviewed, the relevance of the information to decisionmaking, the extent of prior peer reviews, and the expected benefits and costs of additional review."[165] Agencies must "strive to ensure that their peer review practices are characterized by both scientific integrity and process integrity," including the "rationale and supportability" of the agency's findings and ensuring "avoidance of real or perceived conflicts of interest" and "a workable process for public comment and involvement."[166] Agencies are encouraged to "have the choice of input data and the specification of the model reviewed by peers before the agency invests time and resources in implementing the model and interpreting the results," in order to "focus attention on data inadequacies in time for corrections . . . before the agency becomes invested in a specific approach."[167] Additionally, peer reviewers must "ensure that scientific uncertainties are clearly identified and characterized," and "ensure that the potential implications of the uncertainties for the technical conclusions drawn are clear."[168] OMB IQA guidelines also require agencies to evaluate "the sensitivity of the agency's conclusions to analytic assumptions."[169] These steps of peer review determine a report's "fitness . . . for policy purposes."[170]

DOE IQA guidelines further note that "in disseminating certain types of information to the public, other information must also be disseminated in order to ensure an accurate, clear, complete, and unbiased presentation."[171] Agencies should provide open access to data and modeling information underlying a report.[172]

Quality Act Guidelines (2019) (hereinafter "DOE IQA Guidelines 2019 Update"), available at https://www.energy.gov/cio/articles/2019-final-updated-version-doe-information-quality-guidelines.

[164] OMB, Final Information Quality Bulletin for Peer Review, 70 Fed. Reg. 2664, 2667 (Jan. 14, 2005); *see also* OMB Guidelines 2019 Update at 4.

[165] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg. at 2668.

[166] *Id.*

[167] *Id.*

[168] *Id.* at 2669.

[169] OMB Guidelines 2019 Update at 4.

[170] *Id.*

[171] DOE IQA Guidelines 2019 Update at 16.

[172] OMB Guidelines 2019 Update at 8; *See also*, e.g., *Chem. Mfrs. Ass'n v. U.S. EPA*, 870 F.2d 177, 200 (5th Cir. 1989) ("fairness requires that the agency afford interested parties an opportunity to challenge the underlying factual data relied on by the agency."); *United States v. Nova Scotia Food*

Additionally, DOE is "responsible for ensuring that the information [being disseminated in a report] is consistent with the OMB and DOE guidelines and that the information is of adequate quality for dissemination."[173] For reports containing "influential financial, scientific, or statistical information," DOE must "identify for the [Chief Information Officer] a high ranking official" who is responsible for higher level review of the report's conclusions.[174]

OMB's IQA guidelines recognized that the "[f]ederal government's assessment of risk can directly or indirectly influence the response actions of state and local agencies or international bodies."[175] Thus, under the OMB and DOE guidelines, influential information—information routinely embargoed because of "potential effect on markets" or information "on which a regulatory action with a $100 million per year impact is based"—must meet the highest standards of quality and transparency, and should undergo the rigorous review procedures outlined above.[176]

Here, the RAR does not comply with IQA requirements, rendering any further reliance on it to be arbitrary and capricious. For example, the RAR appears to be inconsistent with internal review processes required: it should have undergone peer review because of its "influential" nature, particularly if the RAR is, as it purports to be, a "uniform methodology" to guide reliability interventions, such as Federal Power Act Section 202(c) orders, which have outsize economic impacts. However, there is no evidence that the RAR underwent any peer review, and, given the time constraints, it is unlikely it did. The Department further failed to make available all underlying data and modeling information used to create the RAR. Additionally, as described in detail below, the RAR relies on improper analytic assumptions, including overstated demand and understated supply forecasts. The RAR includes faulty analysis based on these improper assumptions despite DOE's acknowledgment of significant informational limitations regarding regional- and utility-level engineering data. In addition, the RAR contains numerous errors, such as referring to appendices that do not exist or incorrect appendices,[177] stating

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Prods. Corp., 568 F.2d 240, 251-53 (2d Cir. 1977) (holding that regulation was promulgated in arbitrary and capricious manner where agency failed to disclose data on which it relied).

[173] DOE IQA Guidelines 2019 Update at 22.

[174] *Id.* at 22-23.

[175] OMB Information Quality Bulletin for Peer Review, 70 Fed. Reg at 2667.

[176] DOE IQA Guidelines 2019 Update at 7.

[177] *See* RAR, Ex. 1, at 12 (referring to nonexistent "Outputs" section of an unnamed appendix); *id.* (referring to Appendix B for further detail regarding retirement assumptions, whereas Appendix B describes Canadian transfer limits).

inaccurate units for generation capacity,[178] and falsely asserting bulk power system load shedding occurred in regions during certain events.[179]

2. In the RAR, the Department overstates assumptions about demand.

In the RAR, the Department assumes 101 GW of load growth by 2030—a 15% increase over 2025 load. This increase is more than double the high case in the U.S. EIA 2025 Annual Energy Outlook, which forecasts 6% growth.[180] This extraordinarily high assumed load growth contributes substantially to the findings of low resource adequacy under the Plant Closures scenario in the RAR. As explained below, in the RAR, the Department omits consideration of many factors that will likely dampen load growth in the coming 5 years, thus undermining the validity and usefulness of its results.

The Department assumes 50 GW of load growth from data centers by 2030, which it characterizes as the midpoint among other available forecasts.[181] However, it does not appear that DOE's forecast accounts for load flexibility at these data centers, which would significantly reduce the overall demand that these centers place upon the grid during the periods of peak system risk. While certain data centers may not be capable of load curtailment due to their purpose, many can be flexible. Even a small amount of data center load flexibility provides significant benefits. A recent study by experts at Duke University found that curtailment at data centers during only 0.25% of the year would enable 76 GW of data center power demand to be added to the system today, without triggering resource adequacy problems or requiring further expansion.[182] The White House recently issued an AI Action Plan endorsing demand flexibility as a means to maintain resource adequacy as data center capacity expands: "the United States should investigate new and novel ways for large power consumers to manage their power consumption during critical grid periods to enhance reliability and unlock additional power on the system."[183]

The Electric Power Research Institute has begun an initiative to enhance data center flexibility in light of its benefits for grid reliability, under which

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[178] *Id.* at 9 (text stating that PJM has a shortfall of 2.4 MW).

[179] *See infra* subsection C.6.

[180] *See* GridLab Analysis, Ex. 14 at 2.

[181] RAR, Ex. 1 at 2.

[182] Norris, T. H., T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell. 2025. Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems at 20. Durham, NC: Nicholas Institute for Energy, Environment & Sustainability, Duke University, https://nicholasinstitute.duke.edu/publications/rethinking-load-growth (attached as Ex. 15).

[183] White House, Winning the Race: America's AI Action Plan 15 (July 2025), https://www.whitehouse.gov/wp-content/uploads/2025/07/Americas-AI-Action-Plan.pdf.

demonstration projects were set to deploy in the first half of 2025.[184] Early results from other projects to test data center flexibility have been promising.[185] Evaluations of the RAR by GridLab and the NYU Institute for Policy Integrity ("IPI") both have concluded that the Department's failure to account for data center load flexibility renders its findings of elevated reliability risk in 2030 suspect.[186] This is particularly true for DOE's findings concerning the ERCOT region, considering that in June 2025, Texas enacted a law allowing curtailment of these loads during grid emergencies.[187]

Furthermore, it is unclear whether the RAR's data center load forecasts account for potential constraints on the growth of data centers, such as shortages of critical semiconductor chips,[188] and other grid equipment like transformers and switchgears.[189] In addition to the Texas policy mentioned above, states and utilities are proposing new tariff designs for data centers to ensure that data centers don't

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[184] Elec. Power Rsch. Inst., EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027.").

[185] *See* Anuja Ratnayake, Unlocking AI Potential with Data Center Flexibility, ENERGYCENTRAL (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-aipotential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance.").

[186] NYU Institute for Policy Integrity, *Enough Energy*, at 25 (attached as Ex. 16) (hereinafter "IPI Report"); *see also* GridLab Analysis, Ex. 14 at 2 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

[187] S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis, UTILITY DIVE (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

[188] *See, e.g.* London Economics International LLC, *Uncertainty and Upward Bias Are Inherent in Data Center Electricity Demand Projections* at 39 (July 7, 2025) (attached as Ex. 17), https://www.selc.org/wp-content/uploads/2025/07/LEI-Data-Center-Final-Report-07072025-2.pdf.

[189] How big tech plans to feed AI's voracious appetite for power, The Economist (July 28, 2025), https://www.economist.com/business/2025/07/28/how-big-tech-plans-to-feed-ais-voracious-appetite-for-power.

pose risks to the distribution system or shift costs to other consumers, all of which could slow or redirect the forecasted data center load growth.[190] The Department fails to evaluate any of these dynamics in the RAR.

In addition to the overall rate of data center load growth, the Department also uses a poorly described and supported methodology to allocate data center load to different regions. As the IPI observes, DOE used state-level growth ratios to allocate the projected data center load across regions, "[b]ut it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load)."[191] IPI posits that "some computing demand may be served from other regions if it will be cheaper to integrate the data center elsewhere," and observes that "[g]iven the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets."[192] Figure 8 in the RAR (New Data Center Build) shows that DOE's estimates for the percentage of data center load growth that will be built in various RTOs in some cases differs substantially from the percentages in the various forecasts that DOE used to calculate its overall data center load growth estimate. DOE does not explain why it discards these studies' more geographically specific estimates and instead relies on a single state-level growth ratio derived from a different study.

The Department's approach to estimating non-data center load growth by 2030 is also poorly explained in the RAR and likely flawed. DOE relies upon NERC's 2024 Long-Term Reliability Assessment forecast for overall load growth, but because the Department otherwise seeks to include elevated levels of data center load growth in the RAR, it must back out an estimate of data center load growth from the overall forecast.[193] The estimate that DOE chooses to back out is a "low-growth" case for data center load from a different source (which DOE presents in volumetric consumption terms, rather than peak demand). This approach, without further information to understand DOE's analysis, could have resulted in DOE over-estimating non-data center load growth. This effect is likely exacerbated by recent changes in federal law that will reduce electricity consumption from

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[190] Jason Plautz, *Rulemakers play catch-up as data centers multiply*, E&ENews by Politico (July 18, 2025), https://www.eenews.net/articles/rulemakers-play-catch-up-as-data-centers-multiply/.

[191] IPI Report, Ex. 16 at 26.

[192] *Id.*

[193] RAR, Ex. 1 at 17 ("Given the rapid emergence of AI/DC loads, additional steps were taken to account for this category of demand. It is difficult to determine how much AI/DC load is already embedded in NERC [Long-Term Reliability Assessment] forecast, for example, the 2024 [Long-Term Reliability Assessment] saw more than 50GW increase from 2023, signaling a major shift in utility expectations. To benchmark existing AI/DC contribution, DOE assumed base 2023 AI/DC load equaled the EPRI low-growth case of 166 TWh.").

specific sectors, including vehicles and hydrogen electrolysis. The utility forecasts included in the NERC Long-Term Reliability Assessment included projections of vehicle and building electrification that depend in part on tax credits and incentives that were revoked prior to publication of the RAR as part of the One Big Beautiful Bill Act ("OBBBA"). Recent analysis shows that the elimination or reduction of tax credits that supported new sources of electricity load growth will have a meaningful effect by 2030.[194] As a result, DOE's non-data center load growth projections are likely overstated.

3. Assumptions about supply are unsupported.

a. In the RAR, the Department Overstates Likely Retirements.

The Department finds the most dire resource adequacy shortfalls occur in the Plant Closures case, in which it assumes 104 GW of retirements by 2030.[195] This estimate is much higher than the most recent data from the EIA released in June 2025 in its authoritative Form 860, which shows 50 GW fewer retirements than assumed in the RAR.[196] As GridLab experts explained, DOE assumed not only "these 50 GW of likely retirements, but [also] included another 50 GW of *announced* retirements."[197] While it may be appropriate to include announced retirements in certain long-term planning exercises, it is unreasonable to assume such retirements will happen as the basis for extraordinary emergency actions. Without more detail about any formal or binding characteristics of those announcements, or the factors purportedly driving those announcements, it is impossible to verify the validity of this input that doubles the amount of otherwise projected resource retirements. Even EIA's Annual Energy Outlook, which does model projected retirements beyond those already formally noticed, finds 10 GW fewer thermal retirements by 2030 than does DOE.[198] Without further support for the 50 GW assumed retirement

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[194] *See, e.g.,* Princeton NetZero Lab and Evolved Energy Research, A Fork in The Road: Impacts of Federal Policy Repeal on the U.S. Energy Transition, at Tab 12 (last updated July 3, 2025), https://public.tableau.com/app/profile/evolvedenergyresearch/viz/AForkinTheRoad_ImpactsofFederalPolicyRepealontheU_S_EnergyTransition_June/1Title (showing approximately 100 TWh annual energy use reduction in 2030 compared to mid-range estimates of the status quo ante).

[195] RAR, Ex. 1 at 5.

[196] U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0. *See also* GridLab Analysis, Ex. 14 at 2.

[197] GridLab Analysis, Ex. 14 at 2; *see also* IPI Report, Ex. 16 at 24 (explaining that DOE's "number includes both 'confirmed' retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and 'announced' retirements—which are publicly stated but not officially noticed.").

[198] According to the U.S. EIA's 2025 Annual Energy Outlook, coal-fired generating capacity is projected to decline by 93.6 GW between 2025 and 2030 in the Reference case, approximately 10

value, the Plant Closures case is nothing more than speculation about what might happen if certain assumptions were to come true.

Such assumptions are particularly unjustified given that, as GridLab notes, "[m]ost likely many plants will choose not to retire due to the changing regulatory and economic landscape."[199] The IPI makes a similar point in their critique of DOE's retirement assumptions, noting that "the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources."[200] As one snapshot of this trend, high capacity prices in the PJM region led to 1.1 GW of resources withdrawing formal deactivation notices since last summer.[201] IPI also observes that the Trump Administration is seeking to rescind or reexamine many federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire before 2030, "which could cause resources to delay their retirements."[202]

b. In the RAR, the Department Understates Likely New Entry by 2030 and Other Sources of Supply.

Among the most impactful and unsupported assumptions in the RAR is that "only [generation] projects that are very mature in the pipeline (such as those with a signed interconnection agreement) will be built" by 2030.[203] DOE thus constrains its analysis to include only projects designated as Tier 1 in the NERC 2024 Long Term Resource Assessment, which it then maps to Interregional Transfer Capability Study regions. Because Tier 1 includes only resources that are already under construction, have signed construction service agreements, and similar

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fewer GW of retirements than modeled in the DOE report. No other fossil fuel technology shows a net decrease in generating capacity in the 2025 Annual Energy Outlook analysis. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[199] GridLab Analysis, Ex. 14 at 2.

[200] IPI Report, Ex. 16 at 24.

[201] PJM Inside Lines, PJM Auction Procures 134,311 MW of Generation Resources; Supply Responds to Price Signal (July 22, 2025) https://insidelines.pjm.com/pjm-auction-procures-134311-mw-of-generation-resources-supply-responds-to-price-signal/ ("Since the 2025/2026 Base Residual Auction results were posted on July 30, 2024, 17 generating units totaling approximately 1,100 MW worth of Capacity Interconnection Rights have withdrawn their retirements").

[202] IPI Report, Ex. 16 at 24-25.

[203] RAR, Ex. 1 at 12.

characteristics,[204] this assumption "results in minimal capacity additions beyond 2026."[205] As experts at GridLab observe, the assumption that "no projects are built post 2026, [] is not realistic for a report forecasting to 2030."[206] This is especially true given rising energy prices due to increased demand, which is attracting more investment to the market and driving new construction of generation resources.

The Department also states in the RAR that of these Tier 1 additions, just 22 GWs of generator additions are "firm" (thermal) resources, which severely underestimates new gas generation compared to other projections. According to GridLab, "a more reasonable assumption for forecasted capacity additions is the EIA 860 released in June 2025, which has 35 GW of gas additions, and another 53 GW of batteries [for a total of] 88 GW of firm additions by 2030."[207] Other federal government projections are even higher: EIA's 2025 Annual Energy Outlook projects 90 GWs of new fossil generators added to the system through 2030.[208] 80 GWs of the EIA-projected natural gas growth are in earlier development stages and likely did not meet the 2024 NERC Long-Term Reliability Assessment Tier 1 criteria to be included in the RAR.

As researchers at the IPI conclude, DOE departed from best practice in declining to include any resources classified by NERC as "Tier 2" resources[209] in the overall resource adequacy analysis for 2030, even those at advanced stages of the interconnection process.[210] A reasonable process could have involved "examin[ing]

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[204] *See* IPI Report, Ex. 16 at n.155 (citing NERC, 2024 Long Term Reliability Assessment, 137 (last updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf).

[205] RAR, Ex. 1 at A-5.

[206] GridLab Analysis, Ex. 14 at 3.

[207] *Id.*

[208] According to the U.S. EIA, the policy-neutral reference case projects a 93.29 GW increase in combined cycle, fossil steam, and combustion turbine capacity between 2025 and 2030. U.S. EIA, Annual Energy Outlook 2025: Table 9. Electricity generating capacity (March 2025), https://www.eia.gov/outlooks/aeo/data/browser/#/?id=9-AEO2025&region=0-0&cases=ref2025&start=2025&end=2030&f=A&linechart=ref2025-d032025a.4-9-AEO2025&map=&sourcekey=0.

[209] NERC defines Tier 2 resources as those having one of the following characteristics: "Signed/approved Completion of a feasibility study, Signed/approved Completion of a system impact study, Signed/approved Completion of a facilities study, Requested Interconnection Service Agreement, Included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs)." NERC, 2024Long Term Reliability Assessment, 137 (Dec. 2024, updated July 15, 2025) https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

[210] IPI Report, Ex. 16 at 23.

historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region."[211] For example, for the PJM region, the Independent Market Monitor's analysis shows that 15% of generation projects (on an energy basis) successfully enter service.[212] As of late 2024, PJM had over 44 GW of accredited capacity in its interconnection queue.[213] To assume that none of this capacity would enter service by 2030, as DOE's analysis does, is unreasonable.

Such an analysis should also consider factors pointing towards even faster queue times than those seen in the historical data, given factors now expediting interconnection queues such as implementation of FERC Order 2023, streamlining of tools to better utilize existing points of interconnection (e.g., surplus interconnection service), and various interconnection fast tracks that FERC has recently approved.[214] For example, it is unreasonable for DOE to exclude from consideration the over 9 GW of accredited capacity that PJM selected in May 2025 to participate in its Reliability Resource Initiative—the vast majority of these projects (primarily gas and battery energy storage systems) are committed to be online by 2030,[215] but are omitted in DOE's analysis because they do not yet have a signed interconnection agreement. DOE paints an inaccurate picture of new entry by ignoring recently adopted policies designed to address the very same tightening supply and demand conditions that DOE describes.

DOE also underestimates the extent to which interregional transfers of energy could help to prevent or address any shortfalls. Noting that it relies upon the interregional transfer capacities identified by NERC in its Interregional Transfer Capability Study, DOE explains that "[i]mports are assumed to be available up to the minimum total transfer capacity and spare generation in the

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[211] *Id.*

[212] Monitoring Analytics, 2024 State of the Market Report, at 705 (2024) https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2024/2024q2-som-pjm-sec12.pdf (noting 14.9% completion rate).

[213] PJM, Reliability Resource Initiative MRC Update, at slide 6 (Nov. 7, 2024) https://www.pjm.com/-/media/DotCom/committees-groups/committees/mrc/2024/20241107-special/item-04---reliability-resource-initiative---presentation.ashx.

[214] *Id. See also* Prefiled Statement of Manu Asthana on Behalf of PJM Interconnection, L.L.C., FERC Docket No. AD25-7, at 4 (May 27, 2025), https://www.ferc.gov/media/manu-asthana-pjm-president-and-ceo (touting recent improvements to PJM's interconnection queue by noting that "[a]n additional approximately 18 GW is being processed to move to the final study phase for completion this year, and an additional 56 GW (including projects from Transition Cycle 2 and Reliability Resource Initiative) will be through the queue by late 2026.").

[215] PJM, Reliability Resource Initiative Results Summary, at slide 9 (May 6, 2025) https://www.pjm.com/-/media/DotCom/committees-groups/committees/pc/2025/20250506/20250506-item-06---reliability-resource-initiative---summary-results.pdf.

neighboring subregion."[216] Because the Interregional Transfer Capability Study calculated interregional transfer capacities for both summer and winter, and for each direction of flow, it is unclear what DOE means regarding allowing transfers up to the minimum. As the IPI observes: "If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity."[217] This is yet another example of where DOE fails to explain its methodology with sufficient detail to enable an evaluation of whether its approach is reasonable, or is supported by substantial evidence.

4. DOE's use of a deterministic analysis provides an incomplete and inaccurate picture.

For the RAR, DOE employs a deterministic approach in examining resource adequacy; that is one that "evaluate[s] resource adequacy using relatively stable or fixed assumptions about the representation of the power system," rather than a probabilistic approach that "incorporate[s] data and advanced modeling techniques to represent uncertainty that require more computing power."[218] DOE explains it chose a deterministic approach "for transparency and to model detailed historic system conditions."[219] However, deterministic approaches have significant limitations; as NERC explained in the Interregional Transfer Capability Study on which DOE otherwise heavily relies, because that study did not employ a probabilistic approach, it "should not be considered a North American resource adequacy assessment."[220] The problem, as IPI explains, is that "[b]y examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty."[221] Furthermore, as NERC itself has explained, under a deterministic approach, "some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future."[222] As IPI concludes, neither of DOE's professed reasons for using a deterministic approach justifies departing from best practices, as "DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach."[223]

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[216] RAR, Ex. 1 at 12.

[217] IPI Report, Ex. 16 at 26.

[218] RAR, Ex. 1 at 2 n.2.

[219] *Id.*

[220] IPI Report, Ex. 16 at 21 (citing NERC, Interregional Transfer Capability Study, at 4 (2024) (hereinafter "NERC ITCS")).

[221] IPI Report, Ex. 16 at 21.

[222] *Id.* (citing NERC ITCS at 138).

[223] *Id.* at 21.

DOE may have chosen a less sophisticated and rigorous approach given the limited amount of time in which the Grid EO required this analysis to be completed, but regardless of the reason, the limitations inherent in DOE's deterministic methodology mean that its findings should not be taken as conclusive or form the basis for further extraordinary actions.[224]

5. DOE uses an elevated threshold for determining when outages will occur.

In the RAR, the Department projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[225] This approach, and the particular values used as thresholds, come from the NERC Interregional Transfer Capability Study, which uses 3% as the default threshold and 6% only in a sensitivity analysis. NERC explains that the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" in order for a Balancing Authority to continue to hold the minimum reserves needed to protect the system from cascading or widespread outages.[226] In the sensitivity examined by NERC, using the 6% threshold "significantly altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida."[227]

As the IPI analysis notes, DOE provides no further explanation for when and how it uses 6% as a threshold versus 3%.[228] While the Department directs readers to an appendix with further detail, the appendices do not in fact provide any further information regarding this critical assumption.[229] Furthermore, "the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis," and that if "DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate the extent of expected outages."[230] DOE's failure to explain its own methodology concerning such a critical input to its analysis, including through the failure to provide information in an appendix that the RAR states exists, renders the RAR arbitrary and capricious. Insofar as the RAR's results for 2030 scenarios depend upon the 6% threshold, DOE must explain why

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[224] *Id.* ("Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.")

[225] RAR, Ex. 1 at 12.

[226] IPI Report, Ex. 16 at 22 (citing NERC ITCS, at 91 n.90, 85).

[227] IPI Report, Ex. 16 at 22 (citing NERC ITCS at 105 tbl.8.4); *see also id.* ("Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.")

[228] IPI Report, Ex. 16 at 22.

[229] *Id.*

[230] *Id.*

such a threshold is appropriate, given the departure from NERC's practice and the evidence in the NERC report considering the propriety of a far lower threshold.

6. DOE inconsistently applies its own methodology.

Several of the findings in the RAR are inconsistent with the methodology that DOE develops. For instance, DOE states that "[a]nalysis of the current system shows all regions except ERCOT have less than 2.4 hours of average loss of load per year and less than 0.002% NUSE" (the standards DOE developed for this study).[231] DOE further explains that "[w]hen looking at metrics in the worst weather years, regions meet or exceed additional criteria. All regions experienced less than 20% of lost load in any hour."[232] Despite these clear findings, DOE goes on to state that "PJM, ERCOT, and SPP experienced significant loss of load events during 2021 and 2022 winter storms Uri and Elliot which translated into more than 20 hours of lost load," and asserts that this "results in a concentration of lost load within certain years such that some regions exceeded 3-hours-per-year of lost load."[233] As an initial matter, the PJM system did not experience any lost load due to resource inadequacy during Winter Storms Uri or Elliott.[234] Second, DOE's focus on whether a region had lost load or a risk of lost load in a particular weather year is inconsistent with DOE's own articulation of its resource adequacy standards, as "average indicators" assessed across all scenarios and years.[235] As the IPI notes, these standards are "not a requirement that must be achieved in each and every scenario."[236]

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[231] RAR, Ex. 1 at 7.

[232] *Id.*

[233] *Id. See also Id.* at 9 ("For the current system, this analysis identifies an additional 2.4 MW of capacity to meet the NUSE target for PJM, which experiences shortfalls due to the winter storm Elliot historical weather year.").

[234] PJM Inside Lines, PJM Releases Winter Storm Elliott Report (July 17, 2023) https://insidelines.pjm.com/pjm-releases-winter-storm-elliott-report/ ("PJM maintained system reliability and served customers throughout the extreme weather that affected the region Dec. 23–25 [2022], and even was able to support its neighbors during certain periods."); *see also* FERC, NERC and Regional Entity Staff Report, *The February 2021 Cold Weather Outages in Texas and the South Central United States* (Nov. 16, 2021), https://www.ferc.gov/media/february-2021-cold-weather-outages-texas-and-south-central-united-states-ferc-nerc-and (noting that PJM was exporting power to neighboring regions during Winter Storm Uri, and investigating rolling blackouts only in Texas and south central states).

[235] RAR, Ex. 1 at 5.

[236] IPI Report, Ex. 16 at 20.

D. Notice and Comment Procedures Are Required for Any "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the Administrative Procedure Act, federal agencies must provide notice and an opportunity for public comment when issuing rules, with limited exceptions not applicable here.[237] If the RAR is, as the Department claims on page vi, a "uniform methodology" for agency decisionmaking on reliability interventions, then the Department needed to provide notice and seek and respond to public comment on this methodology. The Department cannot slip in "entirely new information critical" to its "determination[s]" without taking and responding to public comment.[238]

In the past, when the Department sought to create uniform triggers for reliability intervention within its authority, it issued notice and sought comment.[239] If the RAR is a "uniform methodology" for reliability interventions, then the Department has effectively amended those prior regulations on reliability interventions without following legally required procedures. For example, the Department has regulations defining "emergency" and setting forth procedures for an applicant to demonstrate an "emergency" in the context of Federal Power Act Section 202(c) orders.[240] If the RAR is now a mandatory factor in determining whether there is an "emergency," the Department has changed its existing regulations without following required notice and comment procedures.

E. NEPA Procedures Must Be Followed for Any RAR on Legislative Proposals or "Uniform Methodology" the Department Uses to Guide Reliability Interventions.

Under the National Environmental Policy Act ("NEPA"), agencies must include a "detailed statement" on the environmental impacts of a proposed action "in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment."[241] If the RAR is a "uniform methodology" for agency decisionmaking on reliability interventions, it qualifies as a major federal action requiring, at a minimum, an Environmental Assessment and most likely, under the circumstances, a full

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[237] 5 U.S.C. §§ 553(b), (c).

[238] *Am. Pub. Gas Assoc. v. DOE*, 72 F.4th 1324, 1338 (D.C. Cir. 2023) (cleaned up).

[239] *See* Grid Security Emergency Orders: Procedures for Issuances, 83 Fed. Reg. 1174 (Jan. 10, 2018) (final rule on Federal Power Act section 215A procedures issued after notice and comment); Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39,984 (Aug. 6, 1981) (final rules concerning emergency interconnections under Federal Power Act sections 202(c) and 202(d) issued after notice and comment).

[240] 10 C.F.R. §§ 205.371; 205.373.

[241] 42 U.S.C. § 4332(C).

Environmental Impact Statement. However, the RAR does not contain any statement whatsoever, and certainly no "detailed statement," on environmental impacts.

Yet the RAR purports to guide "government decisionmakers" on one of the most significant issues that affect the environment—electricity generation. The electricity sector is responsible for wide-ranging environmental impacts—from smog to greenhouse gas emissions to toxic metals to acid rain.[242] Uniform rules on reliability interventions would significantly affect the environment because some of these reliability interventions allow environmental rules for electricity generators to be waived.[243]

VI. CONCLUSION

For the reasons set forth above, the undersigned Public Interest Organizations respectfully request that the Department withdraw the RAR. In the alternative, the Department should not use the RAR as support for any reliability intervention or other action until and unless it (1) provides notice of the statutory authority under which DOE issued the RAR and publishes all data underlying the RAR, (2) provides a detailed explanation of the specific uses for the methodology, and (3) allows interested parties to comment on the RAR before finalizing it.

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[242] *See* EPA, Human Health & Environmental Impacts of the Electric Power Sector (Feb. 6, 2025) https://www.epa.gov/power-sector/human-health-environmental-impacts-electric-power-sector.

[243] *See* 16 U.S.C. § 824a(c)(4)(A).

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-40a:
Department's Response to PIOs' RFR of July Resource Adequacy Report

Department of Energy
Washington, DC 20585

September 5, 2025

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RE: August 8, 2025 Submission

To Whom It May Concern:

Thank you for your August 8, 2025 submission on behalf of the Natural Resources Defense Council, the Ecology Center, the Environmental Defense Fund, the Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar (collectively, the Public Interest Organizations). The submission was titled "Motion to Intervene and Request for Rehearing of Natural Resources Defense Council, the Ecology Center, Environmental Defense Fund, Environmental Law and Policy Center, Public Citizen, Sierra Club, and Vote Solar" (Submission). It was not filed in any active docket.

On July 7, 2025, the U.S. Department of Energy (DOE) issued the Report on Strengthening U.S. Grid Reliability and Security (Resource Adequacy Report or RAR), fulfilling Section 3(b) of Executive Order 14262. The RAR presents a unified, transparent methodology for assessing the reliability of the bulk power system and identifying regions at elevated risk of resource inadequacy under projected load growth and plant retirement scenarios. DOE developed this approach in coordination with NERC and leading industry experts to provide a consistent, data-driven framework for informing federal reliability interventions, particularly as the grid faces surging demand from AI-driven data centers, reindustrialization, and electrification.

In the Submission, the Public Interest Organizations seek rehearing of the RAR under section 313 of the Federal Power Act (FPA).[1] An application for rehearing under section 313 of the FPA[2] may be filed only by a "person, electric utility, State, municipality, or State commission" that is "aggrieved" by "an order issued by [DOE]."[3] If these prerequisites are not met, there is no basis for rehearing. Here, we note that the RAR is simply a report that details the current condition of the United States electrical grid. It contains no directives, nor does it impose legal duties upon any party, including the Public Interest Organizations. As such, it cannot be considered an "order" by which the Public Interest Organizations are "aggrieved" within the meaning of section 313 of the FPA, as would be required to request rehearing. Accordingly, DOE will take no action on the Submission.

---

[1] Submission at 1.
[2] 16 U.S.C. § 825*l*(a).
[3] *Id.*

Sincerely,

Tina Francone
Director of the Grid Deployment Office, Acting

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-41:
Inst. Pol'y Integrity Report



Enough Energy

A Review of DOE's Resource Adequacy Methodology

Jennifer Danis
Christoph Graf, Ph.D.
Matthew Lifson

July 2025

Institute *for*
Policy Integrity
NEW YORK UNIVERSITY SCHOOL OF LAW

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The authors thank Dr. Adria Brooks and Rob Gramlich for their valuable feedback.

This report does not purport to present the views, if any, of NYU School of Law.

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Executive Summary

On April 8, 2025, President Trump issued an Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) requiring the Department of Energy (DOE) to (1) "identify current and anticipated regions with reserve margins below acceptable thresholds" and (2) "establish . . . a protocol to identify which generation resources within a region are critical to system reliability."[1] DOE responded on July 7, 2025 with its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[2]

This report reviews best practices for analyzing whether a region is resource adequate and for identifying whether a particular resource is critical for resource adequacy. It next analyzes the DOE Study as compared to those best practices. Finally, it examines next steps for U.S. resource adequacy policy following the DOE Study, in light of different entities' respective authorities over the issue.

In Part 1, this report outlines a four-step process for evaluating whether a region is resource adequate and then identifying which resources are critical. Each step involves choices between traditional methods and best practices adapted to the evolving risks posed by the energy transition and the new conditions brought about by climate change.

- *Step 1*: *Set a Resource Adequacy Target*: Planners should define resource adequacy targets using a multi-metric approach that captures not just outage frequency but also magnitude and duration, possibly supplemented by metrics focused on tail risks instead of expected values. Targets should be region-specific and reflect a local cost-benefit analysis that weighs the incremental benefits and costs of achieving reduced outages.
- *Step 2: Conduct Resource Adequacy Modeling:* Rather than focusing narrowly on annual peak load, planners should assess whether a region achieves the target from Step 1 by modeling all 8,760 hours of the year in chronological order using probabilistic techniques that account for uncertainty like the Monte Carlo method. Best practices include incorporating weather-linked dependencies; climate-adjusted inputs; and realistic assumptions about retirements and additions, interregional imports, and storage and demand response dynamics. This modeling more accurately reflects the risks posed by variable generation and energy-limited resources.
- *Step 3: Establish Accreditation Values:* Resource accreditations—the specific contribution of a resource or resource type to resource adequacy—should be derived from Step 2's probabilistic modeling of a resource's ability to contribute during hours of highest risk.

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1 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

2 U.S. Dep't of Energy, Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid (2025), https://perma.cc/A587-S88S.

Effective Load Carrying Capability or related probabilistic methods should be applied to all resource types, including thermal plants, to accurately describe their contributions under a wide range of possible futures and hard-to-predict risk periods. Accreditation methods should be applied equally to thermal and variable resources to allow for technology-neutral comparisons.

- *Step 4: Calculate the Reference Margin Level and the Reserve Margin:* Using the resource adequacy modeling and accreditation values from Steps 2 and 3, planners should calculate a reference margin level—the amount of accredited capacity that corresponds to achieving the resource adequacy target. Comparing a region's actual resource fleet to this benchmark allows planners to determine whether the exit or entry of specific resources would affect achievement of the reference margin level and thus the resource adequacy target, given the resources' accreditations.

Part 2 compares the best practices from Part 1 to DOE's methodology in the DOE Study—in which DOE concluded that all transmission planning regions except ERCOT are currently resource adequate but that all regions except ISO-NE and NYISO will be resource inadequate in 2030. Across multiple dimensions, DOE's approach departs from best practices in ways that call these results into question.

- *Resource Adequacy Targets:* DOE's use of a multi-metric standard—2.4 hours of lost load per year and 0.002% normalized unserved energy—is consistent with best practices, but the choice of values is not. Neither value is appropriately justified based on a cost-benefit framework, and the use of a one-size-fits-all target for the entire country ignores regional differences. Additionally, DOE inappropriately attempts to label PJM as currently resource inadequate even though the region achieves DOE's own target according to DOE's modeling.

- *Resource Adequacy Modeling:* DOE models all 8,760 hours of the year chronologically but relies on a deterministic rather than probabilistic framework, limiting its ability to assess uncertainty or tail risks. This less accurate approach evaluates adequacy only under a fixed set of historical weather and load years. Further, DOE's truncated description of how its model decides whether an outage has been triggered makes this assumption impossible to fully evaluate, but DOE's limited explanation does suggest that it may have adopted an overly conservative approach that exaggerates resource adequacy risk. Finally, DOE's 2030 results are significantly shaped by unrealistic assumptions about additions, retirements, load, and possibly interregional imports.

- *Accreditation and Reference Margin Levels:* The DOE Study does not attempt to identify resources that are critical for any region's resource adequacy, and thus does not calculate accreditation values or reference margin levels. But DOE does estimate the amount of perfect capacity required to bring certain regions to the 0.002% NUSE target. DOE could build upon this approach in the future to calculate reference margin levels, but any future efforts should attend to all prongs of its multi-metric resource adequacy target. Additionally, DOE's perfect capacity additions inexplicably bring regions far beyond 0.002% NUSE, meaning that DOE overstates how difficult it would be to cure the purported resource adequacy shortfalls.

Part 3 answers what should happen next for U.S. resource adequacy policy now that DOE has published its study.

- Given how DOE's statutory authority under Section 202(c) of the Federal Power Act is limited to emergencies, DOE's own conclusion that most regions are not currently experiencing resource adequacy shortfalls suggests that DOE has limited legal authority to address potential problems in 2030. Moreover, the limitations of the DOE Study call into question the accuracy of DOE's forecasts.
- Instead of DOE, the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation could more appropriately—and less intrusively from the perspective of states, grid operators, and markets—support resource adequacy by issuing reliability standards that require best practices for regions' resource adequacy efforts. Rather than establishing a national resource adequacy target, these standards would govern how regions select resource adequacy targets, evaluate if they are achieving them, and measure the contributions of specific resources. This step would be in line with the Federal Energy Regulatory Commission's Order No. 747, which approved analytical guardrails for resource adequacy analysis for a portion of the U.S.

Introduction

How does a regional electric grid operator know when its region has enough electricity to meet demand and whether any specific generation resource, like a particular coal plant, is essential for doing so? President Trump's Executive Order on Strengthening the Reliability and Security of the United States Electric Grid (the EO) implicates these questions: The EO directs the Department of Energy (DOE) to assess if each region of the United States has sufficient energy resources to meet current and future demand, and to identify and retain critical resources.[3] On July 7, 2025, DOE responded to the EO by publishing its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study).[4]

This report addresses the EO and the DOE Study's fundamental concern: resource adequacy. Resource adequacy is one key aspect of a power system's reliability. It refers to a system's "ability . . . to generate and transmit adequate quantities of electricity to meet demand, taking into account scheduled and reasonably expected unscheduled system outages."[5] Resource adequacy thus concerns whether a system's supply of energy exceeds demand. Determining whether an area is resource adequate is, however, ultimately a policy question, rather than an engineering one, because it would be prohibitively expensive to build a system that serves 100% of demand under all conditions.[6] Deciding whether a region is resource adequate always explicitly or implicitly balances society's desire for reliable electricity with the cost of providing that reliability.

Starting from first principles, Part 1 examines how to determine whether a region meets its selected resource adequacy target and how a planner can know whether any one particular resource is critical for resource adequacy. Part 2 discusses whether the DOE Study reflects, rejects, or obscure these first principles. Part 3 explores next steps for U.S. resource adequacy policy following the publication of the DOE Study, considering the respective roles of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), DOE, grid operators, and states.

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3 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

4 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2.

5 Burçin Ünel & Avi Zevin, Inst. for Pol'y Integrity, Toward Resilience: Defining, Measuring, and Monetizing Resilience in the Electricity System 11 (2018), https://perma.cc/UDB5-DEEM (citing a NERC "Frequently Asked Questions" page that is no longer available).

6 Energy Sys. Integration Grp., New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements 38 (2024), https://perma.cc/NXU4-N4UG.

Part 1: Best Practices for Resource Adequacy

The EO requires DOE to evaluate the sufficiency of regions' "reserve margins" and establish a resulting protocol to identify "critical" resources that should be retained.[7] To figure out what kind of buffer will ensure that a region achieves a given level of resource adequacy, and to label specific generators as essential for that resource adequacy, a planner would need to undertake a four-step process. At each step, the planner must pick between antiquated approaches and newer best practices.

First, the planner must make the policy choice of selecting a resource adequacy target for the region that, if achieved, would indicate resource adequacy. Second, it should use resource adequacy modeling to determine whether a region has achieved and will continue to achieve the selected target under foreseeable future conditions. Third, the planner should use its resource adequacy modeling with accurate data curation to derive how each generation and storage resource contributes to meeting the target (their "accreditation" values). Fourth, it should use the resource adequacy modeling plus resources' accreditation values to derive an acceptable reserve margin for the region (the "reference margin level"). At this fourth step, the planner can use the accreditation values to check whether the exit of a particular resource would cause a region to dip below the reference margin level.

These best practices have largely emerged to address the resource adequacy challenges caused by the energy transition and extreme weather events caused by climate change. Whereas traditional methods have focused on whether demand would exceed supply during peak load hours, system risk has shifted to *net* peak hours, i.e., when load minus variable generation is highest.[8] Measuring whether supply will meet demand has itself become more complicated. Increasingly, it has become important to perform modeling resource adequacy chronologically—each hour reflecting the conditions that came before it—to account for the dynamics of battery storage resources and demand response.[9] And policymakers now are also confronting the outdated idea that thermal resources are "perfect" capacity, given their weather-related vulnerabilities.[10]

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7 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

8 Juan Pablo Carvallo et al., Lawrence Berkeley Nat'l Lab'y, A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions 13 (2023), https://perma.cc/5VLY-B7HF.

9 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, Evolving Planning Criteria for a Sustainable Power Grid: A Workshop Report 9 (2024), https://perma.cc/KE8D-W6VX.

10 Nat'l Ass'n of Regul. Util. Comm'rs, Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms 32–34 (Nov. 2023), https://perma.cc/K88X-2JCR.

Step 1: Pick a Resource Adequacy Target

Before any analysis can determine if a system is resource adequate, policymakers must set a clear resource adequacy *target*.[11] This first step involves two distinct choices: (1) selecting one or more metrics to represent the variables by which resource adequacy will be judged, and (2) setting the numerical values for those chosen metrics to achieve the resource adequacy target.

Consider what it would take to set a target, not for resource adequacy, but for human health. First, you would pick the metrics that you think would best define whether a person is healthy, e.g., blood pressure, resting heart rate, or cholesterol levels. Using only one metric would not give you enough information. And paying attention to only each metric's average levels without also examining whether the metric ever reaches dangerous levels could obscure risk of a catastrophic health event. Second, you would pick a value for each metric, like a blood pressure of less than less than 120/80 mmHg. To pick that value, you would consider the best available evidence on what level is optimal.

Similarly, when it comes to resource adequacy, the best practice is to move beyond the standard approach of attending primarily to the *frequency* of outages and to also consider their *magnitude* and *duration*. Additionally, regions should consider metrics focused on the extremes of the probability distribution, rather than expected value metrics that could label a system as resource adequate when a low probability (but plausible) event would be catastrophic.

When selecting numerical values for the chosen resource adequacy metrics, the best practice is to consider the best available evidence on the tradeoff between the benefits and costs of additional resource adequacy. The optimal level of resource adequacy may be different in each region, depending on the local costs of the investments that would be needed to reduce shortfall events and the local consequences of a shortfall.[12] A resource adequacy target should ideally represent the level of resource adequacy that the system planner has identified as socially optimal because it balances costs and benefits.

Metrics

Historically, U.S. policymakers have framed their resource adequacy targets in terms of loss of load expectation (LOLE),[13] and this metric remains widespread.[14] LOLE typically refers to the number of days per year in which an outage occurs and is largely a measure of frequency.[15]

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11 *See* Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 2 tbl.1.

12 *Id.* at 39, 41.

13 Elec. Power Rsch. Inst., Metrics and Criteria: Insights from Case Studies and Recommendations and Considerations for Future Practice 31 (2024), https://perma.cc/W4VF-VQPD.

14 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8 tbl.2.

15 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future 3, 8 (Apr. 2022), https://perma.cc/7G9V-CNWB. Technically, the number of days per year in which an outage occurs is "loss of load days" (LOLD), which is a special case of the broader concept of LOLE, which can be used with different event-periods. *Id.* at 7–8. In North America, however, LOLE typically means LOLD. *Id.* at 7; *accord* Gord Stephen et al., *Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric* at 2, https://perma.cc/A9DJ-C3B5.

Frequency is an important characteristic to track because consumers prefer fewer outages.[16] LOLE coarsely accounts for duration, too, in that an outage that stretches multiple days will count as an additional event for each additional day.

LOLE does, however, obscure important aspects of resource adequacy. It will not differentiate between (1) a 10-hour event with 1 GWh of load shed that is followed by a second identical event within the same day and (2) a 30-minute event with 5 MWh of load shed. Customers are not indifferent, however, between these two situations.[17] Because damages depend on outages' frequency, magnitude, and duration, LOLE neglects key dimensions of resource adequacy affecting customers' wellbeing.[18] Attending to these characteristics when setting resource adequacy targets is more important than ever, because changes in the resource mix and extreme weather due to climate change mean that loss-of-load events have become less uniform and thus less interchangeable.[19]

The Multi-Metric Approach

The best practice is to supplement the traditional LOLE metric (or a different frequency-focused metric like "loss of load events," which separately counts all events within a year and thus differentiates between events that occur during the same day[20]) with additional metrics that capture other dimensions of resource adequacy.[21] Both the Electric Reliability Council of Texas (ERCOT) and the Northwest Power and Conservation Council (NWPCC) have done exactly this, augmenting their LOLE-based targets to include magnitude and duration metrics.[22] Under a multi-metric approach, a system could be declared resource adequate if it achieves selected value targets for each and every metric,[23] or if it achieves some minimum number or combination of the metrics (e.g., any two of a system's three metrics).[24]

A leading magnitude metric that could be incorporated into a multi-metric approach is expected unserved energy (EUE): the amount of demand that the system will fail to serve during a period, typically a year.[25] A region's EUE can be contextualized by dividing it by the region's total annual load—this is called normalized unserved energy (NEUE).[26] Australia uses an annual unserved

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16 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

17 *Id.* at 3.

18 *Id.* at 10.

19 *Id.* at 11, 15, 22.

20 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

21 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 33–37; Elec. Power Rsch. Inst., Resource Adequacy Philosophy: A Guide to Resource Adequacy Concepts and Approaches 23 (2022), https://perma.cc/ZH4Y-ZD7J; Juan Pablo Carvallo et al., *supra* note 8, at 28–29; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at vii.

22 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

23 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 35.

24 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 31–32.

25 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 17.

26 *Id.* at 18.

energy metric,[27] as does NWPCC.[28] Planning around these magnitude metrics can help a region avoid catastrophic events associated with significant unserved energy.[29]

But, like LOLE, magnitude-focused metrics like EUE and NEUE are incomplete alone; they do not account for how the unserved energy is distributed throughout the year.[30] An alternative or complementary magnitude metric is "peak shortfall," defined as the largest expected outage of the period.[31] Peak shortfall is potentially useful because damages from a single outage increase nonlinearly with its scale.[32] Both ERCOT and NWPCC have versions of a peak shortfall metric (NWPCC's complements its EUE metric).[33]

For duration, a popular metric that could supplement frequency and magnitude metrics is loss of load hours (LOLH), which measures the number of hours per year in which an outage occurs.[34] LOLH fundamentally resembles LOLE, but is more granular because it analyzes each hour, rather than each day. As such, LOLH does a better job at expressing the aggregate duration of all shortfalls in a region.[35]

Many countries use LOLH as their sole resource adequacy metric,[36] but, in aggregating hours, it neglects the duration of individual events—even though damages increase nonlinearly with an outage's duration.[37] Supplemental metrics such as average shortfall duration[38] and the maximum shortfall length (used in Texas and NWPCC)[39] can capture this aspect of duration.

Accounting for Tail Risks

Beyond questions of frequency, magnitude, and duration, a separate question when using any chosen metric is whether to look at the mean of the distribution, extremes, or both. Traditionally, regions have framed their LOLE, EUE, and LOLH goals in terms of their *mean* values.[40] But the energy transition and climate change have increased the risk of extremely damaging tail risks,[41]

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27 *Id.* at 9.

28 Nw. Power & Conservation Council, *supra* note 22.

29 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 19 tbl.4.

30 *Id.*

31 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide 18 (2024), https://perma.cc/CB7Q-MXZM (using the equivalent phrase "MW Short").

32 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 3.

33 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

34 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 8.

35 *Id.* at 8.

36 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8.

37 *Id.* at 3.

38 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

39 Reliability Standard for the ERCOT Region, No. 54584, 2024 WL 4263493, at *24 (Tex. Pub. Utils. Comm'n Sept. 9, 2024); *Resource Adequacy*, Nw. Power & Conservation Council, https://perma.cc/39P6-VBNN.

40 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment 4 (2023), https://perma.cc/M3A5-2WAL; Juan Pablo Carvallo et al., *supra* note 8, at 12.

41 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 22.

making it increasingly appropriate to factor these risks into regions' metrics.[42] When it comes to resource adequacy, customers care not just about how the how severe and common outages will be on average, but also about how bad the worst outages they will experience could be.

One option for assessing these potentially severe consequences is the "value at risk" method. This method defines the selected metric (whether it is focused on frequency, magnitude, or duration), not in terms of its expected value, but in terms of how bad some relatively unlikely but still plausible scenario would be.[43] For example, one of NWPCC's metrics is the maximum shortfall length, framed in terms of what the maximum shortfall length will be at the 97.5th percentile of the distribution, i.e., how long the shortfall would be if there were only a 2.5% chance that the shortfall could be longer.[44] Planners can also frame a metric both in terms of expected value *and* value at risk for the same system: Belgium previously had an LOLE metric that simultaneously required an expected value of less than 3 LOLH and required the 95th percentile of the distribution to be less than 20 LOLH.[45]

An alternative to the value at risk method is the "conditional value at risk" method, in which the metric is framed not in terms of the value at some percentile of the distribution, but in terms of the average value of the distribution beyond the percentile.[46] Policymakers' preference between these two options will depend on their risk tolerance, as the value at risk method will equally weight all tail events while the conditional value at risk method effectively places more weight on extreme events even within the tail.[47]

Values

After picking resource adequacy metrics—whether singular or multi-valued, and based on expected values, tail risks, or a combination of the two—the second step for setting a resource adequacy target is picking the numerical value for the metric(s). In the U.S., the most common value for the LOLE metric is 0.1, i.e., outages should occur no more than 0.1 days per year.[48] Selecting a value inherently involves balancing customers' desire for resource adequacy with the cost of achieving it.[49]

Notwithstanding that tradeoff, U.S. resource adequacy planners have largely set these values without any economic analysis. The origin of the widespread 0.1 LOLE target is somewhat enigmatic, especially relative to its contemporary significance, but it appears to describe the

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42 *See* Juan Pablo Carvallo et al., *supra* note 8, at 29; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 8; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

43 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27.

44 Nw. Power & Conservation Council, Pacific Northwest Power Supply Adequacy Assessment for 2029 12 (2024), https://perma.cc/GZY2-PKY7.

45 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 17.

46 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 26–27; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 10.

47 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 27 fig.8.

48 *Id.* at 8.

49 *Id.* at 38.

level of resource adequacy that happened to exist in the 1940s.[50]

The values used in NERC's reports on regions' long-term resource adequacy similarly seem arbitrary. NERC uses a LOLH metric, labeling regions with greater than 2.4 LOLH as high risk, 0.1-2.4 as elevated risk, and less than 0.1 as normal risk. NERC does not explain the basis for these categories, but they appear to stem this from a common (but widely criticized) hourly conversion of the 0.1 LOLE standard.[51] And NERC's values for the NEUE metric—above 0.002% is high risk, less than 0.002% but above zero is elevated risk, negligible or zero is normal risk—is adapted from Australia's 0.002% NEUE target without considering the different national contexts.[52] Context matters because the U.S. and Australia may vary in terms of how damaging outages would be (e.g., how bad it would be to lose electric heating and cooling in light of the region's temperatures) and how expensive it would be to avert them (e.g., the country-specific cost of building a natural gas peaker plant).

A better practice would be to use economic principles to select a socially efficient resource adequacy target, i.e., to select the value at which the incremental costs of additional resource adequacy equal the incremental benefits of achieving it.[53] Where policymakers do estimate the *costs* of improving resource adequacy, they often turn to the concept of "cost of new entry" (CONE).[54] CONE, expressed in $/MWh, represents the marginal investment and fixed costs of adding additional capacity to the system to achieve a more stringent resource adequacy standard.[55] Historically, planners assumed the marginal resource was a combustion turbine, but today it is more accurate to assume a portfolio of diverse resources.[56] Considering CONE by itself, however, does not accurately capture the social marginal cost of achieving higher levels of resource adequacy, because adding capacity can have follow-on effects like reducing the cost of energy.[57] Accordingly, it is better to estimate total net CONE, which nets out potential system benefits such as reduced energy costs for loads and lower operating costs.[58]

To estimate the *benefits* of additional resource adequacy, planners typically rely on the value of lost load (VOLL).[59] The VOLL represents the societal cost of failing to serve a unit of energy

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50 Kevin Carden et al., Nat'l Regul. Rsch. Inst., The Economics of Resource Adequacy: Why Reserve Margins Are Not Just About Keeping the Lights On 2 (2011), https://perma.cc/LS2F-2EZR; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

51 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment 11–12 (2024), https://perma.cc/GJB2-VCZQ; Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

52 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

53 Kevin Carden et al., *supra* note 50, at 1; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 38–42; Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

54 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 13, 41–42.

55 *Id.* at 42.

56 *Id.*

57 Christoph Graf et al., *Cost-Effective Capacity Markets* 29, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4864513 (posted June 21, 2024); Kevin Carden et al., *supra* note 50, at 8–9.

58 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 42.

59 Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

demanded by consumers and is denominated in $/MWh.[60] Estimates vary significantly across customer classes,[61] but modelers can capture this through averaging.[62] More challenging is capturing how the VOLL varies with an outage's particular characteristics. For relatively short outages, the first hour tends to the most expensive,[63] indicating that many frequent outages could be more socially disruptive than a consolidated one of equal length. Long-duration outages result in damages that increase nonlinearly (food spoilage, jeopardized medical care, and loss of access to safe drinking water).[64] Similarly, the VOLL can increase nonlinearly with magnitude: When the grid operator can no longer manage the situation through rotating outages, the resulting uncontrolled outage is much more damaging.[65] Accordingly, undertaking a cost-benefit analysis that allows VOLL to vary with duration and magnitude would produce a more accurate, cost-benefit-justified resource adequacy target.

Many jurisdictions use some version a cost-benefit analysis when setting their resource adequacy targets. In the European Union, countries solve for their specific LOLH targets by dividing a local CONE value by the local VOLL, which, in 2023, resulted in a range from 1 LOLH (Sweden) to 15 LOLH (Czechia).[66] The United Kingdom uses this same approach.[67] Australia periodically reviews its 0.002% NEUE target to ensure that the implied "value of customer reliability," which is akin the VOLL, is close to its estimated value.[68] Somewhat analogous to these examples, the administratively set, downward-sloping demand curves for capacity markets in U.S. regions like PJM embody the tradeoff between the benefits and costs of additional resource adequacy, because the curves dictate how much regions are willing to pay for each increment of additional capacity given the capacity's incremental benefits.[69] Technically, though, this cost-benefit thinking happens not when *setting* the resource adequacy target, but in deciding whether to under-, over-, or exactly *achieve* an already-determined target.

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60 Jennifer Danis et al., Inst. for Pol'y Integrity, Transmission Planning for the Energy Transition: Rethinking Modeling Approaches 6 (2023), https://perma.cc/5A6L-DJHL.

61 Michael J. Sullivan et al., Ernest Orlando Lawrence Berkeley Nat'l Lab'y, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States xii, tbl.ES-1 (2015), https://perma.cc/CT53-8WEA.

62 *See* Elec. Power Rsch. Inst., Metrics and Criteria, *supra* note 13, at 35.

63 Michael J. Sullivan et al., *supra* note 61, at xii, tbl.ES-1.

64 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 23 fig.5.

65 *See, e.g.*, Joshua W. Busby et al., *Cascading Risks: Understanding the 2021 Winter Blackout in Texas*, 77 Energy Rsch. & Soc. Sci. (2021); Sergio Castellanos et al., *A Synthesis and Review of Exacerbated Inequities from the February 2021 Winter Storm (Uri) in Texas and the Risks Moving Forward*, 5 Progress in Energy (2023); Hassan Haes Alhelou et al., *A Survey on Power System Blackout and Cascading Events: Research Motivations and Challenges*, 12 Energies 1, 16–17 (2019).

66 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 39 fig.12, 40.

67 *Id.* at 40.

68 Reliability Panel AEMC, Final Report: Reliability Standard and Settings Review 2018 i, 14 (2018), https://perma.cc/TAN8-TPXZ.

69 *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 76 (2006) ("In addition, we agree with PJM that a downward-sloping demand curve provides a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. Under a vertical demand curve, capacity above the Installed Reserve Margin is deemed to have no value. Incremental capacity above the Installed Reserve Margin is likely to provide additional reliability benefits, albeit at a declining level. This value is reflected in the positive (but declining) prices in the sloped demand curve to the right of the Installed Reserve Margin, but is not reflected in the current capacity market.").

Step 2: Conduct Resource Adequacy Modeling

Once the policymaker sets a resource adequacy target, a resource adequacy model can predict whether a region is achieving it (and will continue to do so). Traditionally, modeling was limited to examining whether demand would exceed supply during one or a few peak load hours. But the energy transition, combined with extreme weather from climate change, requires planners to rethink prevailing resource adequacy modeling techniques. For most systems, it is now important to model all 8,760 hours of the year, in chronological order, to accurately capture the risk of load shed.

Along with improving models' temporal resolution, it has become important to make more sophisticated assumptions about modeling inputs. In particular, it has become critical to capture how supply and demand have become more dependent on the weather, which, in turn, has become more extreme. In general, a best practice is to use the Monte Carlo method, and run many (on the order of hundreds or thousands) simulations of grid operations, allowing the model to randomly pull from a distribution of possible values for every input.[70] Additionally, best practices exist for curating the data for each input and their interdependencies, such as representing the relationship between the weather and thermal outages.[71]

Temporal Scope

Historically, resource adequacy modeling focused on the likelihood that supply would exceed demand during one (or a few) top demand hours, ignoring the risk of inadequate supply during the rest of the year.[72] This simplification was more plausible when the grid was dominated by dispatchable resources with relatively predicable outputs.[73]

Now, with the increased penetration of wind and solar, periods of resource adequacy risk have shifted from peak demand to "net peak" demand, defined as load minus energy from non-dispatchable resources.[74] In this new reality, the system is most likely to lack sufficient supply when there is high demand unserved by wind or solar. And, just as weather dictates the performance of these variable resources, it also affects outages at thermal generators (e.g., interruptions of natural gas supply) and load (not just by influencing customers' demand, but also by altering

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70 See Inputs, below, for a more detailed description of the Monte Carlo method.

71 For example, cold winter snaps have historically yielded correlated outages of thermal generators. Nick Wintermantel & Nick Simmons, Astrapé Consulting 8 (2022), https://perma.cc/6D7Y-QCZ2. Similarly, extreme hot weather can require both thermal and nuclear units to cease operations, if the unit can no longer use intake water bodies for cooling. *E.g., High French River Temperatures to Hit Nuclear Production Next Week*, Reuters (June 20, 2025), https://www.reuters.com/business/energy/high-french-river-temperatures-hit-nuclear-production-next-week-2025-06-20.

72 Juan Pablo Carvallo et al., *supra* note 8, at 9; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2.

73 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 2; Juan Pablo Carvallo et al., *supra* note 8, at 1, 27.

74 Jill Moraski et al., Clean Air Task Force, Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways 21 (2025), https://perma.cc/3A39-FQLW.

behind-the-meter generation that typically provides "negative" load).[75] Given this confluence of variables, the best practice is now to examine all 8,760 hours of the year when evaluating the likelihood and expected characteristics of shortfalls.[76]

The increased prevalence of energy-limited resources like battery storage and demand response have similarly complicated more traditional resource adequacy modeling assumptions. Battery storage's ability to avoid a resource adequacy shortfall will depend on its state of charge.[77] For example, a battery could have sufficient energy to prevent a shortfall in the morning and then, if it has no opportunity to recharge, be empty for a second event that same afternoon. Similarly, demand response participants have only a limited willingness to curtail or shift their demand; activating the program degrades its later effectiveness.[78] Accordingly, the best practice for resource adequacy modeling is to not just to consider all 8,760 hours, but to do so sequentially, capturing how storage and demand response used in one hour can affect their subsequent availability.[79]

Inputs

To keep pace with the many uncertainties of contemporary resource adequacy analysis, planners have shifted to probabilistic modeling approaches like the Monte Carlo method.[80] Under this best practice, rather than assessing resource adequacy using specific expected values for each input, the user provides the model with a probability distribution for different inputs, and the model randomly samples from those distributions across hundreds or thousands of simulated scenarios.[81] The model will draw the load for each hour, along with potentially correlated variable generation, thermal resource availability, and transmission outages.[82]

While the Monte Carlo method can yield more accurate resource adequacy estimates than simpler methods, its accuracy depends on the user-provided probability distributions, as well as accurate specification of key interdependencies.[83] For weather data, the current best practice is to use as many years as are available, with hourly resolution and geographic granularity.[84] And, especially when forecasting longer-term resource adequacy, it has become important to account

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75 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

76 Juan Pablo Carvallo et al., *supra* note 8, at 27; Standard Authorization Request (SAR) Form, N. Am. Elec. Reliability Corp. at 2, https://perma.cc/Q8AU-9YWW.

77 Energy Sys. Integration Grp., Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation 11 (2023), https://perma.cc/4ETD-JQK2.

78 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 55–56.

79 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 9; Juan Pablo Carvallo et al., *supra* note 8, at 9; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 44.

80 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 9.

81 *Id.* at 10.

82 Juan Pablo Carvallo et al., *supra* note 8, at 13.

83 Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 12.

84 Juan Pablo Carvallo et al., *supra* note 8, at 30.

for climate change projections,[85] including the increasing severity of extreme events.[86]

For load, the best practice is to capture its relationship to the weather, and to add a probabilistically determined amount of distributed generation as negative load.[87] Similarly, for generation, the best practice is to derive the relationship between weather and its output, while also accounting for how technological improvements will improve production profiles,[88] along with the possibility of other types of common mode failures.[89]

Other important considerations include realistic assumptions about electricity imports from neighboring regions (e.g., probabilistically modeling neighbors' operations during tight periods),[90] intraregional transmission constraints,[91] the impact of probabilistic intraregional transmission failures,[92] and for when the model decides that an outage has been triggered.[93]

Additionally, for forecasting longer-term resource adequacy, modelers need to make assumptions about which resources retire and come online. These assumptions will have a large bearing on model outputs. For retirements, modelers should include announced retirements while also forecasting unannounced retirements by accounting for likely retirements due to federal and state policy, age-based retirements, and retirements driven by economics.[94] For near-term new generation and storage, modelers should consider projects that have cleared or will soon clear the interconnection queue, along with expected build times.[95] To anticipate later-term resource additions, modelers should consider resource costs and trajectories, regulatory incentives and barriers, and other relevant drivers. As with other inputs, modelers can implement retirements and additions through a distribution of probabilities, rather than strict assumptions about what will occur.[96]

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85 *Id.*

86 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 22.

87 Juan Pablo Carvallo et al., *supra* note 8, at 31.

88 *Id.* at 32.

89 Elec. Power Rsch. Inst., Modeling New and Existing Technologies and System Components in Resource Adequacy 17–18 (2023), https://perma.cc/3CWR-G5LM; Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 37–38; *How MISO Utilizes PLEXOS for Enhanced Resource Adequacy*, Energy Exemplar (Oct. 9, 2024), https://perma.cc/VQY8-WAVX.

90 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 31; Adria E. Brooks et al., Grid Strategies LLC, Resource Adequacy Value of Interregional Transmission 31 (2025), https://perma.cc/77FQ-L94V; Sam Hostetter & Derek Stenclik, Analysis of Resource Adequacy Across the Eastern Interconnection 7, 16 (2025), https://perma.cc/LCU4-LBZF.

91 Elec. Power Rsch. Inst., Resource Adequacy Scenario Selection Guide 6, (2024), https://perma.cc/FZ5A-5G2M.

92 Juan Pablo Carvallo et al., *supra* note 8, at 13–14; Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 12.

93 Kevin Carden et al., *supra* note 50, at 7.

94 Inst. for Pol'y Integrity, Comments on Policy-Driven Retirements in the Context of Order No. 1920 at 4–6 (Oct. 18, 2024), https://perma.cc/GB4R-X55D.

95 *E.g.,* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

96 *See* Inst. for Pol'y Integrity, Comments, *supra* note 94, at 7–8.

Step 3: Accreditation

After resource adequacy modeling, the next step is to derive how much credit each resource deserves for its contribution towards the system's resource adequacy—a process called "accreditation." A resource's accreditation, typically expressed as a fraction of its nameplate capacity, captures the resource's estimated availability during the periods when resource adequacy is most strained.[97]

If a planner is interested in determining only whether a system is achieving its resource adequacy target, this step is unnecessary because Step 2 will accomplish that.[98] Nor is this step strictly necessary to determine how the retirement of any particular resource would affect reaching the resource adequacy target; a planner can accomplish that by re-running Step 2 without the resource included.

But, as explained further in Step 4, accreditation is important to calculate a region's *reference reserve margin*, i.e., the resource adequacy cushion that, when obtained, suggests that the system will achieve its resource adequacy target. Accreditation is also valuable because, once a planner calculates the reference margin level, having these accreditation values can allow a policymaker to quickly estimate how the retirement or addition of particular resources would affect maintaining that margin, without needing to re-run the resource adequacy modeling. This kind of analysis could satisfy the EO's call for a protocol to "identify which generation resources within a region are critical to system reliability."[99]

Historically, planners accredited thermal resources at their full nameplate capacity—reflecting an assumption that they could always generate at maximum capacity during the moments of greatest resource adequacy risk—or accredited them based on their nameplate capacity discounted by their average forced outage rate.[100] Variable resources have often been accredited based on their historical performance during peak load hours.[101]

With the energy transition and climate change, however, the best practice is to derive a resource's accreditation from the resource adequacy modeling described in Step 2 using a probabilistic

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97 An Pham et al., Nat'l Renewable Energy Lab'y, Average and Marginal Capacity Credit Values of Renewable Energy and Battery Storage in the United States Power System 5 (2024) (using the equivalent phrase "capacity credit"). These times have become increasingly decoupled with peak load events. Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 4.

98 Juan Pablo Carvallo et al., *supra* note 8, at 36 ("Capacity accreditation is not inherent to resource adequacy assessments . . . ."); Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at vii ("While resource adequacy analysis assesses whether there are enough resources to serve load across the system, capacity accreditation measures the contribution of individual resources toward meeting that goal, both in terms of capacity and energy.").

99 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15522 (Apr. 14, 2025).

100 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 9, 37; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 5.

101 Juan Pablo Carvallo et al., *supra* note 8, at 36.

method.[102] Probabilistic methods like Effective Load Carrying Capability (ELCC) analyze how slight changes in the modeled resource inputs would affect resource adequacy outcomes.[103] They typically work by adding more of the studied resource to the model, beyond what exists in the base case, and then adding load until the model's base case resource adequacy outcome is restored.[104]

The benefit of probabilistic approaches like ELCC is that, when the modeling inputs from Step 2 are well-curated, the resulting accreditations will more accurately reflect a resource's contribution to resource adequacy during the true risk periods.[105] Additionally, these methods consider a wide range of possible futures, including the possibility of tail events, rather than assuming the future will resemble the past.[106]

The best practice is to apply these ELCC-style methodologies to both variable and thermal resources, storage, and transmission.[107] It is important to treat all resource types equally because capacity accreditation provides a technology-agnostic way of comparing resources' resource adequacy contributions.[108] That purpose is compromised when the resource adequacy value of variable resources is reduced to account for myriad factors affecting their output, without parallel reductions capturing thermal resources' weather dependency and common mode outages.[109] With increased saturation of natural gas resources—which are susceptible to fuel disruptions and extreme weather—it is more important than ever to accurately account for thermal generations' winter risks, especially the risk that a significant amount of thermal capacity will become unavailable at once.[110] Probabilistic methods are ideal for understanding the effect of these risks, including tail risks, in light of the complicated interdependencies of all the factors that dictate the timing of resource adequacy shortfalls.[111]

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102 *Id.* at 36–37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning 24–27 (2011), https://perma.cc/294F-25KU.

103 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 13.

104 *Id.*

105 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 12–14; Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 15; Christoph Graf et al., *supra* note 57, at 30. As explained in Step 2 above, these risk periods are becoming harder to predict due to weather's increased influence on supply and demand, and because of increased energy-limited resources in the generation mix.

106 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 14.

107 Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 28; Adria E. Brooks et al., *supra* note 90, at 31.

108 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 32, 37.

109 *Id.* at 37–38.

110 Elec. Power Rsch. Inst., Resource Adequacy Gap Assessment, *supra* note 40, at 24; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 40–41; Elec. Power Rsch. Inst., Resource Adequacy Assessment Tool Guide, *supra* note 31, at 30; Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 27.

111 *See* Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 11 ("Increasingly, periods of risk are driven by correlation among many components that are often weather-related, including high load, low renewable resource availability, drought, and correlated outages and fuel supply disruptions from the fossil fuel generators."); N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 91 ("If resource performance were to occur at the levels expected during average winter days, the system should be able to serve these high loads. However, resource performance from thermal resources on very cold days, especially natural gas resources, is more likely to be poor. This, coupled with poor performance from solar

Step 4: Calculating the Reference Margin Level and the Reserve Margin

Using Step 2's resource adequacy modeling and Step 3's accreditations, a planner can assess whether a region's fleet would achieve its appropriate reference margin level.[112] The reference margin level typically expresses the amount of accredited capacity that a region would need to achieve its resource adequacy target. The planner will conduct resource adequacy modeling, adding or subtracting additional capacity or load until the system reaches the resource adequacy target. The reference margin level is the sum of the accredited capacity needed to achieve the target.

Once the planner derives the reference margin level (how much total accredited capacity the system requires), it is also possible to answer whether any particular resource is critical to achieving the margin. To check this, the planner would subtract the accredited capacity of the resource in question from the total accredited capacity of the region, and check whether the difference exceeds the reference margin level.

Reference Margin Levels

Historically, reference margin levels were—and, in some places, continue to be—resource adequacy targets in themselves (e.g., a target of accredited capacity that is 15% above peak load).[113] But setting a target framed entirely around the summed accredited capacity, even when informed by years of operating experience at different margin levels, yields a target that does not explicitly aim to achieve any particular outcome.[114] As explained in Step 1, targets are more typically expressed in terms of outcomes: the frequency, duration, and/or magnitude of shortfalls.

Yet the idea of a reference margin level has persisted, as planners often convert their outcome-focused targets into the equivalent reference margin levels.[115] For example, a region might have a 0.1 LOLE target and then determine that the 0.1 LOLE target is achieved when the region's installed capacity has an accreditation of at least 15% above peak load.[116] The same type of translation is possible for targets set using other metrics, like EUE or LOLH.[117]

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resources, results in very low total electricity supply and causes loss-of-load events in the ProbA analysis. The winter load-loss events tend to occur during morning and evening demand peaks and coincide with poor thermal performance and poor solar performance.").

112 This is also commonly referred to as a planning reserve margin, connoting that it includes resources that are in reserve and only be dispatched in highly constrained scenarios.

113 Elec. Power Rsch. Inst., Resource Adequacy Philosophy, *supra* note 21, at 24; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 8–9.

114 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 5–6; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 29–30.

115 Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 7; Juan Pablo Carvallo et al., *supra* note 8, at 37; N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 1.

116 Juan Pablo Carvallo et al., *supra* note 8, at 28.

117 N. Am. Elec. Reliability Corp. & Nat'l Acad. of Eng'g, *supra* note 9, at 15; Juan Pablo Carvallo et al., *supra* note 8, at 29.

Given how resource adequacy risk has evolved, however, the best practice is to derive the reference margin level using the probabilistic resource adequacy modeling from Step 2 (itself conducted in accordance with best practices).[118] Doing this helps to ensure that the margin is calculated to comprehensively reflect year-round risks. Indeed, when resource adequacy risk shifts beyond peak load hours, the amount of accredited capacity necessary to achieve the resource adequacy target can become *lower* than peak load—because resources' accreditations will be based on their outputs during moments of greatest risk, which may be lower than their outputs at peak load.[119] Accordingly, calculating a reference margin level that matches accredited capacity to peak load would overestimate the necessary margin.

While there are multiple plausible ways to use probabilistic resource adequacy modeling to convert the resource adequacy target to a reference margin level, the general approach depends on whether the modeling reveals that the system is exactly achieving the target, underachieving it, or overachieving it. For the rare case in which the system happens to be exactly achieving the resource adequacy target, then the sum of the total accredited capacity installed on the system equals the reference margin level. It can be expressed as MW of accredited capacity, or in reference to some other amount, like a percentage of peak load.[120]

It is more likely, however, that the system is either above or below the resource adequacy target. In these instances, it is common to add or subtract accredited capacity in the model until the system achieves the target.[121] Then, the reference margin level will be the amount of accredited capacity on the modeled system when the target is achieved, again expressed as a quantity of MWs or as a percentage of peak load.

Effect of Particular Resources

Once the reference margin level and accreditation values have been calculated, it becomes possible to test how the exit (or entry) of a particular resource would affect the region's resource adequacy.

An example is useful in understanding how. Imagine that the reference margin level for a region is 25 GW, and its resource mix has 26 GW of accredited capacity. As is, the region would be exceeding its reference margin level by 1 GW. If any resource with an accreditation greater than 1 GW were to exit the grid, that would cause the actual reserve margin to dip below the reference margin level. Because the reference margin level was calculated following Steps 1–3,

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118 Elec. Power Rsch. Inst., Resource Adequacy for a Decarbonized Future, *supra* note 15, at 6, 11; Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 11.

119 Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 18.

120 *Id.*; N. Am. Elec. Reliability Corp., Methods to Model and Calculate Capacity Contributions, *supra* note 102, at 6.

121 Nat'l Ass'n of Regul. Util. Comm'rs, *supra* note 12, at 95. *See also, e.g.*, MISO, Planning Year 2025–2026 Loss of Load Expectation Study Report 34–35, https://perma.cc/4VV5-4FHU; Western Power Pool, Western Resource Adequacy Program, 102 Forward Showing Reliability Metrics 14 (2024), https://perma.cc/7A6Q-A96E; NYISO, 2024 Reliability Needs Assessment 44 (2024), https://perma.cc/LD5E-RMV9; IESO, Annual Planning Outlook: Resource Adequacy and Energy Assessments Methodology 19 (2024), https://perma.cc/26N7-QC5J.

this dip would indicate that the region can no longer be expected to achieve the resource adequacy target (e.g., 0.1 LOLE) underlying the 25 GW reference margin level. In contrast, any resource with an accredited capacity of 1 GW or less could retire without causing the system to violate its resource adequacy target.

Importantly, this technique for evaluating individual resources' impact works only for relatively small changes to the system, such as the exit or entry of one or a few plants. When larger changes happen in the region's resource composition, the new mix will itself affect resources' accreditation values, because these values inherently depend on the entire fleet composition.[122] To calculate the resource adequacy effect of major changes to the fleet (e.g., the retirement of half of the coal capacity in a region), it would be necessary to re-run the modeling from Step 2 with different inputs.

Having reviewed resource adequacy terms, methodologies, and best practices, Part 2 next uses this understanding to discuss DOE's recent resource adequacy modeling endeavor.

[122] Energy Sys. Integration Grp., Ensuring Efficient Reliability, *supra* note 77, at 30.

Part 2: DOE's *Resource Adequacy Report*

On July 7, 2025, DOE published its *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid* (DOE Study), responding to the EO's request for a "uniform methodology to identify at-risk region(s) and guide reliability interventions."[123] The report does not fulfill the EO's separate request for a "a protocol to identify which generation resources within a region are critical to system reliability."[124]

The DOE Study generally examines the resource adequacy of two time periods: today and 2030. According to the study, today, only ERCOT currently fails to achieve DOE's selected resource adequacy targets.[125] Under DOE's assumptions about load growth (including load growth from data centers), resource additions, and retirements, its modeling shows that all transmission planning regions will be resource inadequate in 2030 except ISO-NE and NYISO.[126] When reporting that a region is or would be resource inadequate, DOE sometimes calculates the amount of perfect capacity that could restore the region to resource adequacy.[127]

The DOE Study borrows heavily from NERC's recent Interregional Transfer Capability Study, which analyzed interregional transmission capacity and evaluated how additional interregional capacity could improve resource adequacy.[128] In contrast to NERC's Interregional Transfer Capability Study, the DOE Study does not consider how shortfalls could be mitigated through additional interregional transmission, which can be an alternative to new generation.[129]

Building on Part 1's discussion of how a resource adequacy model's metrics, values, and input assumptions drive its results, this Part evaluates DOE's resource adequacy methodology, including its input choices for load growth, resource additions, and retirements. At each step, it discusses the assumptions embedded in DOE's modeling choices, and reviews why those assumptions provide a weak basis for commanding specific, aging resources to continue serving load at consumers' expense and outside of existing market structures.

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123 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at vi.

124 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

125 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7.

126 *Id.* at 8.

127 *Id.* at 5. The exact meaning of these perfect capacity quantities is unclear due to contradictions within the DOE Study. At times, DOE explains that these are the perfect capacity quantities that restore the system to 0.002% while assuming projected retirements. *Id.* At other points, though, DOE states that these quantities assume no retirements. *Id.* at 9.

128 *Id.* at 2; N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study vi, ix (2024), https://perma.cc/U7M3-L56J.

129 *See generally* Adria E. Brooks et al., *supra* note 90.

Resource Adequacy Targets

The DOE Study uses a multi-metric resource adequacy target of 2.4 LOLH and 0.002% normalized unserved energy (NUSE), which is the deterministic equivalent to NEUE.[130] DOE's decision to use a multi-metric target aligns with best practices, and its decision to use LOLH and NEUE together is reasonable. But DOE's value selections for these metrics are problematic.

For LOLH, DOE indicated that it picked 2.4 because that value "translates into one day of lost load in ten years," i.e., the traditional 0.1 LOLE standard.[131] This decision does not align with best practices for two reasons. First, it seeks to unquestioningly replicate the already arbitrary 0.1 LOLE standard (which merely captures the level of resource adequacy that happened to exist in the 1940s).[132] DOE's choice thus does not reflect any meaningful cost-benefit analysis.

Second, DOE's conversion of 0.1 LOLE to 2.4 LOLH is inaccurate.[133] A region with 0.1 LOLE will experience only one day with an outage—of any length—across ten years, which will be 24 hours in only the most extreme case. A region with 2.4 LOLH will have 24 hours of outages across the decade, across any combination of hours. DOE's selection of 2.4 LOLH metric would therefore, in the vast majority of cases, permit a greater duration and frequency of outages.[134] Although this 2.4 LOLH target might indicate that, all else being equal, DOE's methodology is too permissive, DOE's inputs and assumptions likely dominate its analysis and lead DOE to overestimate potential shortfalls.

Turning to NUSE, DOE reports that it selected 0.002% because NERC uses that same value in its long-term resource adequacy assessments.[135] But, as discussed in Part 2, NERC adopted that value from Australia without any consideration of how the costs and benefits of resource adequacy differ in the U.S. context.[136] In contrast, DOE previously used 0.001% in the National Transmission Planning Study.[137]

Moreover, contrary to best practices, for both LOLH and NUSE, DOE imposes the same resource adequacy target across the entire continental United States, without considering regional differences. As noted in Part 1, when it comes to averting outages, regions face different costs and benefits with regard to resource adequacy and thus different socially optimal levels of resource adequacy.

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130 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4, 14 ("This study does not employ common probabilistic industry metrics such as EUE or LOLE due to their reliance on probabilistic modeling. Instead, deterministic equivalents are used.").

131 *Id.* at 4.

132 Kevin Carden et al., *supra* note 50, at 2; Energy Sys. Integration Grp., New Resource Adequacy Criteria, *supra* note 6, at 6.

133 Juan Pablo Carvallo et al., *supra* note 8, at 11 ("The LOLE is typically used as a target setting metric and has historically taken a value of 1 event-day in 10 years, commonly (and incorrectly) interpreted as 2.4 hours per year.").

134 Gord Stephen et al., *supra* note 15, at 3, https://perma.cc/A9DJ-C3B5.

135 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4 n.10.

136 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 141.

137 U.S. Dep't of Energy, National Transmission Planning Study: Chapter 2: Long-Term U.S. Transmission Planning Scenarios 4, 82 (2024), https://perma.cc/R8RA-23E2.

Finally, at times, the DOE Study appears to struggle with the very meaning of a resource adequacy standard: It questions both PJM's and SPP's resource adequacy, even though each satisfies the metrics DOE's itself picked for its analysis. For PJM in particular, DOE notes that the region currently satisfies both prongs of the resource adequacy metric, but not for the particular weather year that includes Winter Storm Elliot.[138] Seemingly for this reason, DOE concludes that PJM needs 2.4 GW of additional perfect capacity to be resource adequate now.[139] But DOE's resource adequacy targets are, in DOE's own words, "average indicators" to be achieved across all modeled scenarios, not a requirement that must be achieved in each and every scenario.[140] PJM is resource adequate today according to DOE's targets.

Of course, as discussed in Part 1, it may be reasonable for a system planner to set a resource adequacy target that depends, in part, on each region's performance during tail risks. But DOE has not done so here.

Resource Adequacy Modeling

DOE's resource adequacy modeling is inconsistent with best practices. DOE's high-level decisions about the study's overall modeling approach and data input decisions both diverge from the best practices described in Part 1.

Deterministic Model

While the DOE Study appropriately examines all 8,760 hours of the year in chronological order,[141] DOE departs from best practices by using deterministic modeling rather than a probabilistic approach (like the Monte Carlo method), perhaps because of the EO's relatively short timeline.[142] Rather than randomly sampling probability distributions for each input to construct hundreds or thousands of plausible scenarios, DOE "evaluates whether a power system has sufficient resources . . . under a pre-defined set of conditions which correspond to the past few years of real-world events."[143] DOE uses twelve years of data (2007–2013 and 2019–2023) for weather, load, and generation.[144]

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138 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 7, 9, 27.

139 *Id.* at 9.

140 *Id.* at 7.

141 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10, 12–13.

142 *Id.* at 2. The EO provided an extremely accelerated deadline of 90-days for DOE to produce results. *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025). The DOE Study itself provides additional evidence for this conclusion, with its acknowledgement that "[p]robabilistic approaches incorporate data and advanced modeling techniques to represent uncertainty" but "require more computing power." U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.

143 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 10.

144 *Id.* at 11. While DOE uses historical data for the years 2019–2023, it uses "synthetic" data for 2007–2013. *Id.* "The synthetic approach used historical weather data to estimate load and resource availability if those same weather conditions were to occur again in the future. The historic approach used historical measured data for load, as well as wind and solar resource output, from recent years and scaled it appropriately to represent future conditions." N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 74.

By examining whether regions would be resource adequate only under conditions that resemble the recent past, DOE's study does not sufficiently account for uncertainty. Indeed, in the Interregional Transfer Capability Study, from which DOE borrowed, NERC itself explains the limitations of this same deterministic approach and same data: Some regions may look resource adequate because they happened to do well during the twelve years of data, while others look resource inadequate but be unlikely to perform as poorly in the future.[145] Addressing the deterministic vs. probabilistic distinction, NERC cautions that, because a "[p]robabilistic resource adequacy analysis was not conducted[,] . . . . the [Interregional Transfer Capability Study] should not be considered a North American resource adequacy assessment."[146]

DOE grounds its use of a deterministic model in "transparency" and an interest in "model[ing] detailed historic system conditions."[147] Neither is a reason to step away from best practices: DOE could document a probabilistic approach in a transparent way, and relying on a small sample of historic years is less accurate than a probabilistic approach. Given the high stakes associated with resource adequacy planning, any future DOE resource adequacy assessment should prioritize accuracy over expediency.

Outage Threshold

Another modeling choice is the threshold for determining when a shortfall event has occurred. DOE projects a shortfall if "the remaining capacity after transmission and demand response falls below the 6 percent or 3 percent needed for error forecasting and ancillary services, depending on the scenario."[148] This choice means that DOE identifies shortfall events in the hours when, after exhausting imports and demand response, a region's excess energy falls below 6% or 3% of hourly load—but it is not clear when DOE uses 6% versus 3%. DOE states that more details are available in a section of the study's appendix entitled "Outputs," but, as of publication of this report, no such section appears to be available.[149]

NERC uses a 3% threshold in its Interregional Transfer Capability Study, using 6% only in a sensitivity analysis.[150] According to NERC, the 3% value "was established based on an evaluation of average reserve requirements where load shed may occur" and reflects how "a Balancing Authority will continue to hold reserves even if involuntary load shed is underway to safeguard the system from cascading or widespread outages."[151] It is impossible to tell from the DOE Study when DOE used 6% versus 3%, but the fact that DOE listed 6% first may suggest that 6% was not limited to a sensitivity analysis.

If DOE's model instead identifies shortage events even when a region still has 6% of load available as spare capacity, then DOE's results depart from NERC's practice and may overstate

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145 *Id.* at 138.
146 *Id.* at 4.
147 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2 n.2.
148 *Id.* at 12.
149 *Id.*
150 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 84.
151 *Id.* at 91 n.90, 85.

the extent of expected outages. In NERC's Interregional Transfer Capability Study, this change alone *significantly* altered the existence and extent of predicted outages in many regions, such as producing a 690% increase in the size of the maximum outage event in SERC-Florida.[152] Under the 6% sensitivity, NERC also recommended 58 GW of transmission additions to address resource adequacy instead of 35 GW, illustrating the sizable influence of shifting this assumption from 3% to 6%.[153]

Inputs

DOE's prediction that most regions will experience resource inadequacy by 2030 depends heavily on its assumptions about resource additions, retirements, load growth, and interregional imports. In each instance, DOE makes choices that raise significant questions about the validity of its modeling results.

Additions

DOE assumes that the only resource additions by 2030 will be those NERC currently categorizes as "Tier 1."[154] To be a Tier 1 resource, the resource must have achieved at least one milestone from a NERC list that signifies the unit is "very mature in the development pipeline."[155] This assumption is very conservative: The study itself admits that "[t]his results in minimal capacity additions beyond 2026."[156] In other words, DOE's finding of widespread resource inadequacy in 2030 rests on the assumption that very little will be built from 2027–2030. For example, NERC identifies 17,047 MW of Tier 1 resources slated to come online in PJM throughout 2025 and 2026, but only 1,108 MW from 2027–2030.[157]

The drop-off in Tier 1 resources after 2026 is not due to a shortage of projects in development, but rather because NERC currently classifies much of the capacity that will come online between 2027 and 2030 as "Tier 2."[158] Tier 2 resources occupy a wide range of positions in the interconnection queue, from the earliest stages (e.g., those having completed a feasibility study) to the very end

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152 *Id.* at 105 tbl.8.4

153 *Id.*

154 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 4.

155 *Id.* at A-5. More specifically, the resource must have finished construction, be under construction, have a signed/approved interconnection service agreement, have a signed/approved power purchase agreement, have a signed/approved construction service agreement, have a signed/approved wholesale market participant agreement, or (if it is in the footprint of a vertically integrated utility) be included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement. N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 137.

156 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at A-5. *See also* Ric O'Connell, *GridLab Analysis: Department of Energy Resource Adequacy Report*, GridLab (July 11, 2025), https://perma.cc/B3GC-T7GA ("The report assumes just 22 GW of new 'firm' capacity (narrowly defined as gas) is added which is based on NERC LTRA 'Tier 1' – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030**.") (bolded text in original).

157 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 89.

158 *See id.* at 137.

of the process (e.g., those that have requested an interconnection service agreement).[159]

In recent years, the median project has taken approximately 55 months (4.58 years) to go from entering the queue to commercial operation.[160] Extrapolating from this historical trend reveals that a large number of Tier 2 resources will likely be operating by 2030. DOE should have anticipated some of them in the 2030 resource mix, and it departed from best practices by excluding all Tier 2 resources.[161] To do this forecasting accurately, DOE should have examined historical statistics of interconnection queue time by region, resource type, and resource size, along with differentiated queue withdrawal rates, estimating Tier 2 resource additions for each region.[162]

And applying historical statistics for time spent in a region's interconnection queue would itself be a conservative methodology for DOE to use, as FERC Order 2023 and related regional interconnection queue updates are set to speed up waiting times.[163] For example, the DOE Study found a 10.5 GW resource adequacy deficit for PJM in 2030 but failed to consider the almost 12 GW of nameplate capacity—mostly gas—that PJM is fast-tracking through its Reliability Resource Initiative.[164] PJM expects that 90% of this capacity will be online by 2030.[165] PJM is simultaneously pursuing other resource adequacy interventions, including a FERC-approved change to surplus interconnection service (to allow new generators to come online faster by taking advantage of underutilized transmission capacity),[166] and a FERC-pending proposal to expedite the process to transfer capacity interconnection rights from retiring generators to new resources.[167]

Finally, recently "retired" resources represent another potential source of fast additions.[168]

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159 *Id.*

160 Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 41 (2024), https://perma.cc/5DE4-XNK6.

161 *See* N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 23 fig.2.

162 *See generally* Joseph Rand et al., Lawrence Berkeley Nat'l Lab'y, Queued Up: 2024 Edition: Characteristics of Power Plants Seeking Transmission Interconnection As of the End of 2023 (2024), https://perma.cc/5DE4-XNK6.

163 *Improvements to Generator Interconnection Procedures and Agreements*, 184 FERC ¶ 61,054 (2023).

164 Donnie Bielak, PJM, Reliability Resource Initiative: Additional Summaries 2 (2025), https://perma.cc/Y2AB-3CEM; Donnie Bielak, PJM, Reliability Resource Initiative: Results Summary 6 (2025), https://perma.cc/MYQ8-Y53G. *See also* Ric O'Connell, *supra* note 156 ("The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.").

165 *PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth*, PJM Inside Lines (May 2, 2025), https://perma.cc/8EW2-G2XZ.

166 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,083 (2025).

167 Proposed Revisions to PJM's Open Access Transmission Tariff, PJM, Docket No. ER25-____-000 (Jan. 31, 2025), https://perma.cc/J9T3-MCGL.

168 *E.g.*, Francisco "A.J." Camacho & Daviel Schulman, *Mothballed Nuclear Plant on Brink of Revival*, EnergyWire (July 15, 2025), https://subscriber.politicopro.com/article/eenews/2025/07/15/mothablled-nuclear-plant-on-brink-of-revival-00445239.

Retirements

DOE's assumption that 104 GW of nameplate capacity will retire by 2030 likely overestimates retirements.[169] This number includes both "confirmed" retirements—resources that have notified their system operators of their impending retirements and begun the retirement process—and "announced" retirements—which are publicly stated but not officially noticed.[170] These data come from NERC's Long-Term Reliability Assessment 2024 model.[171] In turn, NERC receives reports of confirmed retirements directly from each region, while announced retirements come from multiple sources, including Energy Information Agency Form 860 data, trade press, and utility integrated resource plans.[172]

These data likely overestimate retirements.[173] First, the economics of energy production have changed since 2024. The combined effect of new demand from data centers and the elimination of federal tax credits for new wind and solar resources improves the financial outlook for thermal resources.[174] Second, federal environmental regulations that would have required thermal resources to make investments reducing their pollution or else retire were projected to result in significant retirements before 2030.[175] But the Trump Administration has begun to rescind or reexamine these rules, which could cause resources to delay their retirements.[176]

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169 *See* U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

170 *Id.* at 12.

171 *Id.*

172 N. Am. Elec. Reliability Corp., 2024 Long-Term Reliability Assessment, *supra* note 51, at 28 n.19.

173 Ric O'Connell, *supra* note 156 ("The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.") (bolded text in original).

174 Aurora Energy Research, Impact of Reform to Clean Energy Tax Credits on Investment, Jobs and Consumer Bills 10 (2025), https://perma.cc/VHR5-UEGP; ("Most demand is made up through more production from existing plants (35%), meaning these plants are running for longer hours and/or at higher output levels. Some projects that retired in the base case scenario see longer lifetimes in Tax Credit Removal scenario because of more favorable economics due to clean energy decline (making up 17% of lost generation), and the rest is made up for by new build thermal plants (29%)."); Energy Innovation Pol'y & Tech. LLC, Federal Clean Energy Tax Credits Make Energy More Affordable—A Meta-Analysis (2025) https://perma.cc/QH2E-7PLL ("The research is clear—repealing technology-neutral energy tax credits would raise annual energy bills up to $140–$220 per year nationally, and over $500 per year in some states."). *See also* Ethan Howland, *PJM Capacity Prices Hit Record Highs, Sending Build Signal to Generators*, Utility Dive (July 31, 2024), https://perma.cc/UC6U-QHYT ("Prices in the PJM Interconnection's latest capacity auction hit record highs, which should provide incentives for power plant companies to build new generating resources and keep existing ones operating, according to the grid operator."); Ethan Howland, *MISO Summer Capacity Prices Jump to $666.50/MW-day as Power Supplies Shrink*, Utility Dive (Apr. 29, 2025), https://perma.cc/A6S5-4A4U ("Capacity prices for the upcoming summer season jumped to $666.50/MW-day from $30/MW-day last year across the Midcontinent Independent System Operator's footprint—driven in part by declining surplus capacity, according to the results of its latest planning resource auction released Monday.").

175 PJM, Energy Transition in PJM: Resource Retirements, Replacements & Risks 8 (2023), https://perma.cc/7J3A-FL8U.

176 *EPA Launches Biggest Deregulatory Action in U.S. History*, EPA (Mar. 12, 2025), https://perma.cc/55MN-2SUB.

Load

The DOE Study assumes 50 GW of growth in data center load and 51 GW of additional non-data center load.[177] DOE does not account for the possibility that this data center load could be flexible, even as one study suggests that 76 GW of additional data center load could be accommodated today if it could be curtailed only 0.25% of the time, and relevant corporations have confirmed flexibility potential.[178]

In June 2025, Texas enacted a law that allows ERCOT to curtail certain new loads over 75 MW during emergencies.[179] DOE assumes an additional 8 GW of data center load in ERCOT by 2030 and finds a reliability shortfall of 10.5 GW (which is likely an overestimate for the reasons discussed elsewhere in this Part, including how this 10.5 GW brings ERCOT to 0.0008% NUSE instead of 0.002% NUSE).[180] Accordingly, Texas's new law could go a long way towards avoiding the DOE-identified resource adequacy problem. Other regions like PJM are considering strategies to soften the resource adequacy impact of data centers, including ways to better encourage their participation in demand response programs.[181] DOE should have considered the possibility that some of the projected data center load would be flexible, especially in ERCOT.

Additionally, how DOE chose to distribute the projected 50 GW of data center load across regions is questionable. The DOE Study explains it used state-level growth ratios to perform this allocation.[182] But it is unlikely that all the computing demand needs to be processed close to load centers (i.e., proportional to a region's current electric load). In fact, some computing demand

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177 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 2–3.

178 Tyler H. Norris et al., Nicholas Inst. for Energy, Env't & Sustainability, Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems 2 (2025), https://perma.cc/6693-3HZU; *EPRI Launches Initiative to Enhance Data Center Flexibility and Grid Reliability,* Elec. Power Rsch. Inst. (Oct. 29, 2024), https://perma.cc/75LY-PSP5 ("Led by EPRI, DCFlex will coordinate real-world demonstrations of flexibility in a variety of existing and planned data centers and electricity markets, creating reference architectures and providing shared learnings to enable broader adoption of flexible operations that benefit all electricity consumers. Specifically, DCFlex will establish five to ten flexibility hubs, demonstrating innovative data center and power supplier strategies that enable operational and deployment flexibility, streamline grid integration, and transition backup power solutions to grid assets. Demonstration deployment will begin in the first half of 2025, and testing could run through 2027."); Anuja Ratnayake, *Unlocking AI Potential with Data Center Flexibility*, EnergyCentral (June 12, 2025), https://www.energycentral.com/intelligent-utility/post/unlocking-ai-potential-with-data-center-flexibility-PtPoXIAuRMzs5Ff ("In a preliminary test of the depth of computational flexibility possible in an AI data center, the Arizona demonstration site experienced some early success. It showcased the potential for an AI data center to provide grid relief during a peak system event—such as a hot summer day with high power demand—by temporarily and precisely ramping down its electricity consumption without compromising data center performance."). *See also* Ric O'Connell, *supra* note 156 ("It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact.").

179 S.B. No. 6 § 4, 89th Legislature (Tex. 2025) (to be enacted at Tex. Util. Code § 39.170), https://perma.cc/4Z7H-9XKQ; Brian Martucci, *Texas Law Gives Grid Operator Power to Disconnect Data Centers During Crisis*, Utility Dive (June 25, 2025), https://perma.cc/SYK3-V4XX; Waleed Aslam & Robin Hytowitz, Elec. Power Rsch. Inst., Texas SB6 Explained: Addressing Large Load Impacts (2025), https://perma.cc/QD8S-3M5C.

180 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 40.

181 Tim Horger, PJM, Large Load Additions Workshop 28 (2025), https://perma.cc/4HSN-CW4W.

182 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 17.

may be served from other regions if it will be cheaper to integrate the data center elsewhere. Given the scale of DOE's projected data center load compared to the relatively small resource adequacy shortfalls that the study identifies, these assumptions may have made the difference between whether a region achieves DOE's resource adequacy targets.[183]

Interregional Imports

The DOE Study states that it has adopted the interregional transfer capacities from NERC's Interregional Transfer Capability Study but also notes that transfers are "available up to the *minimum* total transfer capacity."[184] NERC's values describe the available transmission capacity between regions, including sub-regions of larger transmission-constrained regions like PJM, SPP, and MISO.[185] NERC provides a summer value and a winter value for each interregional interface and for each direction of flow.[186]

It is unclear what DOE means when it says that transfers are allowed up to their "minimum." If DOE picked the lesser of the summer and winter transfer capacities and applied that annually, doing so would inaccurately underestimate the amount of interregional transfer capacity.

Accreditation & Reference Margin Levels

While DOE issued its study in response to the EO's request for a "methodology to identify current and anticipated regions with reserve margins below acceptable thresholds,"[187] it does so through resource adequacy modeling, rather than by calculating accreditation values and using them to derive reference margin levels. As explained in Part 2, properly performed resource adequacy modeling is sufficient to determine whether a region is resource adequate.

In contrast, accreditations and reference margin levels are useful in combination to quickly evaluate how the loss or addition of a particular resource would affect whether a region achieves its resource adequacy target without re-running regional resource adequacy modeling. They are thus more applicable to EO Section 3(c)'s separate command to establish a "protocol to identify which generation resources within a region are critical to system reliability.[188] Thus far, DOE has not released a study implementing this provision. DOE may eventually supplement the DOE Study with additional accreditation and reference margin level analyses.

Nonetheless, while the DOE Study does not calculate accreditation values or reference margin levels, it does undertake the related exercise of evaluating how much additional perfect capacity would bring certain regions to resource adequacy.[189] (DOE calculated these perfect capacity

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183 *See id.* at 9, 17.

184 *Id.* at 18, 12, A-1 (emphasis added).

185 N. Am. Elec. Reliability Corp., Interregional Transfer Capability Study, *supra* note 128, at 7, 9–10.

186 *Id.* at 17–24.

187 Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521 (Apr. 14, 2025).

188 *Id.* at 15522.

189 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at 5.

additions for only four of the seven regions that failed to achieve 0.002% NUSE in 2030: PJM, SPP, SERC, and ERCOT—not MISO, CAISO, or West Non-CAISO.[190]) More specifically, DOE asked how much perfect capacity it would take for regions to achieve the 0.002% NUSE resource adequacy standard in 2030.[191]

If, in the future, DOE were to also calculate the accredited capacity of a region's fleet and then add the solved-for perfect capacity, it could calculate the region's reference margin level. Similarly, although DOE did not perform any perfect capacity analysis for regions that achieve 0.002% NUSE, DOE could subtract perfect capacity from the accredited capacity of the regional fleets to solve for reference margin levels. Once DOE calculates a region's reference margin, it could look at the accredited capacity of any resource to evaluate how its exit or entry would affect achievement of the reference margin level.

In calculating any reference margin levels, DOE should attend to all prongs of its multi-metric resource adequacy target. Here, DOE Study's perfect capacity exercise focuses exclusively on 0.002% NUSE. But if a region achieves 0.002% NUSE and not 2.4 LOLH, it would be resource inadequate according to the terms of this DOE Study. Separate reference margin levels may apply to each prong, and a region would be resource adequate only when the highest reference margin level is achieved.

Additionally, going forward, DOE should better prioritize accuracy in any new studies with respect to calculating a region's need for perfect capacity additions/subtractions. Critically, while DOE asserted that it added the amount of perfect capacity needed to bring each region to 0.002% NUSE, the 10.5 GW that it added to PJM actually brought it to 0.0003% NUSE; the 500 MW added to SERC brought it to 0.0002% NUSE; the 1.5 GW added to SPP brought it to 0.0002% NUSE; and the 10.5 GW added to ERCOT brought it to 0.0008% NUSE.[192] All of these values indicate significantly greater resource adequacy that 0.002% NUSE, sometimes by an order of magnitude.

While DOE explains that its perfect capacity additions were done "by hand with a limited number of iterations (15)" such that the capacity additions "should not be considered the minimum possible capacity to accomplish these targets," that approach does not appear to explain why DOE brought these regions far beyond the 0.002% NUSE target.[193] Rather, this explanation suggests that, for each of the regions, DOE could have achieved these high levels of resource adequacy using less perfect capacity than it added. Accordingly, to achieve 0.002% NUSE, DOE likely could have added much less perfect capacity than it did. Identifying resources that meet these overestimated capacity levels could result in overpaying to achieve a different resource adequacy target than selected.

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190 *Id.* at 20–42.
191 Id. at 5.
192 *Id.* at 27, 30, 32, 40.
193 *Id.* at 19.

Part 3: Next Steps

Having reviewed best practices for resource adequacy modeling and the DOE Study, this final section discusses next steps for U.S. resource adequacy policy considering the diverse actors in this space and their respective authorities.

The Federal Power Act (FPA) gives FERC, and FERC's designated "Electric Reliability Organization" (ERO), NERC, jurisdiction over and responsibility for ensuring "[e]lectric reliability" for the "bulk power system," i.e., the high-voltage transmission network and the energy that flows through it.[194] More specifically, the FPA requires NERC to "establish and enforce reliability standards," which take effect after FERC approves them.[195] Importantly, FERC can also order NERC to submit reliability standards on particular topics and can independently enforce reliability standards.[196] NERC's six regional entities (comprising the continental U.S. plus Canada) also have authority to propose reliability standards to NERC.[197]

Achieving reliability arguably requires that bulk power system be resource adequate because, as FERC explains, "[i]f resources cannot meet load, or are insufficient to provide a reserve margin above expected load, then instability, uncontrolled separation or cascading failures can result from the unanticipated loss of a system element."[198] But, although reliable grid operations depend in part on resource adequacy, the FPA does not put FERC and NERC in the driver's seat for this aspect of reliability. FERC lacks authority to *directly achieve* resource adequacy because it cannot order construction of electric generation facilities.[199] Rather, states retain their traditional authority "over facilities used for the generation of electric energy,"[200] which some exercise by requiring utilities to submit integrated resource plans describing their plans to meet future demand.[201] Other states fully or partially delegate this authority to the Regional Transmission Organizations (RTOs) that operate their regional grids, e.g., by relying on the RTOs to achieve resource adequacy through capacity markets.[202]

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194 16 U.S.C. § 824o(a).

195 16 U.S.C. § 824o(a)(2), (d). FERC does not have authority to create reliability standards directly. *See id.* at § 824o(d).

196 16 U.S.C. § 824o(d)(5), (e)(3).

197 16 U.S.C. § 824o(e)(4); *ERO Enterprise; Regional Entities,* N. Am. Elec. Reliability Corp., https://perma.cc/EQ9E-BXJW.

198 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 25 (2011). Reliable operation also encompasses a second aspect of reliability not implicated by the EO—operational reliability—which refers to "ability of the electric system to withstand sudden disturbances while avoiding cascading blackouts." Burçin Ünel & Avi Zevin, *supra* note 5, at 11.

199 16 U.S.C. § 824o(a)(3). The FPA also prohibits FERC from directing utilities to build transmission, and states retain primary siting authority for transmission. *See id.*; *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation*, 187 FERC ¶ 61,068 at P258 (2024).

200 16 U.S.C. § 824(b)(1).

201 Coley Girouard, *Understanding IRPs: How Utilities Plan for the Future*, Advanced Energy United (Aug. 11, 2015), https://perma.cc/5MDN-26QY.

202 Dena Adler & Jennifer Danis, Inst. for Pol'y Integrity, Reducing Pollution Without Sacrificing Reliability 14–16

But FERC and NERC can still play an important role for resource adequacy: FERC and NERC, through reliability standards, can ensure grid operators are proactively conducting appropriate resource adequacy assessments and analyses. In Order No. 747, FERC approved a regional reliability standard for conducting resource adequacy assessments.[203] This enforceable reliability standard requires, at a minimum, that entities within the applicable footprint conduct an annual analysis of what reserve margin would be necessary to ensure no more than 0.1 LOLE, using specific inputs like the median load forecast and accounting for important factors like fuel availability.[204] This reliability standard does not require regions to actually achieve 0.1 LOLE, only to conduct the mandated analysis.[205] A future reliability standard could require regions to instead adopt best practices comparable to those described in Part 1.

Turning to DOE, the DOE Reorganization Act put emergency grid reliability powers in DOE's hands for addressing certain emergency situations. Section 202(c) of the FPA empowers DOE, upon the finding of an emergency, to require, among any things, "such generation . . . as in its judgment will best meet the emergency and serve the public interest."[206] Section 202(c) and its implementing regulations, along with the common understanding of the word "emergency," indicate that this authority is limited to unexpected events.[207] Additionally, DOE's implementing regulations indicate that a shortage caused by a resource's poor economics would not qualify as an emergency, unless the shortage is "imminent."[208] When promulgating these regulations, DOE noted that:

> DOE does not intend these regulations to replace prudent utility planning and system expansion. This intent has been reinforced in the final rule by expanding the "Definition of Emergency" to indicate that, while a utility may rely upon these regulations for assistance during a period of unexpected inadequate supply of electricity, it must solve long-term problems itself.[209]

(2024), https://perma.cc/G6J3-9ZL4. These capacity markets are FERC-jurisdictional, and operate according to rules contained in tariffs filed with FERC, specifying particulars like demand curve type, resource accreditation, and formulas for calculating reserve margins. *See, e.g.*, *PJM Interconnection, L.L.C.*, 191 FERC ¶ 61,066, at P 8 (2025).

203 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 1 (2011).

204 Standard BAL-502-RF-03, N. Am. Elec. Reliability Corp., https://perma.cc/9MB5-5H67.

205 *Planning Resource Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212, at P 33 (2011) ("The only obligations under BAL-502-RFC-02 are analysis and documentation requirements. This regional Reliability Standard does not specify how the results of the analysis required in this standard are to be used. For example, BAL-502-RFC-02 does not require state commissions to use the resource assessment analysis resulting from BAL-502-RFC-02 for economic decisions regarding resource adequacy requirements.").

206 16 U.S.C. § 824a(c)(1).

207 16 U.S.C. § 824a(c)(1); 10 C.F.R. § 205.371; Burçin Ünel & Avi Zevin, *supra* note 5, at 37–38.

208 10 C.F.R. § 205.371 ("Situations where a shortage of electric energy is projected due solely to the failure of parties to agree to terms, conditions or other economic factors relating to service, generally will not be considered as emergencies unless the inability to supply electric service is imminent.").

209 Emergency Interconnection of Electric Facilities and the Transfer of Electricity to Alleviate an Emergency Shortage of Electric Power, 46 Fed. Reg. 39984, 39985 (Aug. 6, 1981) (codified at 10 C.F.R. pt. 205).

In a departure from prior practice,[210] DOE has now used this authority to prevent thermal plants from retiring.[211] These orders have already drawn challenges from multiple parties, including from a politically diverse coalition of utility regulators.[212] Parties argue, among other points, that the plants' retirements were not unexpected; that the regions would be resource adequate even without the plants; and that DOE's newly asserted authority over resource adequacy triggers the major questions doctrine.[213]

Having nationally set best practices and principles for determining resource adequacy in the face of rapidly escalating demand and the clean energy transition could be useful if they are well vetted and use appropriate legal constructs. The FPA in conjunction with the DOE Reorganization Act suggest that the appropriate course of action for the federal government to support resource adequacy would be for NERC and FERC to set national resource adequacy *planning* standards (not a national resource adequacy target) to help regions guard against potential resource adequacy risks that might materialize in the future, instead of allowing DOE to stretch its 202(c) emergency authorities.

The DOE study itself cautions, "the resource adequacy analysis that was performed in support of this study could benefit greatly from the in-depth engineering assessments which occur at the regional and utility level."[214] Despite DOE's press statement asserting that the study's methodology can help guide "guide Federal reliability interventions,"[215] presumably to address the EO's mandate that DOE find a way to routinize further 202(c) emergency orders,[216] the study reports a fundamental limitation for doing so: It does not find any near-term reliability risk from current levels of resource adequacy.

The study itself states that, "one of the key takeaways from this study process is the underscored 'call to action' for strengthened regional engagement, collaboration, and robust data exchange which are critical to addressing the urgency of reliability and security concerns that underpin our

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210 Cong. Rsch. Serv., Federal Power Act: The Department of Energy's Emergency Authority 4 (updated 2025), https://perma.cc/AU8L-VR55.

211 *DOE's Use of Federal Power Act Emergency Authority*, U.S. Dep't of Energy, https://perma.cc/DPB9-6B74.

212 Ethan Howland, *Groups Appeal DOE "Emergency" Order Keeping Michigan Plan Online*, Utility Dive (updated June 20, 2025), https://perma.cc/P9YZ-FNLK; Ethan Howland, *Eight Utility Regulators Challenge DOE Order Keeping Michigan Coal Plant* Open, Utility Dive (June 26, 2025), https://perma.cc/55FE-2RYR; Motion to Intervene and Request for Rehearing of the Joint Consumer Advocates, Dep't of Energy Order No. 202-25-4 (June 27, 2025), https://perma.cc/PD74-6CNC.

213 Request for Rehearing by Michigan Attorney General Dana Nessel, Dep't of Energy Order No. 202-25-3, at 27–31, 35–36 (June 18, 2025); Motion to Intervene and Request for Rehearing and Stay of Sierra Club et al., Dep't of Energy Order No. 202-25-3, at 29–36 (June 18, 2025), https://perma.cc/4MYN-MHZC; Petition to Intervene and Request for Rehearing of the Organization of MISO States, Inc., Dep't of Energy Order No. 202-25-3, at 2–6 (June 23, 2025), https://perma.cc/D3PG-56H2. *See also* Brief of the Institute for Policy Integrity at 4–13, V.O.S. Selections, Inc. v. Trump, No. 25-00066-GSK-TMR-JAR (Ct. Int'l Trade May 8, 2025), https://perma.cc/5Z4T-8CHG (describing the major questions doctrine).

214 U.S. Dep't of Energy, Resource Adequacy Report, *supra* note 2, at i.

215 *Department of Energy Releases Report on Evaluating U.S. Grid Reliability and Security*, U.S. Dep't of Energy (July 7, 2025), https://perma.cc/942V-L7VB.

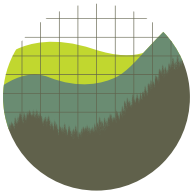
216 *See* Exec. Order No. 14,262, Strengthening the Reliability and Security of the United States Electric Grid, 90 Fed. Reg. 15521, 15521–22 (Apr. 14, 2025).

collective economic and national security." And it presents a pathway to fulfill DOE's discussion of what will happen next: "The report will inform joint planning processes and help integrate modern metrics into national reliability assessment methodology."[217] FERC directing NERC to develop national resource adequacy planning metrics, protocols, and input parameters would fit neatly within this call to action.

[217] *Reliability*, U.S. Dep't of Energy, https://perma.cc/RSW3-FNN2.

Conclusion

Given ever-increasing demand for electricity—proliferation of data centers for artificial intelligence; electrification of heating, cooling, and transportation; and pushes to onshore manufacturing—maintaining resource adequacy is essential. But there is no single answer to the question of when a system is resource adequate, or even what constitutes resource adequacy. Still, as this report explains, there are better and worse ways to pick resource adequacy targets, to evaluate whether the system has achieved and will maintain them, and to understand the resource adequacy impacts of a particular resource entering or exiting the system. The DOE Study uses some of these best practices but not other important ones, undermining the accuracy of its predictions. The DOE Study will hopefully focus additional attention on resource adequacy and speed up federal and state endeavors already underway to bolster resource adequacy. It does not, however, provide a rational basis for DOE to take action now to thwart ongoing plans for uneconomic, aging resources to retire. DOE's next best step would be to request that FERC open a proceeding eliciting proposals for nationwide, enforceable reliability standards mandating not a national resource adequacy target, but best practices for grid planners to conduct resource adequacy assessments. Additionally, states and grid operators should continue working together to expedite resource permitting, better forecast what hyperscaler demand will materialize, engage in holistic transmission planning, and speed interconnection queues—all of which will support future resource adequacy.



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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-42:
GridLab Report

1

GridLab Analysis: Department of Energy Resource Adequacy Report



Ric OConnell

Rethinking Reliability

July 11, 2025

Overview:

This memo provides a high-level overview of the recently released Department of Energy (DOE) Resource Adequacy Report, released on July 7, 2025. This report is a result of the Executive Order from the Trump Administration on Strengthening the Reliability and Security of the Grid, which directed the agency to develop and publish a methodology for "analyzing current and anticipated reserve margins for all regions of the bulk power system regulated by the Federal Energy Regulatory Commission and shall utilize this methodology to identify current and anticipated regions with reserve margins below acceptable thresholds as identified by the Secretary of Energy."

The Executive Order also directs the DOE to prevent generation sources exceeding 50 MW from retiring or converting fuel sources if it would reduce generating capacity in at-risk regions, based on the new methodology. The DOE has so far issued two emergency orders under section 202(c) of the Federal Power Act. These orders directed plant owners and grid operators to delay by 90 days the retirement of the Campbell coal plant in Michigan owned by Consumers Energy and the Eddystone gas and oil plant in Pennsylvania, owned by Constellation. The EO and its methodology report did not include a mechanism for public input.

Bottomline of the DOE report:

The report warns of a 100X increased risk of outages if the forecasted retirements by 2030 take place. The report blames the lack of "firm" generation replacement in the planned supply.

Bottomline of GridLab analysis:

The report's conclusions are problematic since the **report undercounts the resources that are likely to be added to the grid,** and **overstates** the retirements expected. Utilities and markets *already* have plans to meet increased load growth, yet the **DOE report assumes they are doing nothing after 2026**

the **DOE report assumes they are doing nothing after 2026.**

DOE Report Analysis – Key Takeaways:

- The report is based on three key assumptions: (1) the amount of load that will be added to the grid over the next five years, (2) the number of plants assumed to retire, and (3) the amount of new capacity added to the grid. The study used aggressive assumptions regarding load growth and retirements, but conservative assumptions about how much new generation capacity will be added, even assuming no new resources after 2026.
    - Load Growth: The report assumes 50 GW of data center load and allocates it regionally. It does not address flexibility of this load, however, which was recently demonstrated in a report from Duke University to allow for 100 GW of large load additions today with minimal grid impact. The DOE report then adds 51 GW of non-data center load, which means overall load growth by 2030 is 101 GW or 15%. For comparison, EIA assumed 6% growth in their Annual Energy Outlook 2025 high growth case. This is very aggressive load growth, although not necessarily unreasonable, as it is collected from each of the RTOs and utilities.
    - Retirements: The report assumed 104 GW of retirements by 2030, with 3/4 of this coal and 1/4 gas. But the most recent data from the U.S. Energy Information Administration released in June (the EIA 860) has just **half** of this capacity retiring. In the report, the DOE assumed these 50 GW of likely retirements, but included another 50 GW of *announced* retirements, inconsistent with their assumption around capacity additions. Most likely many plants will choose

not to retire due to the changing regulatory and economic landscape, driven by the administration's policies.

- Capacity Additions: The report assumes just 22 GW of new "firm" capacity (narrowly defined as gas) is added which is based on NERC LTRA "Tier 1" – projects with a very high likelihood of success. The report assumes no projects are built post 2026, which is not realistic for a report forecasting to 2030. A more reasonable assumption for capacity additions is the EIA 860 released in June, which has 35 GW of gas additions, and another 53 GW of batteries – **88 GW of firm additions by 2030.**

- The study ignores both utility plans for meeting increased load growth and how markets will respond. In fact, markets and utilities have already responded with plans to add new capacity and fast track new resources. These include PJM's Reliability Resource Initiative, which plans on adding 11 GW of new firm resources by 2030. SPP and MISO both have proposals at FERC (called ERAS) that will likely add another 30 GW of firm resources. Those three regional efforts alone would add roughly twice what the DOE assumed for the entire nation.
- This national report attempts to address what is primarily a regional issue with regional solutions. A handful of regions face pressure due to rising load growth, and those regions have already enacted plans to address this growth. For example, MISO, SPP and PJM have all instituted "fast track" processes to get firm generation online (gas and batteries), which is expected to install 43 GW of new resources by 2030. The DOE report, however, shows just 13.5 GW of new firm resources in those three regions.

DOE Report Assumptions vs. U.S. Energy Information Administration

Energy Information Administration Data:

	DOE Report	EIA 860
Load growth:	101 GW	N/A
Capacity Additions	209 GW	200 GW
Gas Capacity Additions	22 GW	35 GW
Battery Capacity Additions	31 GW	53 GW
Retirements	104 GW	52 GW

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Conclusion:

If the DOE report had used more consistent assumptions, it would have likely come to very different conclusions. Utilities and RTOs have planning processes and market mechanisms in place to build new resources in response to higher load growth and the retirement of older, uneconomic plants. The DOE's solution to keep older units online past retirement dates is a crude and expensive approach. The DOE should defer to state planning processes and regional markets to meet the challenge.

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PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-43:
Duke University Rethinking Load Growth Study

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Rethinking Load Growth

Assessing the Potential for Integration of Large Flexible Loads in US Power Systems

Tyler H. Norris, Tim Profeta, Dalia Patino-Echeverri, and Adam Cowie-Haskell

Nicholas Institute for Energy, Environment & Sustainability nicholasinstitute.duke.edu

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https://nicholasinstitute.duke.edu/publications/rethinking-load-growth

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The Nicholas Institute for Energy, Environment & Sustainability at Duke University accelerates solutions to critical energy and environmental challenges, advancing a more just, resilient, and sustainable world. The Nicholas Institute conducts and supports actionable research and undertakes sustained engagement with policymakers, businesses, and communities—in addition to delivering transformative educational experiences to empower future leaders. The Nicholas Institute's work is aligned with the Duke Climate Commitment, which unites the university's education, research, operations, and external engagement missions to address climate challenges.

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INTRODUCTION

A New Era of Electricity Demand

Rapid US load growth—driven by unprecedented electricity demand from data centers, industrial manufacturing, and electrification of transportation and heating—is colliding with barriers to timely resource expansion. Protracted interconnection queues, supply chain constraints, and extended permitting processes, among other obstacles, are limiting the development of new power generation and transmission infrastructure. Against this backdrop, there is increasing urgency to identify strategies that accommodate rising demand without compromising reliability, affordability, or progress on decarbonization.

Aggregated US winter peak load is forecasted to grow by 21.5% over the next decade, rising from approximately 694 GW in 2024 to 843 GW by 2034, according to the *2024 Long-Term Reliability Assessment* of the North American Electric Reliability Corporation. This represents a 10-year compound annual growth rate (CAGR) of 2.0%, higher than any period since the 1980s (NERC 2024). Meanwhile, the Federal Energy Regulatory Commission's (FERC) latest five-year outlook forecasts 128 GW in peak load growth as early as 2029—a CAGR of 3.0% (FERC 2024b).

The primary catalyst for these updated forecasts is the surge in electricity demand from large commercial customers. While significant uncertainty remains, particularly following the release of DeepSeek, data centers are expected to account for the single largest growth segment, adding as much as 65 GW through 2029 and up to 44% of US electricity load growth through 2028 (Wilson et al. 2024; Rouch et al. 2024). Artificial intelligence (AI) workloads are projected to represent 50% to 70% of data center demand by 2030—up from less than 3% at the start of this decade—with generative AI driving 40% to 60% of this growth (Srivathsan et al. 2024; Lee et al. 2025).

Analysts have drawn parallels to the 1950s through the 1970s, when the United States achieved comparable electric power sector growth rates (Wilson et al. 2024). Yet these comparisons arguably understate the nature of today's challenge in the face of stricter permitting obstacles, higher population density, less land availability, skilled labor shortages, persistent supply chain bottlenecks, and demand for decarbonization and greater power reliability. While historical growth rates offer a useful benchmark, the sheer volume of required new generation, transmission, and distribution capacity forecasted for the United States within a condensed timeframe appears unprecedented.

The immensity of the challenge underscores the importance of deploying every available tool, especially those that can more swiftly, affordably, and sustainably integrate large loads. The time-sensitivity for solutions is amplified by the market pressure for many of these loads to interconnect as quickly as possible. In recent months, the US Secretary of Energy Advisory Board (SEAB) and the Electrical Power Research Institute (EPRI) have highlighted a key solution: load flexibility (SEAB 2024, Walton 2024a). The promise is that the unique profile of AI data centers can facilitate more flexible operations, supported by ongoing advancements in distributed energy resources (DERs).

Flexibility, in this context, refers to the ability of end-use customers to temporarily reduce their electricity consumption from the grid during periods of system stress by using on-site generators, shifting workload to other facilities, or reducing operations.[1] When system planners can reliably anticipate the availability of this load flexibility, the immediate pressure to expand generation capacity and transmission infrastructure can potentially be alleviated, mitigating or deferring costly expenditures. By facilitating near-term load growth without prematurely committing to large-scale capacity expansion, this approach offers a hedge against mounting uncertainty in the US data center market in light of the release of DeepSeek and related developments (Kearney and Hampton 2025).

Summary of Analysis and Findings

To support evaluation of potential solutions, this study presents an analysis of the existing US electrical power system's ability to accommodate new flexible loads. The analysis, which encompasses 22 of the largest balancing authorities serving 95% of the country's peak load, provides a first-order estimate of the potential for accommodating such loads with minimal capacity expansion or impact on demand-supply balance.[2]

Specifically, we estimate the gigawatts of new load that could be added in each balancing authority (BA) before total load exceeds what system planners are prepared to serve, provided the new load can be temporarily curtailed as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.

Key results include (see Figure 1):

- 76 GW of new load—equivalent to 10% of the nation's current aggregate peak demand—could be integrated with an average annual load curtailment rate of 0.25% (i.e., if new loads can be curtailed for 0.25% of their maximum uptime)
- 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5%, and 126 GW at a rate of 1.0%
- The number of hours during which curtailment of new loads would be necessary per year, on average, is comparable to those of existing US demand response programs
- The average duration of load curtailment (i.e., the length of time the new load is curtailed during curtailment events) would be relatively short, at 1.7 hours when average annual load curtailment is limited to 0.25%, 2.1 hours at a 0.5% limit, and 2.5 hours at a 1.0% limit
- Nearly 90% of hours during which load curtailment is required retain at least half of the new load (i.e., less than 50% curtailment of the new load is required)
- The five balancing authorities with the largest potential load integration at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW[3]

1 Note that while *curtailment* and *flexibility* are used interchangeably in this paper, *flexibility* can refer to a broader range of capabilities and services, such as the provision of down-reserves and other ancillary services.

2 For further discussion on the nuances regarding generation versus transmission capacity, see the section on limitations.

3 A complete list of abbreviations and their definitions can be found at the end of the report.

Overall, these results suggest the US power system's existing headroom, resulting from intentional planning decisions to maintain sizable reserves during infrequent peak demand events, is sufficient to accommodate significant constant new loads, provided such loads can be safely scaled back during some hours of the year. In addition, they underscore the potential for leveraging flexible load as a complement to supply-side investments, enabling growth while mitigating the need for large expenditures on new capacity.

We further demonstrate that a system's potential to serve new electricity demand without capacity expansion is determined primarily by the system's load factor (i.e., a measure of the level of use of system capacity) and grows in proportion to the flexibility of such load (i.e., what percentage of its maximal potential annual consumption can be curtailed). For this reason, in this paper we assess the technical potential for a system to serve new load under different curtailment limit scenarios (i.e., varying curtailment tolerance levels for new loads).

The analysis does not consider the technical constraints of power plants that impose intertemporal constraints on their operations (e.g., minimum downtime, minimum uptime, startup time, ramping capability, etc.) and does not account for transmission constraints. However, it ensures that the estimate of load accommodation capacity is such that total demand does not exceed the peak demand already anticipated for each season by system planners, and it discounts existing installed reserve margins capable of accommodating load that exceeds historical peaks. It also assumes that new load is constant throughout all hours.

This analysis should not be interpreted to suggest the United States can fully meet its near- and medium-term electricity demands without building new peaking capacity or expanding the grid. Rather, it highlights that flexible load strategies can help tap existing headroom to more quickly integrate new loads, reduce the cost of capacity expansion, and enable greater focus on the highest-value investments in the electric power system.

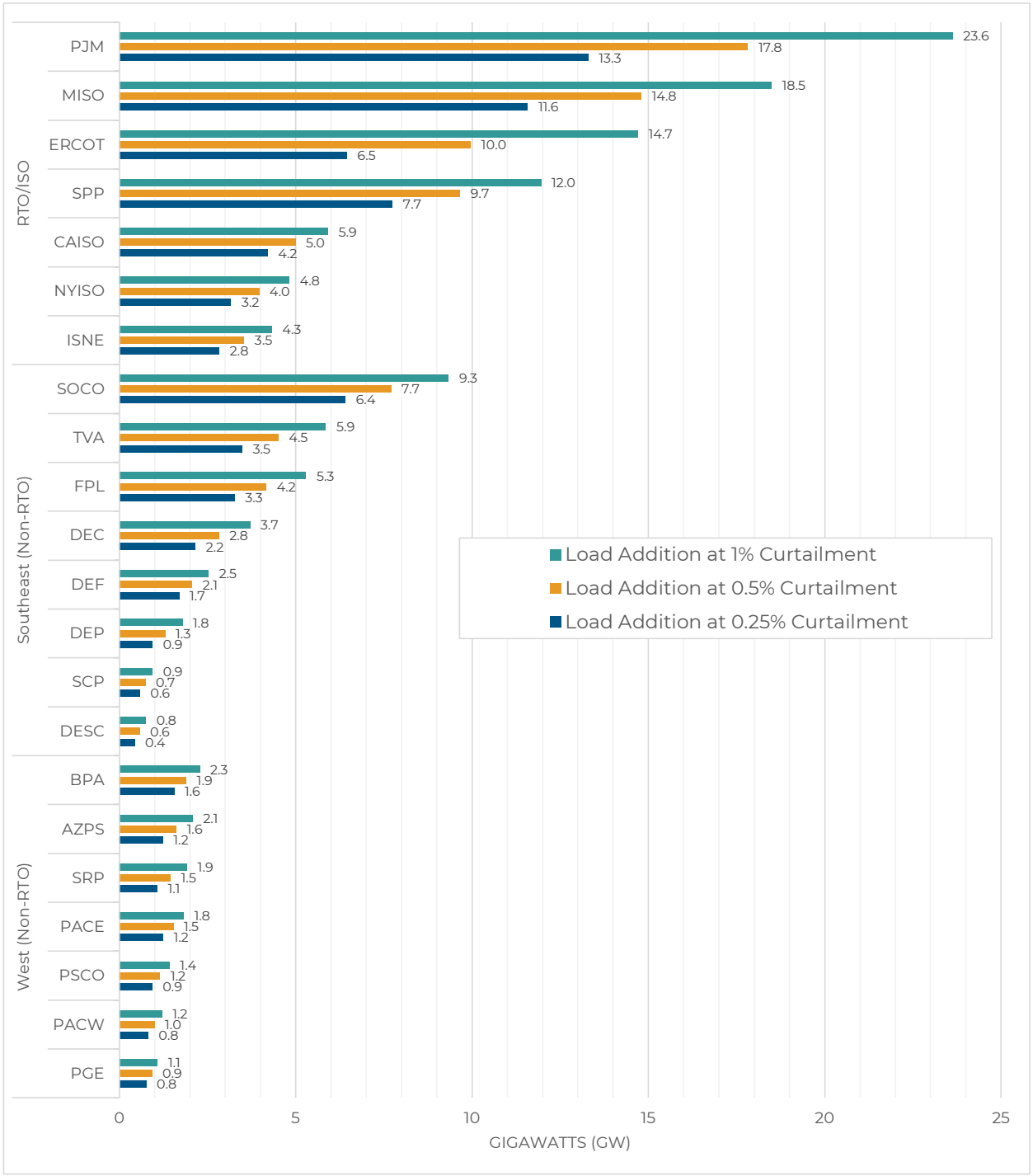
This paper proceeds as follows: the following section provides background on the opportunities and challenges to integrating large new data centers onto the grid. It explores how load flexibility can accelerate interconnection, reduce ratepayer costs through higher system utilization, and expand the role of demand response, particularly for AI-specialized data centers. We then detail the methods and results for estimating curtailment-enabled headroom, highlighting key trends and variations in system headroom and its correlation with load factors across regions. The paper concludes with a brief overview of key findings, limitations, and near-term implications.

BACKGROUND

Load Flexibility Can Accelerate Grid Interconnection

The growing demand for grid access by new large loads has significantly increased interconnection wait times, with some utilities reporting delays up to 7 to 10 years (Li et al. 2024; Saul 2024; WECC 2024). These wait times are exacerbated by increasingly severe transmission equipment supply chain constraints. In June 2024, the President's National Infrastructure Advisory Council highlighted that transformer order lead times had ballooned to two to five years—up from less than one year in 2020—while costs surged by 80% (NIAC 2024). Circuit breakers have seen similar delays: last year, the Western Area Power Administration

Figure 1. System Headroom Enabled by Load Curtailment of New Load by Balancing Authority, GW



Note: *System headroom* refers to the amount of GW by which a BA's load can be augmented every hour in the absence of capacity expansion so that, provided a certain volume of curtailment of the new load, the total demand does not exceed the supply provisioned by system planners to withstand the expected highest peak. The headroom calculation assumes the new load is constant and hence increases the total load by the same GW hour-by-hour.

reported lead times of up to four and a half years for lower voltage classes and five and a half years for higher voltage classes, alongside a 140% price hike over two years (Rohrer 2024). Wood Mackenzie reported in May 2024 that lead times for high-voltage circuit breakers reached 151 weeks in late 2023, marking a 130% year-over-year increase (Boucher 2024).

Large load interconnection delays have recently led to growing interest among data centers in colocating with existing generation facilities. At a FERC technical conference on the subject in late 2024 (FERC 2024c), several participants highlighted the potential benefits of colocation for expedited interconnection,[4] a view echoed in recent grey literature (Schatzki et al. 2024). Colocation, however, represents only a portion of load interconnections and is not viewed as a long-term, system-wide solution.

Load flexibility similarly offers a practical solution to accelerating the interconnection of large demand loads (SIP 2024, Jabeck 2023). The most time-intensive and costly infrastructure upgrades required for new interconnections are often associated with expanding the transmission system to deliver electricity during the most stressed grid conditions (Gorman et al. 2024). If a new load is assumed to require firm interconnection service and operate at 100% of its maximum electricity draw at all times, including during system-wide peaks, it is far more likely to trigger the need for significant upgrades, such as new transformers, transmission line reconductoring, circuit breakers, or other substation equipment.

To the extent a new load can temporarily reduce (i.e., curtail) its electricity consumption from the grid during these peak stress periods, however, it may be able to connect while deferring—or even avoiding—the need for certain upgrades (ERCOT 2023b). A recent study on Virginia's data center electricity load growth noted, "Flexibility in load is generally expected to offset the need for capacity additions in a system, which could help mitigate the pressure of rapid resource and transmission expansion" (K. Patel et al. 2024). The extent and frequency of required curtailment would depend on the specific nature of the upgrades; in some cases, curtailment may only be necessary if a contingency event occurs, such as an unplanned transmission line or generator outage. For loads that pay for firm interconnection service, any period requiring occasional curtailment would be temporary, ending once necessary network upgrades are completed.[5] Such "partially firm," flexible service was also highlighted by participants in FERC's 2024 technical conference on colocation.[6]

Traditionally, such arrangements have been known as *interruptible* electric service. More recently, some utilities have pursued *flexible* load interconnection options. In March 2022, for example, ERCOT implemented an interim interconnection process for large loads seeking to connect in two years or less, proposing to allow loads seeking to qualify as controllable load resources (CLRs) "to be studied as flexible and potentially interconnect more MWs" (ERCOT 2023b). More recently, ERCOT stated that "the optimal solution for grid reliability is for

4 For example, the Clean Energy Buyers Association (2024) noted, "Flexibility of co-located demand is a key asset that can enable rapid, reliable interconnection."

5 Such an arrangement is analogous to provisional interconnection service available to large generators, as defined in Section 5.9.2 of FERC's Pro Forma *Large Generator Interconnection Agreement* (LGIA).

6 MISO's market monitor representative stated, "instead of being a network firm customer, could [large flexible loads] be a non-firm, or partial non-firm [customer], and that could come with certain configuration requirements that make them truly non-firm, or partially non-firm. But, all those things are the things that could enable some loads to get on the system quicker" (FERC 2024c).

more loads to participate in economic dispatch as CLRs" (Springer 2024). Similarly, Pacific Gas and Electric (PG&E) recently introduced a Flex Connect program to allow certain loads faster access to the grid (Allsup 2024).

These options resemble interconnection services available to large generators that forgo capacity compensation, and potentially higher curtailment risk, in exchange for expedited lower-cost grid access (Norris 2023). FERC codified this approach with Energy Resource Interconnection Service (ERIS) in Order 2003 and revisited the concept during a 2024 technical workshop to explore potential improvements (Norris 2024). Some market participants have since proposed modifying ERIS to facilitate the colocation of new generators with large loads (Intersect Power 2024).

Ratepayers Benefit from Higher System Utilization

The US electric power system is characterized by a relatively low utilization rate, often referred to as the *load factor*. The load factor is the ratio of average demand to peak demand over a given period and provides a measure of the utilization of system capacity (Cerna et al. 2023). A system with a high load factor operates closer to its peak system load for more hours throughout the year, while a system with a low load factor generally experiences demand spikes that are higher than its typical demand levels (Cerna et al. 2022). This discrepancy means that, for much of the year, a significant portion of a system's available generation and transmission infrastructure is underutilized (Cochran et al. 2015).

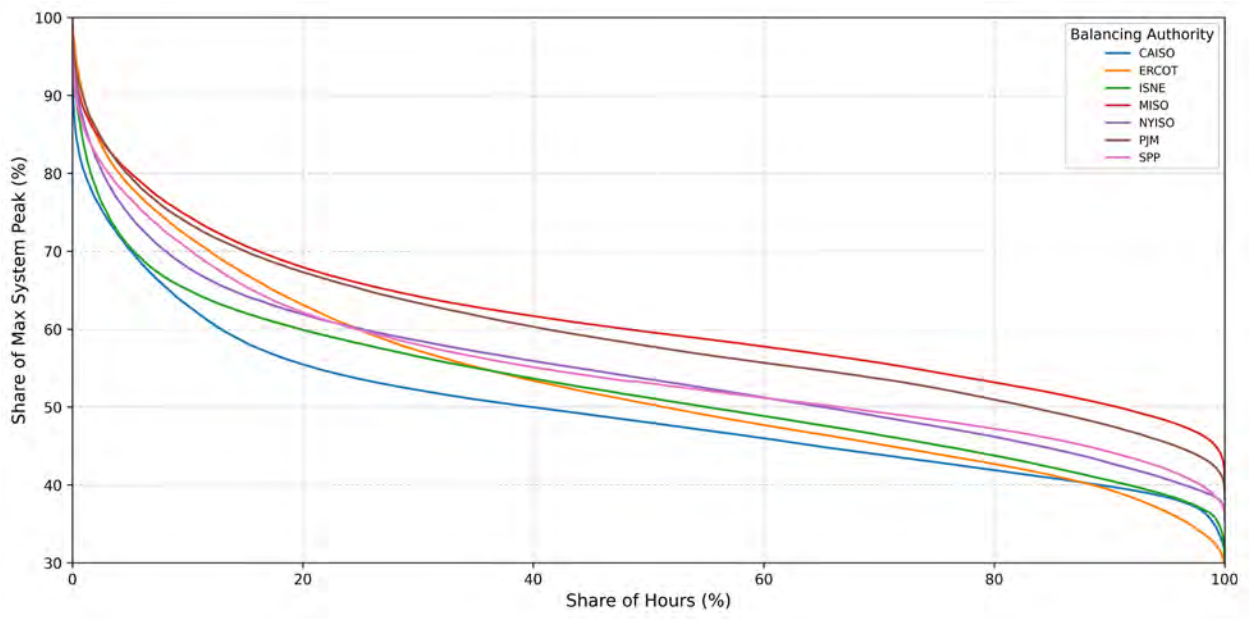
The power system is designed to handle the highest demand peaks, which in some cases may occur less than once per year, on average, due to extreme weather events. As a result, the bulk of the year sees demand levels well below that peak, leaving substantial headroom in installed capacity. Seasonal shifts add another layer of complexity: some balancing authorities may show higher load factors in summer, yet experience significantly lower utilization in winter, and vice versa.

The *load duration curve* (LDC) illustrates system utilization by ranking demand from highest to lowest over a given period. It provides a visual representation of how often certain demand levels occur, highlighting the frequency and magnitude of peak demand relative to average load. A steep LDC suggests high demand variability, with peaks significantly exceeding typical loads, while a flatter LDC indicates more consistent usage. Figure 2 presents LDCs for each US RTO/ISO based on hourly load between 2016 and 2024, standardized as a percentage of each system's maximum peak demand to allow cross-market comparisons.

A system utilization rate below 100% is expected for most large-scale infrastructure designed to withstand occasional surges in demand. Nevertheless, when the gap between average demand and peak demand is consistently large, it implies that substantial portions of the electric power system—generation assets, transmission infrastructure, and distribution networks—remain idle for much of the year (Riu et al. 2024). These assets are expensive to build and maintain, and ratepayers ultimately bear the cost.

Once the infrastructure is in place, however, there is a strong economic incentive to increase usage and spread these fixed costs over more kilowatt-hours of delivered electricity. An important consideration is therefore the potential for additional load to be added without significant new investment, provided the additional load does not raise the system's overall

Figure 2. Load Duration Curve for US RTO/ISOs, 2016–2024



This figure is adapted from the analysis section of this paper, which contains additional detail on the data and method.

peak demand and thereby trigger system expansion.[7] When new loads are flexible enough to avoid a high coincident load factor, thereby mitigating contribution to the highest-demand hours, they fit within the existing grid's headroom.[8] By strategically timing or curtailing demand, these flexible loads can minimize their impact on peak periods. In doing so, they help existing customers by improving the overall utilization rate—thereby lowering the per-unit cost of electricity—and reduce the likelihood that expensive new peaking plants or network expansions may be needed.

In contrast, inflexible new loads that increase the system's absolute peak demand can drive substantial additional needs for generation and transmission capacity. Even a modest rise in peak demand may trigger capital investments in peaking plants, fuel supply infrastructure, and reliability enhancements. These cost implications have contributed to increasingly contentious disputes in which regulators or ratepayer advocates seek to create mechanisms to pass the costs of serving large loads directly to those loads and otherwise ensure data centers do not shift costs via longer contract commitments, billing minimums, and upfront investment (Howland 2024a; Riu et al. 2024). Some examples include:

- The **Georgia Public Service Commission (GPSC)**, citing "staggering" large load growth and the need to protect ratepayers from the costs of serving those customers, recently implemented changes to customer contract provisions if peak draw exceeds 100 MW, mandating a GPSC review and allowing the utility to seek longer contracts and minimum billing for cost recovery (GPSC 2025). This follows GPSC's approval

7 See the discussion on limitations and further analysis in the following section for additional nuance.

8 Demand charges are often based on coincident consumption (e.g., ERCOT's Four Coincident Peak charge uses the load's coincident consumption at the system's expected seasonal peak to determine an averaged demand charge that may account for >30% of a user's annual bill).

of 1.4 GW of gas capacity proposed by Georgia Power in response to load growth "approximately 17 times greater than previously forecasted" through 2030/2031, a forecast it revised upward in late 2024 (GPC 2023, 2024).

- **Ohio**, where American Electric Power issued a moratorium on data center service requests, followed by a settlement agreement with the Public Service Commission staff and consumer advocates that calls for longer contract terms, load ramping schedules, a minimum demand charge, and collateral for service from data centers exceeding 25 MW (Ohio Power Company 2024).
- **Indiana**, where 4.4 GW of interconnection requests from a "handful" of data centers represents a 157% increase in peak load for Indiana Michigan Power over the next six years. Stakeholders there have proposed "firewalling" the associated cost of service from the rest of the rate base, wherein the utility would procure a separate energy, capacity, and ancillary resource portfolio for large loads and recover that portfolio's costs from only the qualifying large loads (Inskeep 2024).
- **Illinois**, where Commonwealth Edison reported that large loads have paid 8.2% of their interconnection costs while the remaining 91.8% is socialized across general customers (ComEd 2024).

These examples underscore the significance of exploring how flexible loads can mitigate peak increases, optimize the utilization of existing infrastructure, and reduce the urgency for costly and time-consuming capacity expansions.

Demand Response and Data Centers

Demand response refers to changes in electricity usage by end-use customers to provide grid services in response to economic signals, reliability events, or other conditions. Originally developed to reduce peak loads (also called *peak shaving*), demand response programs have evolved to encompass a variety of grid services, including balancing services, ancillary services, targeted deferral of grid upgrades, and even variable renewable integration (Hurley et al. 2013; Ruggles et al. 2021). Demand response is often referred to as a form of *demand-side management* or *demand flexibility* (Nethercutt 2023).

Demand response is the largest and most established form of virtual power plant (Downing et al. 2023), with 33 GW of registered capacity in wholesale RTO/ISO programs and 31 GW in retail programs as of 2023 (FERC 2024a).[9] As a share of peak demand, participation in RTO/ISO programs ranges from a high of 10.1% in MISO to a low of 1.4% in SPP. A majority of enrolled capacity in demand response programs are industrial or commercial customers, representing nearly 70% of registered capacity in retail (EIA 2024).

Following a decade of expansion, growth in demand response program participation stalled in the mid-2010s partially because of depressed capacity prices, forecasted over-capacity, and increasingly restrictive wholesale market participation rules (Hledik et al. 2019). However, the resurgence of load growth and increasing capacity prices, coupled with ongoing advancements in DERs and grid information and communication technologies (ICT) appears likely to reverse this trend.

9 RTO/ISO and retail data may overlap.

Studies of national demand response potential have identified a range of potential scenarios (Becker et al. 2024), ranging as high as 200 GW by 2030 in a 2019 study, comprising 20% of the then-forecasted system peak and yielding $15 billion in annual benefits primarily via avoided generation and transmission and distribution (T&D) capacity (Hledik et al. 2019). Notably, this research was conducted before recent load growth forecasts.

The Participation Gap: Data Centers and Demand Response

For nearly two decades, computational loads—and data centers in particular—have been identified as a promising area for demand response. Early studies explored these capabilities, such as a two-phase Lawrence Berkeley National Laboratory study drawing on six years of research, which concluded in 2010 that "data centers, on the basis of their operational characteristics and energy use, have significant potential for demand response" (Ghatikar et al. 2010) and in 2012 that "[certain] data centers can participate in demand response programs with no impact to operations or service-level agreements" (Ghatikar et al. 2012). The 2012 study provided one of the earliest demonstrations of computational load responsiveness, finding that 10% load shed can typically occur within 6 to 15 minutes.

Despite this promise, data centers have historically exhibited low participation rates in demand response programs as a result of operational priorities and economic incentives (Basmadjian 2019; Clausen et al. 2019; Wierman et al. 2014). Data centers are designed to provide reliable, uninterrupted service and generally operate under service-level agreements (SLAs) that mandate specific performance benchmarks, including uptime, latency, and overall quality of service. Deviation from these standards can result in financial penalties and reputational harm, creating a high-stakes environment where operators are averse to operational changes that introduce uncertainty or risk (Basmadjian et al. 2018).

Compounding this challenge is the increasing prevalence of large-scale colocated data centers, which represent a significant share of the data center market (Shehabi et al. 2024). These facilities house multiple tenants, each with varying operational requirements. Coordinating demand response participation in such environments introduces layers of administrative and logistical complexity, as operators must mediate cost- and reward-sharing agreements among tenants. Further, while data centers possess significant technical capabilities, tapping these capabilities for demand response requires sophisticated planning and expertise, which some operators may not have needed to date (Silva et al. 2024).

Economic considerations have further compounded this reluctance. Implementing a demand response program requires investments in advanced energy management systems, staff training, and integration with utility platforms for which costs can be material, particularly for smaller or midsized facilities. At the same time, financial incentives provided by most demand response programs have historically been modest and insufficient to offset the expenses and opportunity costs associated with curtailed operations. For operators focused on maintaining high utilization rates and controlling costs, the economic proposition of demand response participation may be unattractive.

Existing demand response program designs may inadvertently discourage participation. Many programs were originally created with traditional industrial consumers in mind, with different incentives and operational specifications. Price-based programs may require high price variability to elicit meaningful responses, while direct control programs without sufficient guardrails may introduce unacceptable risks related to uptime and performance. The

complexity of active participation in demand response markets, including bidding processes and navigating market mechanisms, adds another layer of difficulty. Without streamlined participation structures, tailored incentives, and metrics that reflect the scale and responsiveness of data centers, many existing demand response programs may be ill-suited to the operational realities of modern data centers.

Table 1. Key Data Center Terms

Term	Definition
AI workload	A broad category encompassing computational tasks related to machine learning, natural language processing, generative AI, deep learning, and other AI-driven applications.
AI-specialized data center	Typically developed by hyperscalers, this type of facility is optimized for AI workloads and relies heavily on high-performance graphics processing units (GPUs) and advanced central processing units (CPUs) to handle intensive computing demands.
Computational load	A category of electrical demand primarily driven by computing and data processing activities, ranging from general-purpose computing to specialized AI model training, cryptographic processing, and high-performance computing (HPC).
Conventional data center	A facility that could range from a small enterprise-run server room to a large-scale cloud data center that handles diverse non-AI workloads, including file sharing, transaction processing, and application hosting. These facilities are predominantly powered by CPUs.
Conventional workload	A diverse array of computing tasks typically handled by CPUs, including file sharing, transaction processing, application hosting, and similar operations.
Cryptomine	A dedicated server farm optimized for high-throughput operations on blockchain networks, typically focused on validating and generating cryptocurrency.
Hyperscalers/hyperscale data centers	Large, well-capitalized cloud service providers that build hyperscale data centers to achieve scalability and high performance at multihundred megawatt scale or larger (Howland 2024b, Miller 2024).
Inferencing	The ongoing application of an AI model, where users prompt the model to provide responses or outputs. According to EPRI, inferencing represents 60% of an AI model's annual energy consumption (Aljbour and Wilson 2024).
Model training	The process of developing and training AI models by processing vast amounts of data. Model training accounts for 30–40% of annual AI power consumption and can take weeks or months to complete (Aljbour and Wilson 2024).

Rethinking Data Centers with AI-Driven Flexibility

Limited documentation of commercial data center participation in demand response has reinforced a perception that these facilities' demands are inherently inflexible loads. A variety of recent developments in computational load profiles, operational capabilities, and broader market conditions, however, suggest that a new phase of opportunity and necessity is emerging.

In a July 2024 memo on data center electricity demand, the SEAB recommended the Department of Energy prioritize initiatives to characterize and advance data center load flexibility, including the development of a "flexibility taxonomy and framework that explores the financial incentives and policy changes needed to drive flexible operation" (SEAB 2024). Building on these recommendations, EPRI announced a multi-year Data Center Flexible Load Initiative (DCFlex) in October 2024 with an objective "to spark change through hands-on and experiential demonstrations that showcase the full potential of data center operational flexibility and facility asset utilization," in partnership with multiple tech companies, electric utilities, and independent system operators (Walton 2024a).[10]

The central hypothesis is that the evolving computational load profiles of AI-specialized data centers facilitate operational capabilities that are more amendable to load flexibility. Unlike the many real-time processing demands typical of conventional data center workloads, such as cloud services and enterprise applications, the training of neural networks that power large language models and other machine learning algorithms is deferrable. This flexibility in timing, often referred to as *temporal flexibility*, allows for the strategic scheduling of training as well as other delay-tolerant tasks, both AI and non-AI alike. These delay-tolerant tasks are also referred to as *batch processing* and are typically not user-prompted (AWS 2025).

This temporal flexibility complements the developing interest in *spatial flexibility*, the ability to dynamically distribute workloads across one or multiple data centers in different geographic locations, optimizing resource utilization and operational efficiency. As stated by EPRI in a May 2024 report, "optimizing data center computation and geographic location to respond to electricity supply conditions, electricity carbon intensity, and other factors in addition to minimizing latency enables data centers to actively adjust their electricity consumption … some could achieve significant cost savings—as much as 15%—by optimizing computation to capitalize on lower electric rates during off-peak hours, reducing strain on the grid during high-demand periods" (EPRI 2024). For instance, having already developed a temporal workload shifting system, Google is seeking to implement spatial flexibility as well (Radovanović 2020).

In addition to temporal and spatial flexibility, other temporary load reduction methods may also enable data center flexibility. One approach is dynamic voltage and frequency scaling, which reduces server power consumption by lowering voltage or frequency at the expense of processing speed (Moons et al. 2017; Basmadjian 2019; Basmadjian and de Meer 2018). Another is server optimization, which consolidates workloads onto fewer servers while idling or shutting down underutilized ones, thereby reducing energy waste (Basmajian 2019; Chaurasia et al. 2021). These load reduction methods are driven by advances in virtual workload management, made possible by the "virtualization" of hardware (Pantazoglou et al. 2016).

10 Pointing to EPRI's new DCFlex Initiative, Michael Liebreich noted in a recent essay, "For instance, when they see how much it costs to work 24/7 at full power, perhaps data-center owners will see a benefit to providing some demand response capacity… " (Liebreich 2024).

Finally, temperature flexibility leverages the fact that cooling systems account for 30% to 40% of data center energy consumption (EPRI 2024). For instance, operators can increase cooling during midday when solar energy is abundant and reduce cooling during peak evening demand.[11] While these methods may be perceived as uneconomic due to potential impacts on performance, hardware lifespan, or SLAs, they are not intended for continuous use. Instead, they are best suited for deployment during critical hours when grid demand reduction is most valuable.

Beyond peak shaving, data centers also hold potential to participate in ancillary services, particularly those requiring rapid response, such as frequency regulation. Studies have described how data centers can dynamically adjust workloads to provide real-time support to the grid, effectively acting as "virtual spinning reserves" that help stabilize grid frequency and integrate intermittent renewable resources (McClurg et al. 2016; Al Kez et al. 2021; Wang et al. 2019). This capability extends beyond traditional demand response by providing near-instantaneous balancing resources (Zhang et al. 2022).

Three overarching market trends create further opportunities for load flexibility now than in the past. The first is constrained supply-side market conditions that raise costs and lead times for the interconnecting large inflexible loads, when speed to market is paramount for AI developers. The second is advancements in on-site generation and storage technologies that have lowered costs and expanded the availability of cleaner and more commercially viable behind-the-meter solutions, increasing their appeal to data center operators (Baumann et al. 2020). The third is the growing concentration of computational load in colocated or hyper-scale data centers—accounting for roughly 80% of the market in 2023—which is lending scale and specialization to more sophisticated data center operators. These operators, seek-ing speed to market, may be more likely to adopt flexibility in return for faster interconnec-tion (Shehabi et al. 2024; Basmadjian et al. 2018). The overarching trends underpinning this thesis are summarized in Table 2.

An important consideration for future data center load profiles is the balance between AI-specialized data centers focused on model development and those oriented toward inferencing. If fewer AI models are developed, a larger proportion of computing resources will shift toward inferencing tasks, which is delay-intolerant and variable (Riu et al. 2024). According to EPRI, training an AI model accounts for 30% of its annual footprint, compared to 60% for inferencing the same model (EPRI 2024).

In the absence of regulatory guidance, most advancements in data center flexibility to date are being driven by voluntary private-sector initiatives. Some hyperscalers and data center developers are taking steps to mitigate grid constraints by prioritizing near-term solutions for load flexibility. For example, one such company, Verrus, has established its business model around the premise that flexible data center operations offer an effective solution for growth needs (SIP 2024). Table 3 highlights additional initiatives related to facilitating or demonstrating data center flexibility.

11 Cooling demand for servers is inherently dependent on server workloads. Therefore, reducing workloads saves on cooling needs as well.

Table 2. Trends Enabling Data Center Load Flexibility

Category	Legacy	Future
Computational load profile	• Conventional servers with CPU-dominated workloads (Shehabi et al. 2024) • Real-time, delay-intolerant, and unscheduled processing (e.g., cloud services, enterprise apps) • Low latency critical	• AI-specialized servers with GPU or tensor processing unit (TPU)-favored workloads (Shehabi et al. 2024) • Greater portion of delay-tolerant and scheduled machine learning workloads (model training, non-interactive services) • Higher share of model training affords greater demand predictability • Highly parallelized workloads (Shehabi et al. 2024)
Operational capabilities	• Minimal temporal load shifting • Minimal spatial load migration • High proximity to end users for latency-sensitive tasks • Reliance on Tier 2 diesel generators for backup • Limited utilization of on-site power resulting from pollution concerns and regulatory restrictions (Cary 2023)	• More robust and intelligent temporal workload shifting (Radovanović et al. 2022) • Advanced spatial load migration and multi–data center training (D. Patel et al. 2024) • Flexibility in location for model training • Backup power diversified (storage, renewables, natural gas, cleaner diesel) • Cleaner on-site power enables greater utilization
Market conditions	• Minimal electric load growth • High availability of T&D network headroom • Standard interconnection timelines and queue volumes • Low supply chain bottlenecks for T&D equipment • Low capacity prices and forecasted overcapacity • High cost of clean on-site power options • Small-scale “server room” model	• High electric load growth • Low availability of T&D network headroom • Long interconnection timelines and overloaded queues • High supply chain bottlenecks for T&D equipment • High capacity prices and forecasted undercapacity (Walton 2024b) • Lower cost of clean on-site power options (Baranko et al. 2024) • Data center operations concentrating in large-scale facilities and operators

Table 3. Implementations of Computational Load Flexibility

Category	Examples
Operational flexibility	• Google deployed a "carbon-aware" temporal workload–shifting algorithm and is now seeking to develop geographic distribution capabilities (Radovanović 2020). • Google data centers have participated in demand response by reducing non-urgent compute tasks during grid stress events in Oregon, Nebraska, the US Southeast, Europe, and Taiwan (Mehra and Hasegawa 2023). • Enel X has supported demand response participation by data centers in North America, Ireland, Australia, South Korea, and Japan, including use of on-site batteries and generators to enable islanding within minutes (Enel X 2024). • Startup companies like Emerald AI are developing software to enable large-scale demand response from data centers through recent advances in computational resource management to precisely deliver grid services while preserving acceptable quality of service for compute users
On-site power	• Enchanted Rock, an energy solutions provider that supported Microsoft in building a renewable natural gas plant for a data center in San Jose, CA, created a behind-the-meter solution called Bridge-to-Grid, which seeks to provide intermediate power until primary service can be switched to the utility. At that point, the on-site power transitions to flexible backup power (Enchanted Rock 2024, 2025).
Market design and utility programs	• ERCOT established the Large Flexible Load Task Force and began to require the registration of large, interruptible loads seeking to interconnect with ERCOT for better visibility into their energy demand over the next five years (Hodge 2024). • ERCOT's demand response program shows promise for data center flexibility, with 750+ MW of data mining load registered as CLRs, which are dispatched by ERCOT within preset conditions (ERCOT 2023a). • PG&E debuted Flex Connect, a pilot that provides quicker interconnection service to large loads in return for flexibility at the margin when the system is constrained (Allsup 2024, St. John 2024).
Cryptomining	• A company generated more revenue from its demand response participation in ERCOT than from Bitcoin mining in one month, at times accommodating a 95% load reduction during peak demands (Riot Platforms 2023).

ANALYSIS OF CURTAILMENT-ENABLED HEADROOM

In this section we describe the method for estimating the gigawatts of new load that could be added to existing US power system load before the total exceeds what system planers are prepared to serve, provided that load curtailment is applied as needed. This serves as a proxy for the system's ability to integrate new load, which we term *curtailment-enabled headroom*.[12] We first investigated the aggregate and seasonal load factor for each of the 22 investigated balancing authorities, which measures a system's average utilization rate. Second, we computed the curtailment-enabled headroom for different assumptions of ac-

12 SEAB proposed a similar term, *available flex capacity*, in its July 2024 report *Recommendations on Powering Artificial Intelligence and Data Center Infrastructure*.

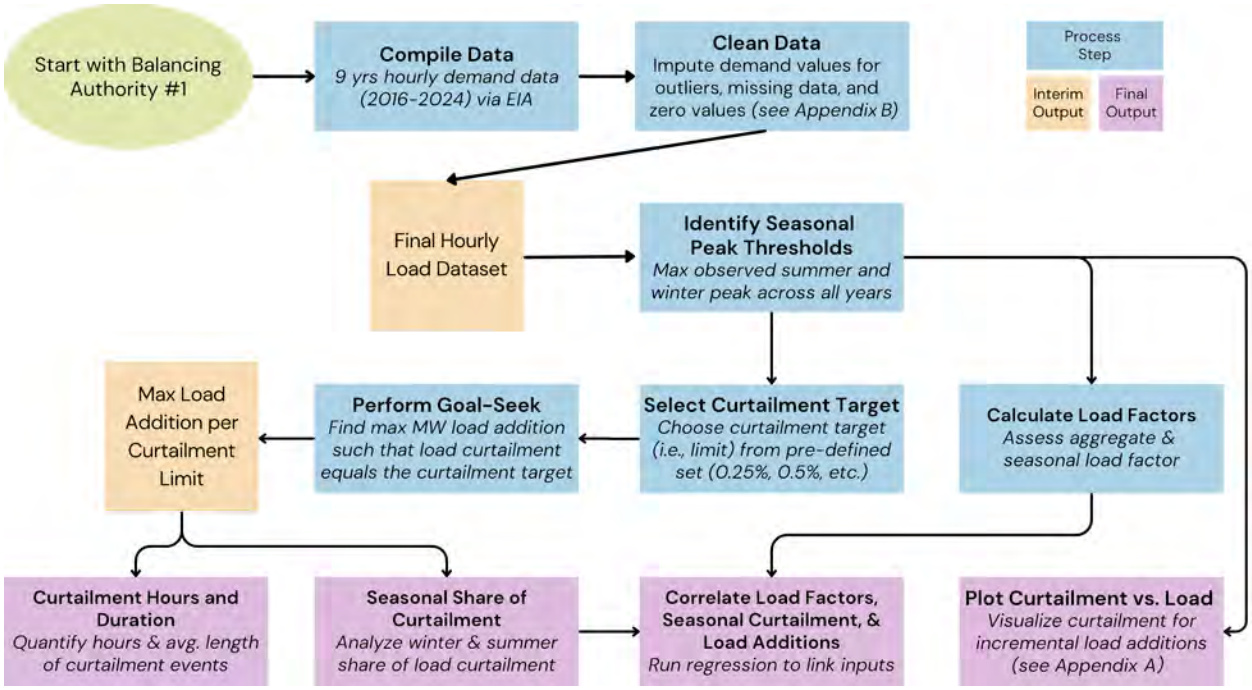
ceptable new load curtailment rates. In this context, *curtailment* refers to instances where the new load temporarily reduces its electricity draw—such as by using on-site generation resources, shifting load temporally or spatially, or otherwise reducing operations—to ensure system demand does not exceed historical peak thresholds. Third, we quantified the magnitude, duration, and seasonal concentration of the load curtailment for each balancing authority. Finally, we examined the correlation between load factor, seasonal curtailment, and max potential load additions. This process is summarized in Figure 3.

Data and Method

Data

We considered nine years of hourly load data aggregated for each of the 22 balancing authorities, encompassing seven RTO/ISOs,[13] eight non-RTO Southeastern BAs,[14] and seven non-RTO Western BAs.[15] Together, these balancing authorities represent 744 of the approximate 777 GW of summer peak load (95%) across the continental United States. The dataset, sourced from the EIA Hourly Load Monitor (EIA-930), contains one demand value per hour

Figure 3. Steps for Calculating Headroom and Related Metrics



13 CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM, and SPP.

14 DEC; DEP; DEF; DESC; FPL; Santee Cooper, SCP; Southern Company (SOCO); and TVA. Note the different BA codes used by EIA: DUK for DEC, CPLE for DEP, SCEG for DESC, FPC for DEF, and SC for SCP. Also note that Southern Company includes Georgia Power, Alabama Power, and Mississippi Power. A complete list of abbreviations and their definitions can be found at the end of the paper.

15 AZPS, BPA, PACE, PACW, PGE, PSCO, and SRP. Note that EIA uses the code BPAT for BPA. A complete list of abbreviations and their definitions can be found at the end of the paper.

and spans January 1, 2016, through December 31, 2024.[16] Data from 2015 were excluded because of incomplete reporting.[17] The dataset was cleaned to identify and impute values for samples with missing or outlier demand values (see details in Appendix B).

Determining Load Additions for Curtailment Limits

An analysis was conducted to determine the maximum load addition for each balancing authority that can be integrated while staying within predefined curtailment limits applied to the new load. The load curtailment limits (0.25%, 0.5%, 1.0%, and 5.0%) were selected within the range of maximum curtailment caps for existing interruptible demand response programs.[18] The analysis focused on finding the load addition volume in megawatts that results in an average annual load curtailment rate per balancing authority that matches the specified limit. To achieve this, a goal-seek technique was used to solve for the load addition that satisfies this condition,[19] for which the mathematical expression is presented in Appendix C. The calculation assumed the new load is constant and hence increases the total system load by the same gigawatt volume hour-by-hour. To complement this analysis and visualize the relationship between load addition volume and curtailment, curtailment rates were also calculated across small incremental load additions (i.e., 0.25% of the BA's peak load).

Load Curtailment Definition and Calculation

Load curtailment is defined as the megawatt-hour reduction of load required to prevent the augmented system demand (existing load + new load) from exceeding the maximum seasonal system peak threshold (e.g., see Figure 4). Curtailment was calculated hourly as the difference between the augmented demand and the seasonal peak threshold. These hourly curtailments in megawatt-hours were aggregated for all hours in a year to determine the total annual curtailment. The curtailment rate for each load increment was defined as the total annual curtailed megawatt-hours divided by the new load's maximum potential annual consumption, assuming continuous operation at full capacity.

Peak Thresholds and Seasonal Differentiation

Balancing authorities develop resource expansion plans to support different peak loads in winter and summer. To account for variation, we defined seasonal peak thresholds for each balancing authority. Specifically, we identified the maximum summer peak and the maximum winter peak observed from 2016 to 2024 for each balancing authority.[20] These thresholds serve as the upper limits for system demand during their respective seasons, and all

16 Additional detail on EIA's hourly load data collection is available at https://www.eia.gov/electricity/gridmonitor/about.

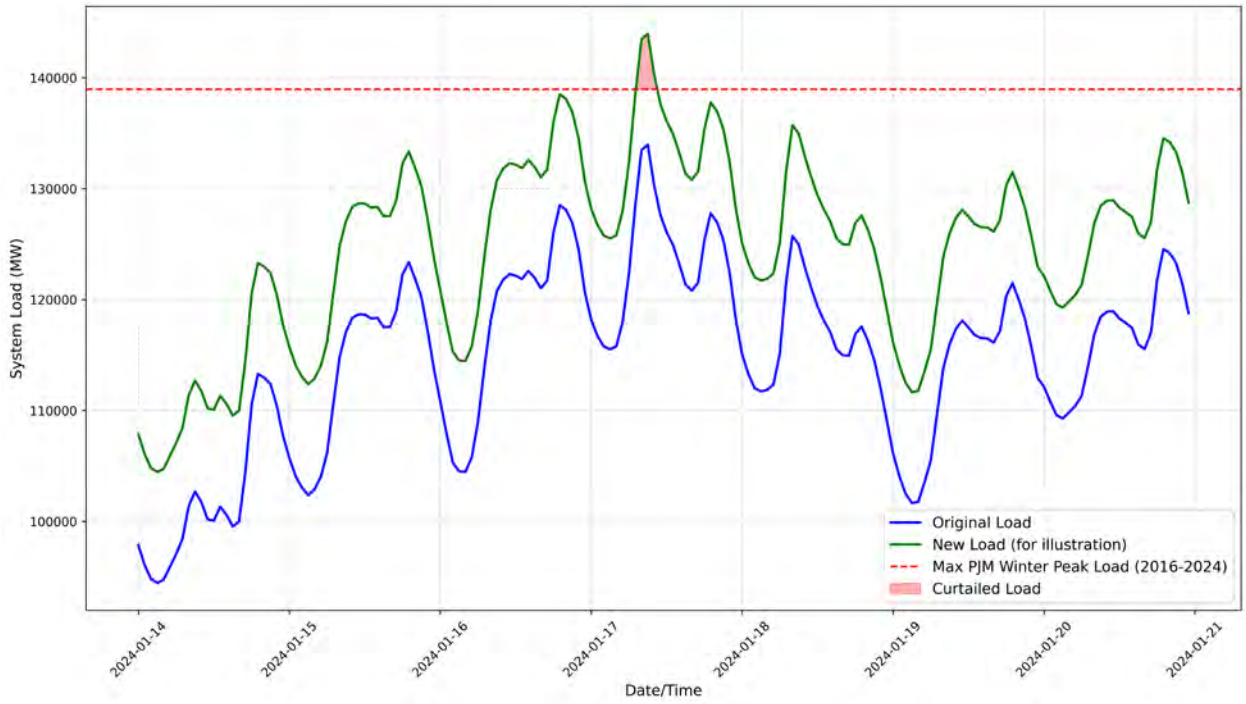
17 Fewer than half of the year's load hours were available, making the data unsuitable for inclusion.

18 For example, PG&E's and Southern California Edison's Base Interruptible Programs limit annual interruption for registered customers to a maximum of 180 hours (2.0% of all annual hours) or 10 events per month.

19 The goal-seek approach was implemented using Python's scipy.optimize.root_scalar function from the SciPy library. This tool is designed for solving one-dimensional root-finding problems, where the goal is to determine the input value that satisfies a specified equation within a defined range.

20 To identify the max seasonal peak load, summer was defined as June–August, while winter encompassed December–February. In a few cases, the BA's seasonal peak occurred within one month of these periods (AZPS winter, FPL winter, CAISO summer, CAISO winter), which were used as their max seasonal peak. To account for potential (albeit less likely) curtailment in shoulder months, the applicable summer peak was applied to April–May and September–October and the winter peak to November and March.

Figure 4. Illustrative Load Flexibility in PJM



megawatt-hours that exceeded these thresholds was counted as curtailed energy. This seasonal differentiation captures the distinct demand characteristics of regions dominated by cooling loads (summer peaks) versus heating loads (winter peaks).

Year-by-Year Curtailment Analysis

Curtailment was analyzed independently for each year from 2016 to 2024. This year-by-year approach captures temporal variability in demand patterns, including the effects of extreme weather events and economic conditions. For each year, curtailment volumes were calculated across all load addition increments, resulting in a list of annual curtailment rates corresponding to each load increment. To synthesize results across years, we calculated the average curtailment rate for each load addition increment by averaging annual curtailment rates over the nine years. This averaging process smooths out year-specific anomalies and provides an estimate of the typical system response to additional load. This analysis was also used to calculate the average number of hours of curtailment for each curtailment limit and the seasonal allocation of curtailed generation.[21] We also assessed the magnitude of load curtailment required during these hours as a share of the new load's maximum potential draw to calculate the number of hours when 90%, 75%, and 50% or more of the load would still be available.

21 Consistent with the curtailment analysis, summer was defined as June–August and winter as December–February. For BAs located on the Pacific coast (BPA, CAISO, PGE, PACE, PACW), November was counted as winter given the region's unique seasonal load profile.

Figure 5. Load Factor by Balancing Authority and Season, 2016–2024

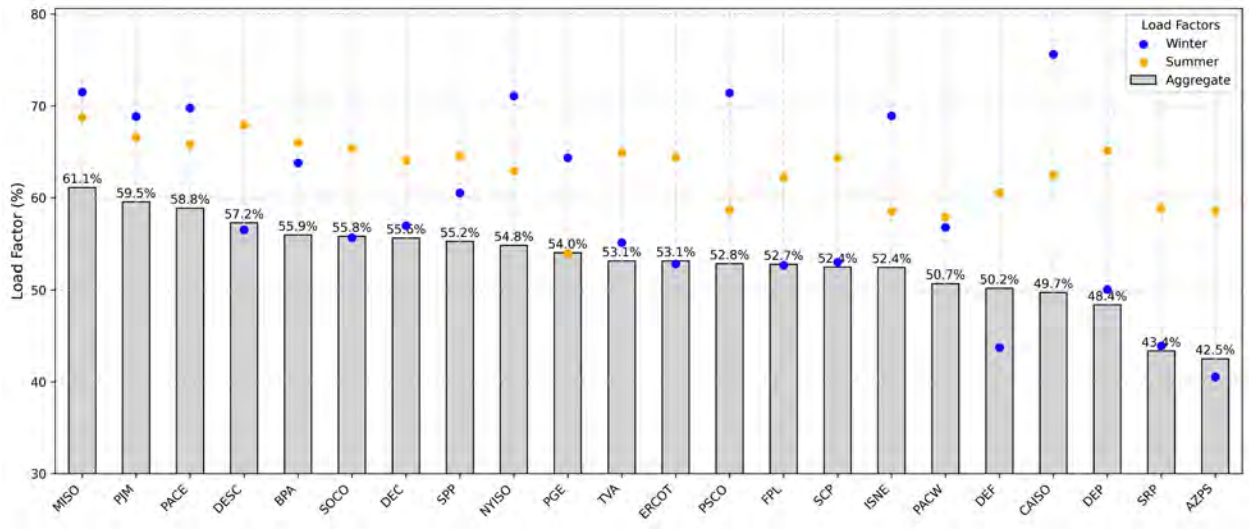
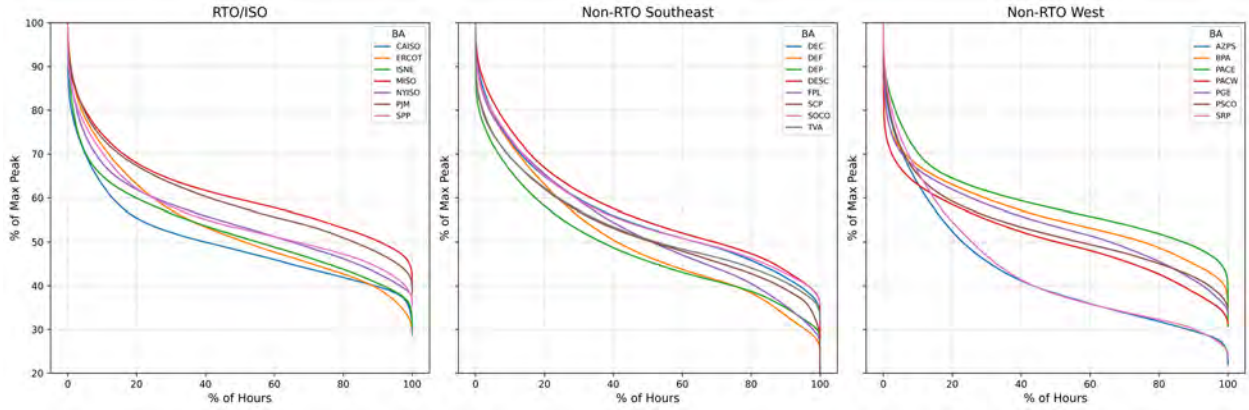


Figure 6. Load Duration Curves by Balancing Authority, 2016–2024



Results

Load Factor

In examining data for 22 balancing authorities, we found that aggregate load factors ranged between 43% to 61% (Figures 5 and 6), with an average and median value of 53%. The BAs with the lowest aggregate load factors were those in the desert southwest, Arizona Public Service Company (AZPS) and Salt River Project Agricultural Improvement and Power District (SRP). In terms of seasonal load factor, defined here as the average seasonal load as a share of seasonal maximum load (i.e., not as a share of the maximum all-time system load), winter load factors were notably lower than summer. The average and median winter load factor was 59% and 57% respectively, compared to 63% and 64% for summer. A majority of the balancing authorities had higher summer load factors (14) than winter (8).

Headroom Volume

Results show that the headroom across the 22 analyzed balancing authorities is between 76 to 215 GW, depending on the applicable load curtailment limit. This means that 76 to 215 GW of load could be added to the US power system and yet the total cumulative load would remain below the historical peak load, except for a limited number of hours per year

Figure 7. Headroom Enabled by Load Curtailment Thresholds, GW

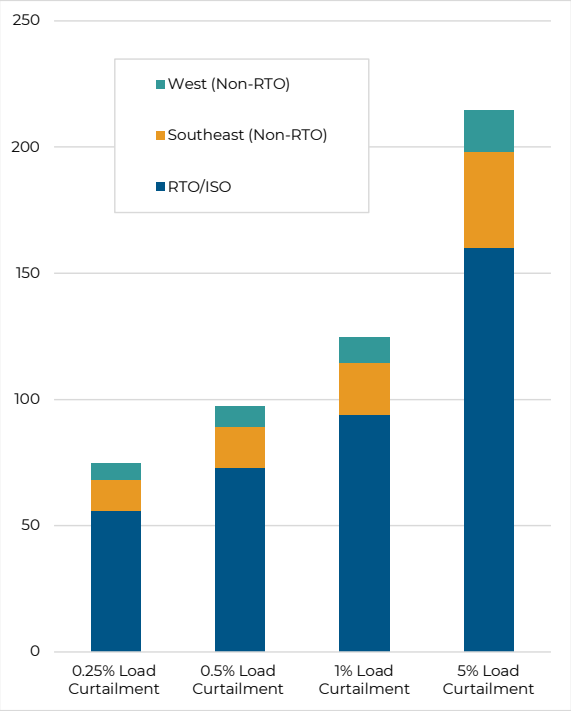


Figure 8. Headroom Enabled by 0.5% Load Curtailment by Balancing Authority, GW

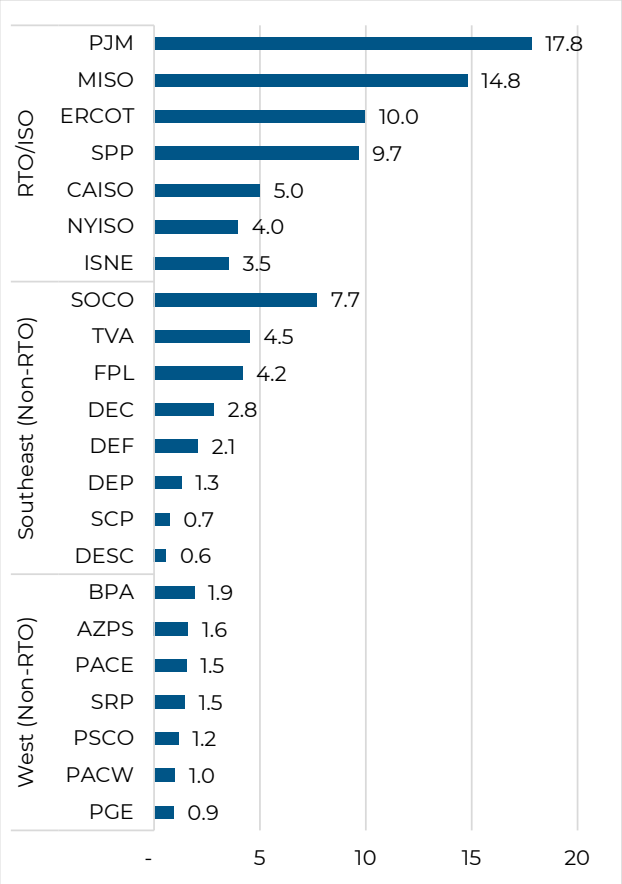
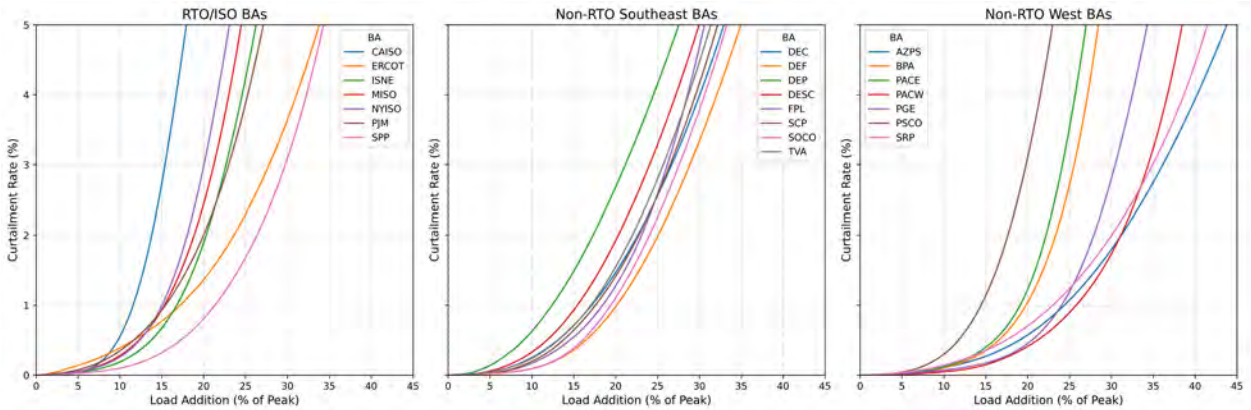


Figure 9. Load Curtailment Rate Due to Load Addition, % of System Peak



when the new load would be unserved. Specifically, 76 GW of headroom is available at an expected load curtailment rate of 0.25% (i.e., if 0.25% of the maximum potential annual energy consumption of the new load is curtailed during the highest load hours, or 1,643 out of 657,000 GWh). This headroom increases to 98 GW at 0.5% curtailment, 126 GW at 1.0% curtailment, and 215 GW at 5.0% curtailment (Figure 7). Headroom varies by balancing authority (Figure 8), including as a share of system peak (Figure 9). The five balancing authorities with the highest potential volume at 0.5% annual curtailment are PJM at 18 GW, MISO at 15 GW, ERCOT at 10 GW, SPP at 10 GW, and Southern Company at 8 GW. Detailed plots for each balancing authority, including results for each year, can be found in Appendix A.

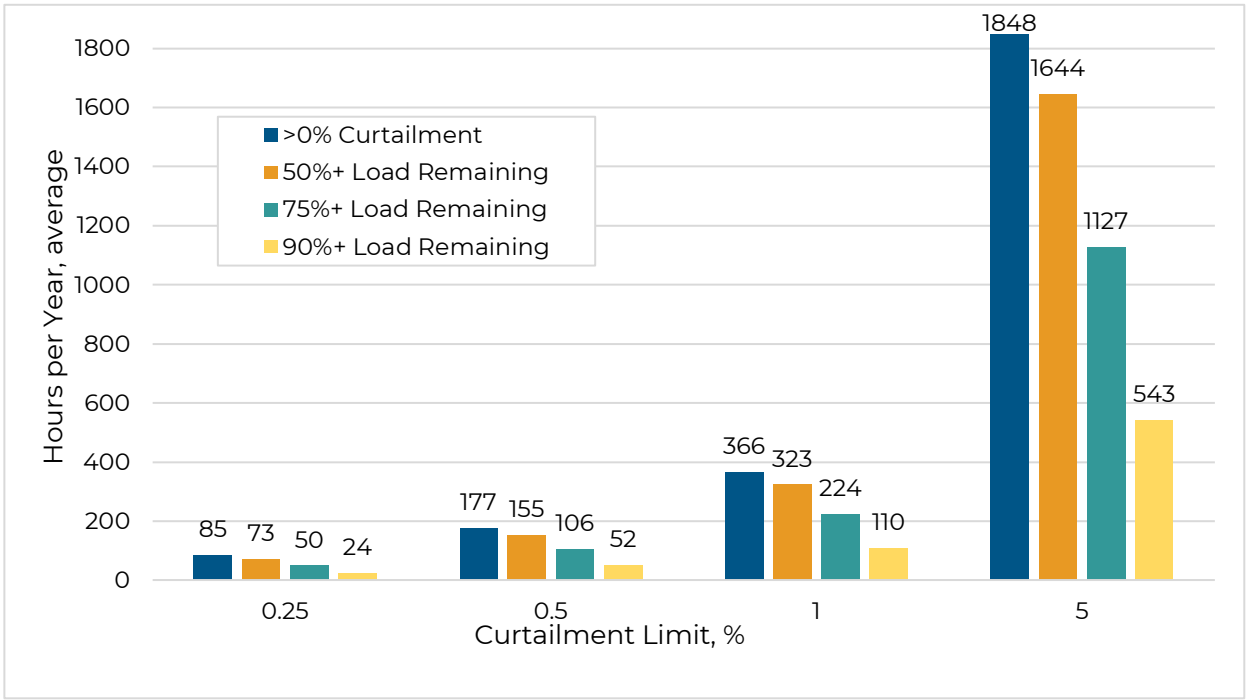
Curtailment Hours

A large majority of curtailment hours retain most of the new load. Most hours during which load reduction is required entail a curtailment rate below 50% of the new load. Across all 22 BAs, the average required load curtailment times are 85 hours under the 0.25% curtailment rate (~1% of the hours in a year), 177 hours under the 0.5% curtailment rate, 366 hours under the 1.0% curtailment rate, and 1,848 hours under the 5.0% curtailment rate (i.e., ~21% of the hours). On average, 88% of these hours retain at least 50% of the new load (i.e., less than 50% curtailment of the load is required), 60% of the hours retain at least 75% of the load, and 29% retain at least 90% of the load (see Figure 10).

Curtailment Duration

The analysis calculated the average hourly duration of curtailment events (i.e., the length of time the new load is curtailed during curtailment events). All hours in which any curtailment occurred were included, regardless of magnitude. The results for each balancing authority and curtailment limit are presented in Figure 11. The average duration across BAs was 1.7 hours for the 0.25% limit, 2.1 hours for the 0.5% limit, 2.5 hours for the 1.0% limit, and 4.5 hours for the 5.0% limit.

Figure 10. Hours of Curtailment by Load Curtailment Limit



Seasonal Concentration of Curtailment

The analysis reveals significant variation in the seasonal concentration of curtailment hours across balancing authorities. The winter-summer split ranged from 92% to 1% for CAISO (California Independent System Operator), where curtailment is heavily winter-concentrated, to 0.2% to 92% for AZPS,[22] which exhibited a heavily summer-concentrated curtailment profile (Figure 12a).[23]

Figure 11. Average Curtailment Duration by Balancing Authority and Curtailment Limit, Hours

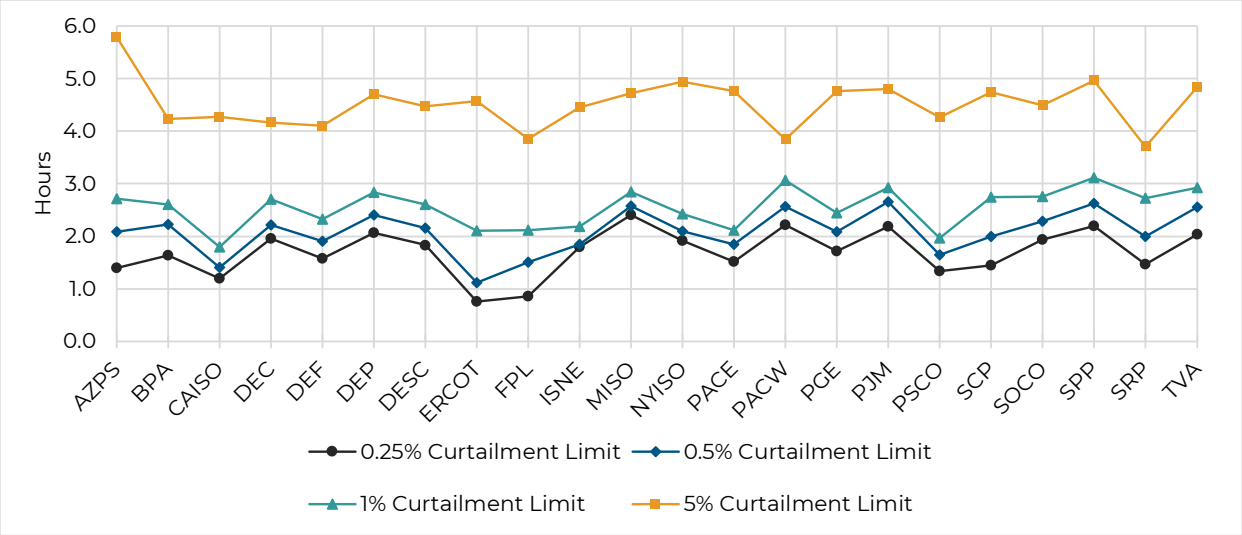
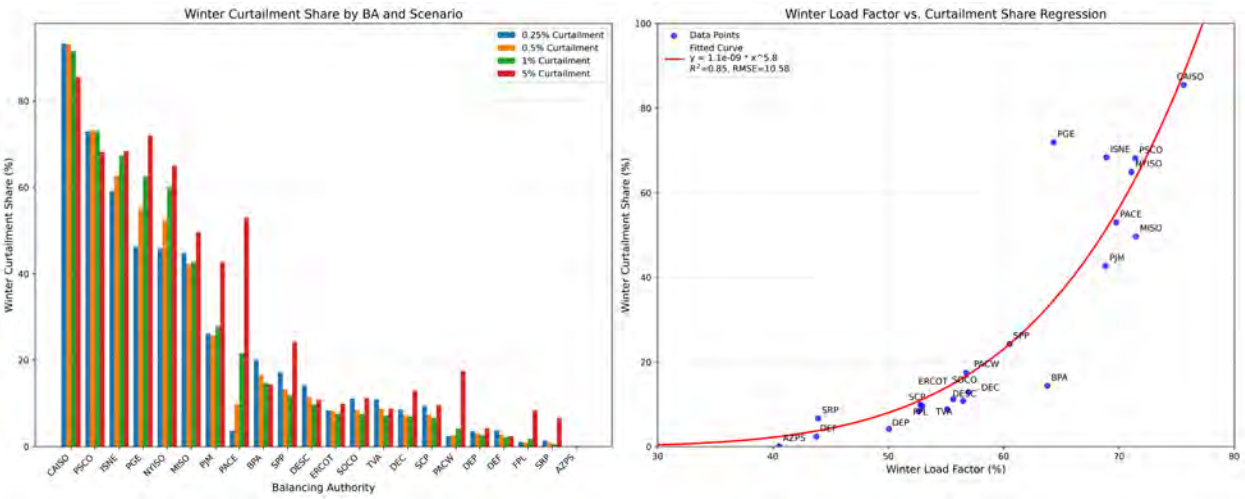


Figure 12. Seasonal Curtailment Analysis



(a) (b)

22 Note the remainder of the curtailment occurred in these BAs in shoulder months (i.e., not summer, not winter).

23 These values correspond to the seasonal curtailment concentration for the 1% curtailment limit.

A key observation is the strong correlation between the winter load factor (system utilization during winter months) and the seasonal allocation of curtailment hours (Figure 12b). BAs with lower winter load factors—indicating reduced system utilization during winter—tend to have greater capacity to accommodate additional load in winter while experiencing a dispro-portionately higher share of curtailment during summer months. This trend is particularly pronounced in balancing authorities located in the Sun Belt region, resulting in a lower win-ter concentration of curtailment hours.

While most BAs exhibited relatively stable seasonal curtailment shares across increasing load addition thresholds, some demonstrated notable shifts in seasonal allocation as load additions increased (e.g., PACW, FPL, NYISO, ISO-NE, PACE, PGE). These shifts highlight the dynamic interplay between system demand patterns and the incremental addition of new load.

Figure 12a illustrates this variability, showcasing the relationship between winter load factor and winter curtailment share across curtailment scenarios.[24]

Discussion

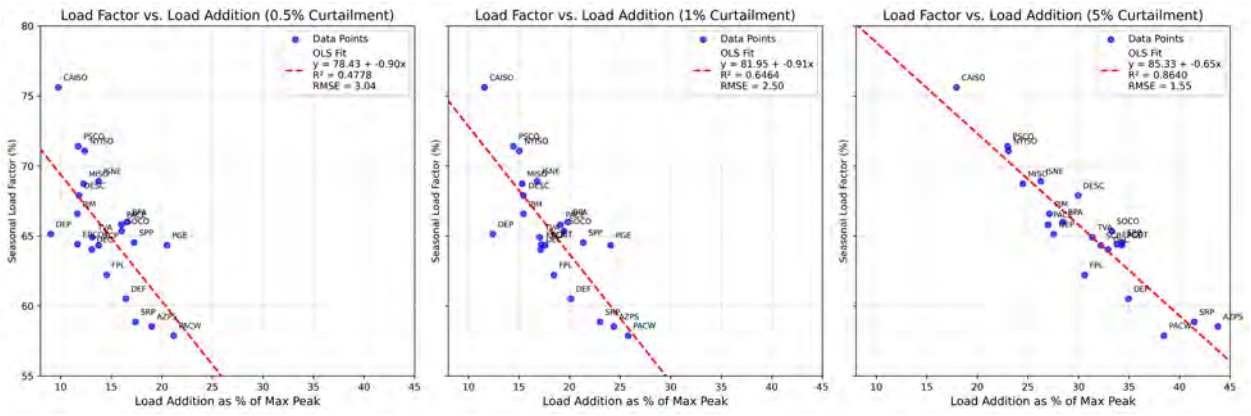
The results highlight that the significant headroom in US power systems—stemming from their by-design low load factors—could be tapped to enable the integration of substantial load additions with relatively low rates of load curtailment. They also underscore substantial variation in flexibility across balancing authorities, driven by differences in seasonal and aggregate load patterns. This variation suggests that seasonal load factors may be strongly linked to how much additional load a balancing authority can integrate without requiring high curtailment rates.

To explore this relationship, we analyzed system load factors in relation to the additional load that each balancing authority could accommodate while limiting the load curtailment rate to 0.5%, 1.0%, and 5.0% (i.e., the load curtailment limit). To allow for meaningful comparison across BAs, the additional load was standardized as a percentage of the BA's historical peak load. To account for whether a balancing authority's curtailment was concentrated in the summer or winter, the seasonal load factor was selected corresponding to the season with the highest share of curtailment.

The analysis revealed that BAs with higher seasonal load factors tended to have less headroom for the load curtailment limits examined (Figure 13). In simpler terms, systems with higher utilization during their busiest season had less power generation capacity planned to be available that could serve new load without hitting curtailment limits. For example, CAISO, with a seasonal load factor of 76%, could accommodate less additional load compared to PacifiCorp West (PACW) and AZPS, which exhibited lower seasonal load factors and supported larger load additions as a share of peak system load. This relationship grew in statistical significance as the load curtailment limit increased, yielding an R^2 value of 0.48 and an RMSE of 3.04 at the 0.5% curtailment limit, and an R^2 value of 0.86 and an RMSE of 1.55 at the 5% curtailment limit (i.e., 86% of the variation in load addition capacity across balancing authorities can be explained by differences in load factor at a curtailment limit of 5.0%).

24 Note in Figure 12b that a high-degree polynomial function captures the nonlinear growth in the area under the load curve as curtailed load exceeds a fixed peak threshold. This fit generally aligns with expectations, demonstrating that higher-degree terms are necessary to capture the relationship between load factor and curtailed load.

Figure 13. Load Factor Versus Max Load Addition as Share of Peak Load



These findings emphasize the importance of load factor as a predictor of curtailment-enabled headroom. BAs with more uneven peak seasonal demand—characterized by relatively low system utilization in winter or summer—tend to have greater capacity to integrate new loads with limited curtailment. Conversely, systems with more consistent demand across the winter and summer face tighter limits, as their capacity to absorb additional load is already constrained by elevated baseline usage.

Limitations

This analysis provides a first-order assessment of power generation capacity available for serving new curtailable loads, and hence is an exploration of the market potential for large-scale demand response. The primary focus of the analysis is to ensure that total demand, subject to curtailment limits for new load, stays below the system peak for which system planners have prepared. Other considerations important for planning—such as ensuring adequate transmission capacity, ramping capability, and ramp-feasible reserves, among others—are beyond the scope of this study and therefore the results cannot be taken as an accurate estimate of the load that can be added to the system. Additionally, the analysis assumes the new loads do not change current demand patterns but rather shift the existing demand curves upward, and a more precise assessment of the potential for integration of new loads would require detailed characterization of the temporal patterns of the load. There is significant variation in how system operators forecast and plan for system peaks, accounting for potential demand response, and as a result there will be differences in the methods used to estimate potential to accommodate new load. Despite these limitations, the results presented here signal a vast potential that, even if overstated, warrants further research.

On the other hand, some aspects of this study may have contributed to an underestimation of available headroom. First, the analysis assumes that each BA's maximum servable load in the winter and summer is equivalent to the BA's highest realized seasonal peak demand based on the available historical data. However, the available generation capacity in each balancing authority should materially exceed this volume when accounting for the installed reserve margin. In other words, system operators have already planned their systems to accommodate load volume that exceeds their highest realized peak. Second, the analysis removed outlier demand values in some BAs to avoid using unreasonably high maximum peak thresholds, which would understate the curtailment rates. However, if some of the removed outliers properly represent a level of system load that the system is prepared to serve reliably,

this analysis may have understated the curtailment-enabled headroom. Third, the analysis assumed all new load is constant and hence increases the total system load by the same gigawatt hour-by-hour, which would tend to overstate the absolute level of required gigawatt hour curtailment for a load that is not constant.

Future Analysis

Enhancing this analysis to more accurately assess the capacity to integrate large curtailable load would require addressing the following considerations:

Network Constraints

This analysis does not account for network constraints, which would require a power flow simulation to evaluate the ability of the transmission system to accommodate additional load under various conditions. As such, the results should not be interpreted as an indication that the identified load volumes could be interconnected and served without any expansions in network capacity. While the existing systems are planned to reliably serve their peak loads, this planning is based on the current load topology and the spatial distribution of generation and demand across the transmission network. A large new load could avoid exceeding aggregate peak system demand by employing flexibility, yet still cause localized grid overloads as a result of insufficient transmission capacity in specific areas. Such overloads could necessitate network upgrades, including the expansion of transmission lines, substations, or other grid infrastructure. Alternatively, in the absence of network upgrades, localized congestion could be addressed through the addition of nearby generation capacity, potentially limiting the flexibility and economic benefits of the new load. These factors underscore the importance of incorporating network-level analyses to fully understand the operational implications of large flexible load additions.

Intertemporal Constraints

This analysis does not account for intertemporal constraints related to load and generator operations. For load operations, response times affect system operations and management of operational reserves. Faster response times from flexible loads could alleviate system stress more effectively during peak demand periods, potentially reducing the reliance on reserve capacity. Conversely, slower response times may require additional reserves to bridge the gap between the onset of system imbalances and the load's eventual response. Moreover, the rapid ramp-down of large flexible loads could lead to localized stability or voltage issues, particularly in regions with weaker grid infrastructure. These effects may necessitate more localized network analyses to evaluate stability risks and operational impacts. On the generation side, intertemporal constraints such as ramping limits, minimum up and down times, and startup times can affect the system's ability to integrate fast-response demand. For instance, ramping constraints may restrict how quickly generators can adjust output to align with the curtailment of flexible loads, while minimum uptime and downtime requirements can limit generator flexibility.

Loss of Load Expectation

Peak load is a widely used proxy for resource adequacy and offers a reasonable indicative metric for high-level planning analyses. However, a more granular assessment would incorporate periods with the highest loss of load expectation (LOLE), which represent the times when the system is most likely to experience supply shortfalls. Historically, LOLE periods have aligned closely with peak load periods, making peak load a convenient and broadly

applicable metric. However, in markets with increasing renewable energy penetration, LOLE periods are beginning to shift away from traditional peak load periods. This shift is driven by the variability and timing of renewable generation, particularly solar and wind, which can alter the temporal distribution of system stress. As a result, analyses focused solely on peak load may understate or misrepresent the operational challenges associated with integrating large new loads into these evolving systems.

CONCLUSION

This study highlights extensive potential for leveraging large load flexibility to address the challenges posed by rapid load growth in the US power system. By estimating the curtailment-enabled headroom across balancing authorities, the analysis demonstrates that existing system capacity—intentionally designed to accommodate the extreme swings of peak demand—could accommodate significant new load additions with relatively modest curtailment, as measured by the average number, magnitude, and duration of curtailment hours.

The findings further emphasize the relationship between load factors and headroom availability. Balancing authorities with lower seasonal load factors exhibit greater capacity to integrate flexible loads, highlighting the importance of regional load patterns in determining system-level opportunities. These results suggest that load flexibility can play a significant role in improving system utilization, mitigating the need for costly infrastructure expansion and complementing supply-side investments to support load growth and decarbonization objectives.

This analysis provides a first-order assessment of market potential, with estimates that can be refined through further evaluation. In particular, network constraints, intertemporal operational dynamics, and shifts in loss-of-load expectation periods represent opportunities for future analyses that can offer a deeper understanding of the practical and operational implications of integrating large flexible loads.

In conclusion, the integration of flexible loads offers a promising, near-term strategy for addressing structural transformations in the US electric power system. By utilizing existing system headroom, regulators and market participants can expedite the accommodation of new loads, optimize resource utilization, and support the broader goals of reliability, affordability, and sustainability.

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ABBREVIATIONS

AI	Artificial intelligence
AZPS	Arizona Public Service Company
BA	balancing authority
BPA	Bonneville Power Administration
CAGR	compound annual growth rate
CAISO	California Independent System Operator
CLRs	controllable load resources
CPUs	central processing units
DEC	Duke Energy Carolinas
DEF	Duke Energy Florida
DEP	Duke Energy Progress East
DERs	distributed energy resources
DESC	Dominion Energy South Carolina
EIA	Energy Information Administration
EPRI	Electrical Power Research Institute
ERCOT	Electric Reliability Council of Texas
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission's
FPL	Florida Power & Light
GPUs	graphics processing units
ICT	information, and communication technology
ISO-NE	ISO New England
LGIA	Large Generator Interconnection Agreement
LOLE	loss of load expectation
MISO	Midcontinent Independent System Operator
NYISO	New York Independent System Operator
PACE	PacifiCorp East
PACW	PacifiCorp West
PG&E	Pacific Gas and Electric
PGE	Portland General Electric Company
PJM	PJM Interconnection
PSCO	Public Service Company of Colorado
RMSE	Root mean square error
RTO/ISO	Regional transmission organization/independent system operator
SCP	Santee Cooper, South Carolina Public Service Authority
SEAB	Secretary of Energy Advisory Board
SLAs	service-level agreements
SOCO	Southern Company
SPP	Southwest Power Pool
SRP	Salt River Project Agricultural Improvement and Power District
TPU	tensor processing unit
TVA	Tennessee Valley Authority

APPENDIX A: CURTAILMENT-ENABLED HEADROOM PER BALANCING AUTHORITY

Figure A.1. Curtailment Rate Versus Load Addition by RTO/ISO, MW

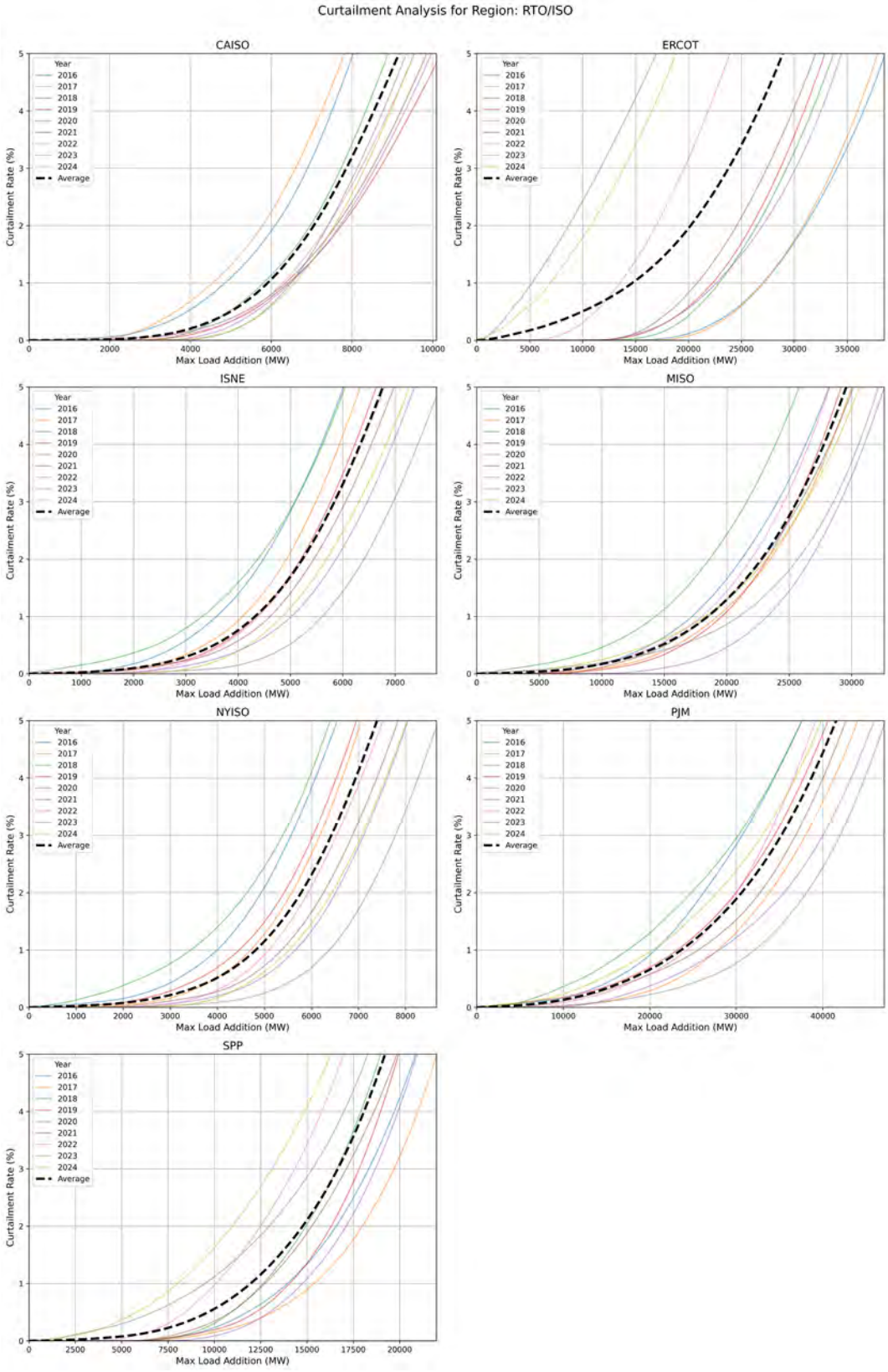


Figure A.2. Curtailment Rate Versus Load Addition by Non-RTO Southeastern Balancing Authority, MW

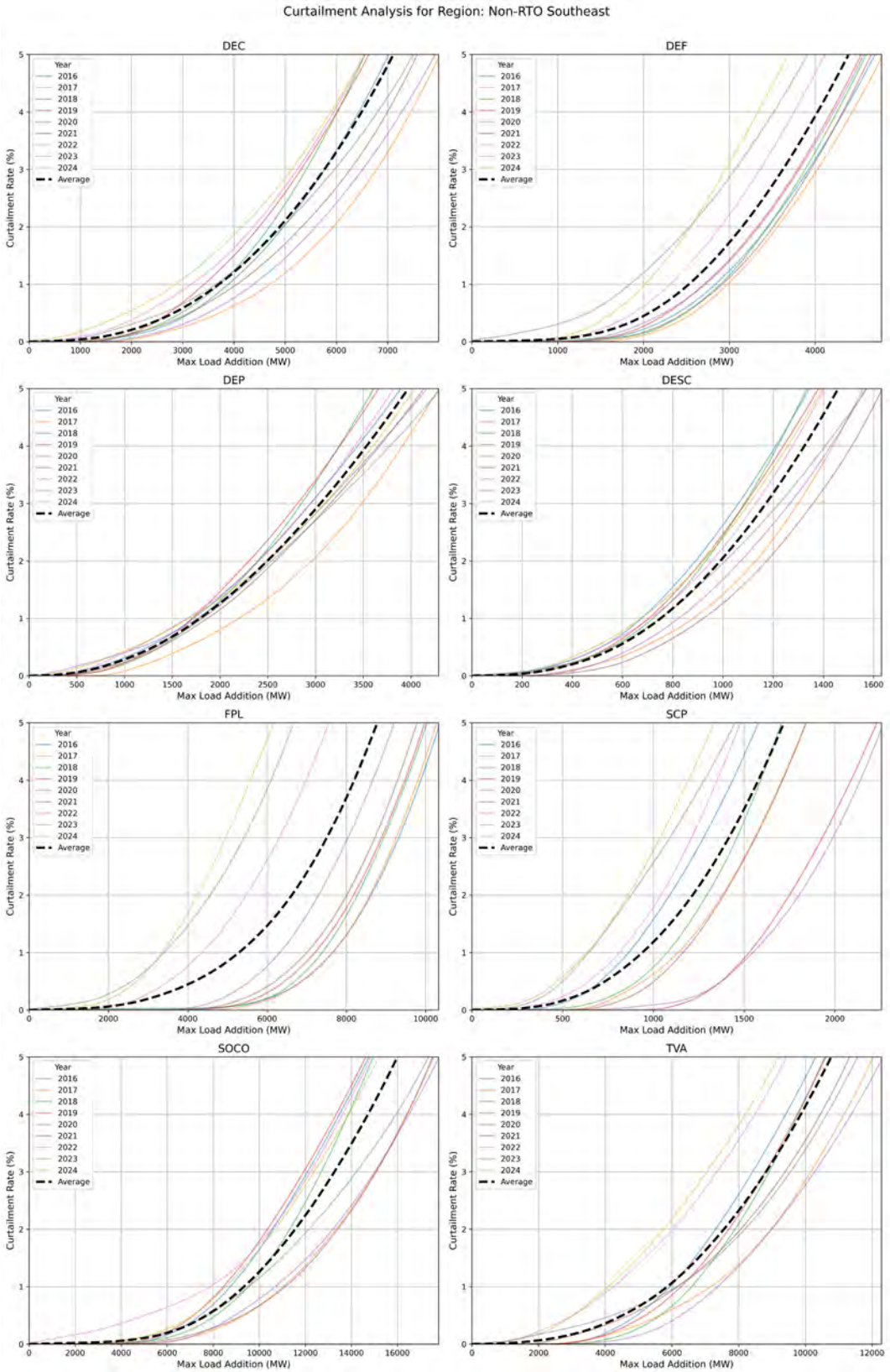
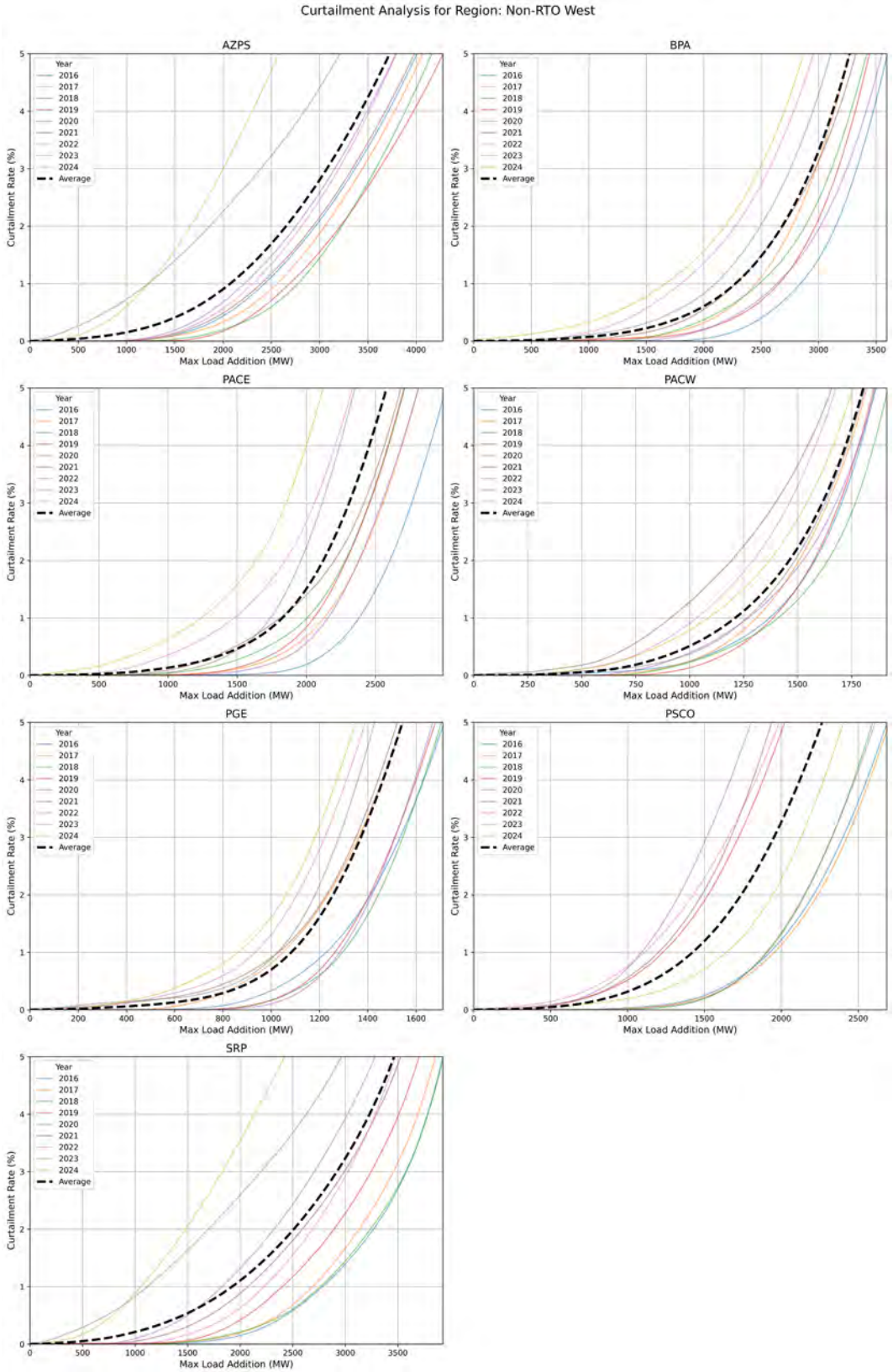


Figure A.3. Curtailment Rate Versus Load Addition by Non-RTO Western Balancing Authority, MW



APPENDIX B: DATA CLEANING SUMMARY

The data cleaning process attempted to improve the accuracy of nine years of hourly load data across the 22 balancing authorities, including the following steps:

1. Data normalization
    - **Dates:** Date-time formats were verified to be uniform.
    - **Demand data:** Where the balancing authority had an "Adjusted demand" value for a given hour, this value was used, otherwise its "Demand" value was used. The final selected values were saved as "Demand" and a log was kept.
    - **BA labels:** Labels were mapped to align with widely used acronyms, including:
        - CPLE → DEP
        - DUK → DEC
        - SC → SCP
        - SWPP → SPP
        - SCEG → DESC
        - FPC → DEF
        - CISO → CAISO
        - BPAT → BPA
        - NYIS → NYISO
        - ERCO → ERCOT
2. Identifying and handling outliers
    - **Missing and zero values:** Filled using linear interpolation between adjacent data points to maintain temporal consistency.
    - **Low outliers:** Demand values below a predefined cutoff threshold (such as 0 or extremely low values inconsistent with historical data) were flagged. Imputation for flagged low outliers involved identifying the closest non-outlier value within the same balancing authority and time period and replacing the flagged value.
    - **Spikes:** Sudden demand spikes that deviated significantly from historical patterns were flagged. Corrections were applied based on nearby, consistent data.
    - **Erroneous peaks:** Specific known instances of demand peaks that are outliers (e.g., caused by reporting errors) are explicitly corrected or replaced with average values from adjacent time periods.
3. **Data validation**:
    - Seasonal and annual peak loads, load factors, and other summary statistics were computed and inspected to ensure no unexpected results. Max peaks were compared to forecasted peaks collected by FERC to ensure none were out of range.
    - Logs summarizing corrections, including the number of spikes or outliers addressed for each balancing authority, were saved as additional documentation.

APPENDIX C: CURTAILMENT GOAL-SEEK FUNCTION

Mathematically, the function can be expressed as

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{Curtailment_y(L)}{L \cdot 8{,}760}\cdot 100\right) = CurtailLimit$$

where

L	=	load addition in MW (constant load addition for all hours)
N	=	total number of years in the analysis (2016–2024)
$Curtailment_y(L)$	=	curtailed MWh for year y at load addition L
$L \cdot 8{,}760$	=	maximum potential energy consumption of the new load operating continuously at full capacity
$CurtailLimit$	=	predefined curtailment limit (e.g., 0.25%, 0.5%, 1.0%, or 5.0%).

For each hour t in year y, the curtailment is defined as

$$Curtailment_t(L) = \max(0, Demand_t + L - Threshold_t)$$

where

L	=	load addition being evaluated in MW
$Demand_t$	=	system demand at hour t in MW
$Threshold_t$	=	seasonal peak threshold applicable for hour t in MW (i.e., the maximum winter or summer peak across all years)

These hourly curtailments are aggregated to find the total annual curtailment

$$Curtailment_y(L) = \sum_{t \in T_y} Curtailment_t(L)$$

where

T_y	=	all hours in year y.

Replacing $Curtailment_y(L)$ in the original formula, the integrated formula becomes

$$\frac{1}{N}\sum_{y=1}^{N}\left(\frac{\sum_{t \in T_y}\max(0, Demand_t + L - Threshold_t)}{L \cdot 8{,}760} * 100\right) = CurtailLimit$$

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-44:
RMI Analysis of Coal Plants' Threats to Reliability



Reality Check: We Have What's Needed to Reliably Power the Data Center Boom, and It's Not Coal Plants

A range of clean, resilient solutions can help us meet the electrical needs of our growing digital economy while saving Americans money.

August 12, 2025

By Gabriella Tosado, Ashtin Massie, Joe Daniel

After decades of relatively flat electricity demand, the US power sector is expecting demand to grow due, in large part, to new data centers. These energy-intensive facilities are reshaping the grid, with some utilities now projecting over 20 percent load growth by 2035. In places like Virginia, which constitutes 13 percent of all reported data center capacity globally and 25 percent of the data center capacity in the United States, data centers already account for over a quarter of some utilities' total electric demand, and their footprint is only growing.

The myth

Utilities are struggling to maintain accurate forecasts and identify resources that can meet this growth. There is a high-profile effort to keep coal plants that are set to retire online and run them at unprecedented levels, ostensibly for reasons of reliability. But the truth is, coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

> Coal-fired power plants, far from being a reliable backbone for this new era of electricity demand, are a brittle, outmoded technology that threatens to undermine the very grid resilience they're being proposed to protect.

Tweet

Reality #1: Aging coal plants are failing to consistently deliver under stress

Coal plants face a fundamental constraint: they are aging and increasingly unreliable. Most of the coal fleet was built in the 1970s and 1980s, and years of wear and tear have led to a rise in unplanned outages. In many cases the sheer cost to maintain and modernize these plants did not make sense with the availability of more reliable and affordable alternatives – and that's still the case.

According to the Energy Systems Integration Group (ESIG) *Ensuring Efficient Reliability* report, a coal plant's capacity accreditation, or the amount of time it can contribute to peak demand, is only 83 percent when adjusted for real-world performance. PJM also has capacity accreditation of coal plants at 83 percent and some plants fare even worse. Gridlab's reliability study found Colstrip, a large regional coal plant in Montana, operating with a capacity accreditation of only 54 percent – meaning it's effectively unavailable nearly half the time it's needed.

Extreme weather exacerbates these vulnerabilities. Cold snaps, heat waves, and storms have all exposed coal's fragility during grid stress events. Reliability is not just about being dispatchable, it's about delivering performance under stress. Coal plants struggle to do that consistently. For coal plants to truly meet the constant demands of data centers, they would need to run at high-capacity factors and avoid major outages, all of which fly in the face of current performance trends. If a large coal plant trips offline while supporting a cluster of data centers,

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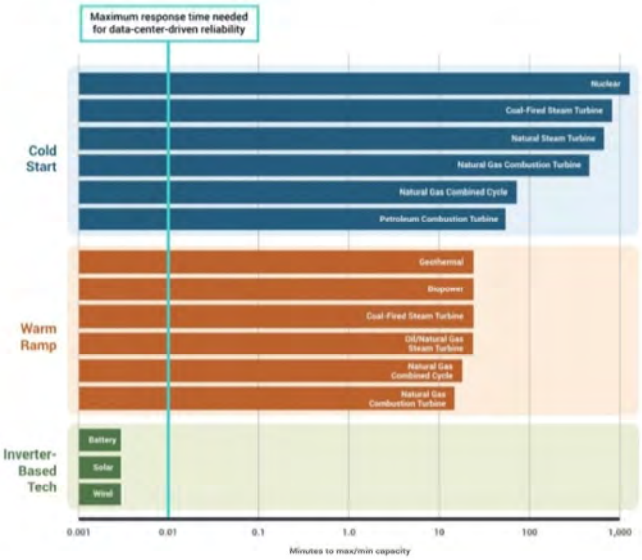
the sudden loss of supply could lead to cascading failures across the grid. This is because generation must equal load at all times, datacenter or no datacenter. As a result, relying on coal plants to support these high-density digital loads doesn't enhance reliability, it endangers it. And it's not a matter of *if* the coal plant will fail, but *when*.

Reality #2: The inflexibility of coal plants risks grid stability

Coal boosters often point to the "always-on" nature of coal plants as evidence of their reliability. But that characteristic is a liability, not a strength, when it comes to supporting large, fast-changing loads like data centers. Coal units are inherently inflexible: they ramp slowly, respond poorly to sudden load shifts, and are difficult to turn on or off quickly. This rigidity is a poor match for the dynamic and often unpredictable nature of data center demand. Further, inflexible coal plants can worsen grid congestion; by occupying limited transmission capacity with inflexible generation, they prevent cheaper or cleaner resources from being delivered. This issue has already been flagged by **independent market monitors** in regions like MISO – which covers 15 US states and a Canadian province – where congestion-related market distortions have cost **over $1 billion a year**. Coal plants displace faster-responding resources that are better suited to follow load. And the stakes are high.

As noted by the North American Electric Reliability Corporation (NERC), large, voltage-sensitive loads like data centers require flexible, responsive grid solutions, not slow-ramping generators that can take 12 or more hours to come online. NERC's recent ***Incident Review and Guidance on Voltage-Sensitive Large Load Integration*** describes an event in 2024 where a transmission fault triggered a sudden disconnection of 1,500 megawatts of voltage-sensitive data center load, leading to sharp frequency and voltage spikes that required operator intervention. The incident exposes the system's vulnerability to instability when inflexible generation cannot respond to large load fluctuations.

Minutes needed for a power plant to reach max/min capacity



If a data center either loses access to load or goes offline rapidly, a grid's generation needs to respond at sub-second speeds. The average coal plant ramp rate is **4 percent per minute** which translates to spending over 20 minutes to respond to a large load event. From a cold start, the average coal plant would take over **12 hours** to reach max capacity. Coal plants simply can't respond fast enough to support the reliability needs of modern data centers. Whether it's the hours-long startup time from a cold state or sluggish ramp rates to turn off, these plants are too slow to provide the real-time flexibility required during sudden load changes or outages.

Reality #3: Clean resources are available now that can better respond to and support data centers for less

The good news is that we don't need to rely on brittle coal plants to meet the needs of a digital economy. A range of cleaner, more resilient solutions is already available – and scalable. For example, we recently found that **more than 95 percent** of future demand can be met with fast, scalable, and clean solutions:

Shares

Alternative near-term solutions to meet load growth

Technology	Opportunity
Energy Efficiency	Over 50 GW of energy efficiency can be deployed – by both creating programs for new loads and expanding existing programs aligned with system needs. Energy efficiency can unlock benefits beyond system cost savings, improving comfort and resilience in homes.

Virtual Power Plants	60 GW of virtual power plants can be deployed by 2030, with programs stood up and enrolled in under 6 months. Policymakers in Virginia recently passed a bill that requires 450 MW of VPPs deployed rapidly to meet growing demand.
Advanced Transmission Technologies	Grid enhancing technologies and reconductoring can unlock over 80 GW of incremental peak capacity by reducing transmission and interconnection constraints. Lawmakers in New Mexico passed a bill requiring utilities to assess the use these technologies in plans to get more out of the existing grid.
Clean Repowering	There is 14 GW of fossil-fuel generation expected to retire, that could serve as sites for quick addition of new renewable energy and storage while reducing system costs. Market operators like PJM are enabling clean repowering by updating rules to allow for surplus interconnection.
Power Couples	New load can be co-located with renewable energy at the site of existing, underutilized generators with approved interconnections—a strategy which we call "Power Couples." There is over 30 GW of opportunity to deploy Power Couples under $100/MWh, and over 50 GW of opportunity under $200/MWh.

Coal plants are a legacy technology, not a solution for the future. Coal plants' operational characteristics make them less suited to meet the scale and speed of these new challenges. The path forward is not about discarding the past, but about building on it with cleaner, more adaptable resources that can reliably serve evolving grid needs.

Technologies like battery storage, demand flexibility, and clean energy portfolios offer practical, cost-effective options that align with modern load dynamics. As we noted in a recent **article**, by running coal plants only when it is economical to do so and using the extra transmission headroom that creates to reinvest with clean energy upgrades, our grid can support the next wave of economic growth with the flexibility it demands. There are reasons to manage the shift to new, clean resources **thoughtfully and intentionally**, but propping up coal plants that are not suited for the job is a step in the wrong direction.

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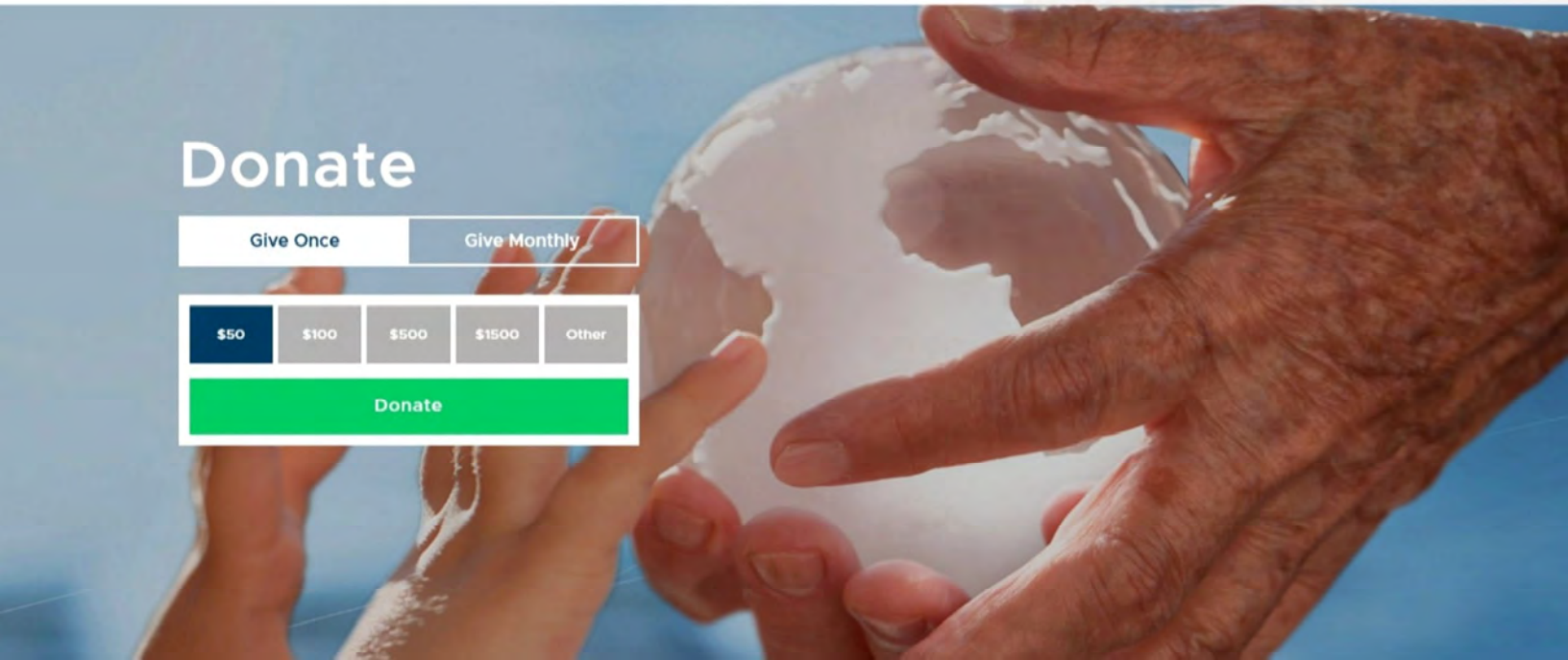

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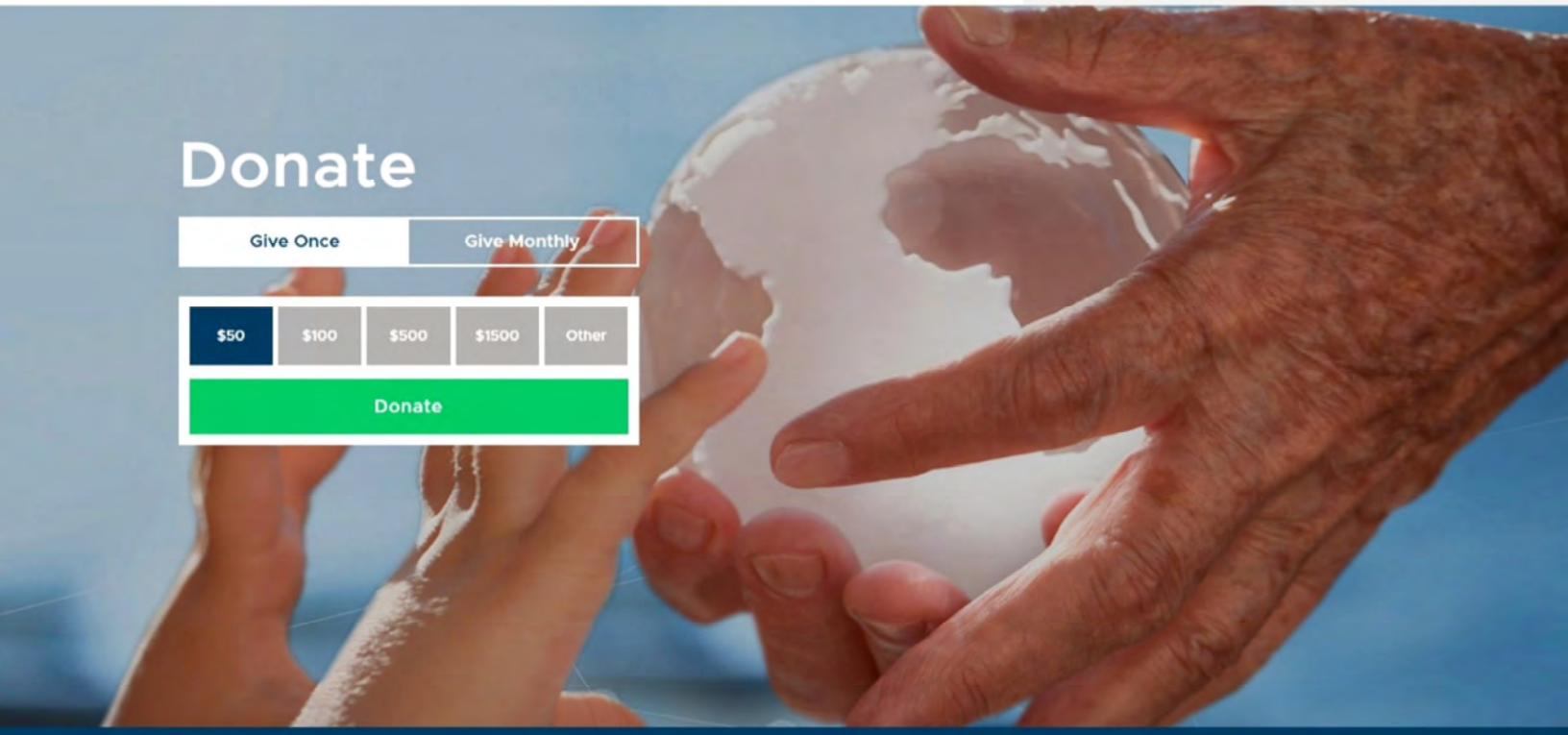

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Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
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Exhibit 2-45:
Energy Innovation Report



ENERGY INNOVATION
POLICY & TECHNOLOGY LLC®

DODGING THE FIRM FIXATION FOR DATA CENTERS AND THE GRID

Eric G. Gimon

Senior Fellow, Energy Innovation

November 2025

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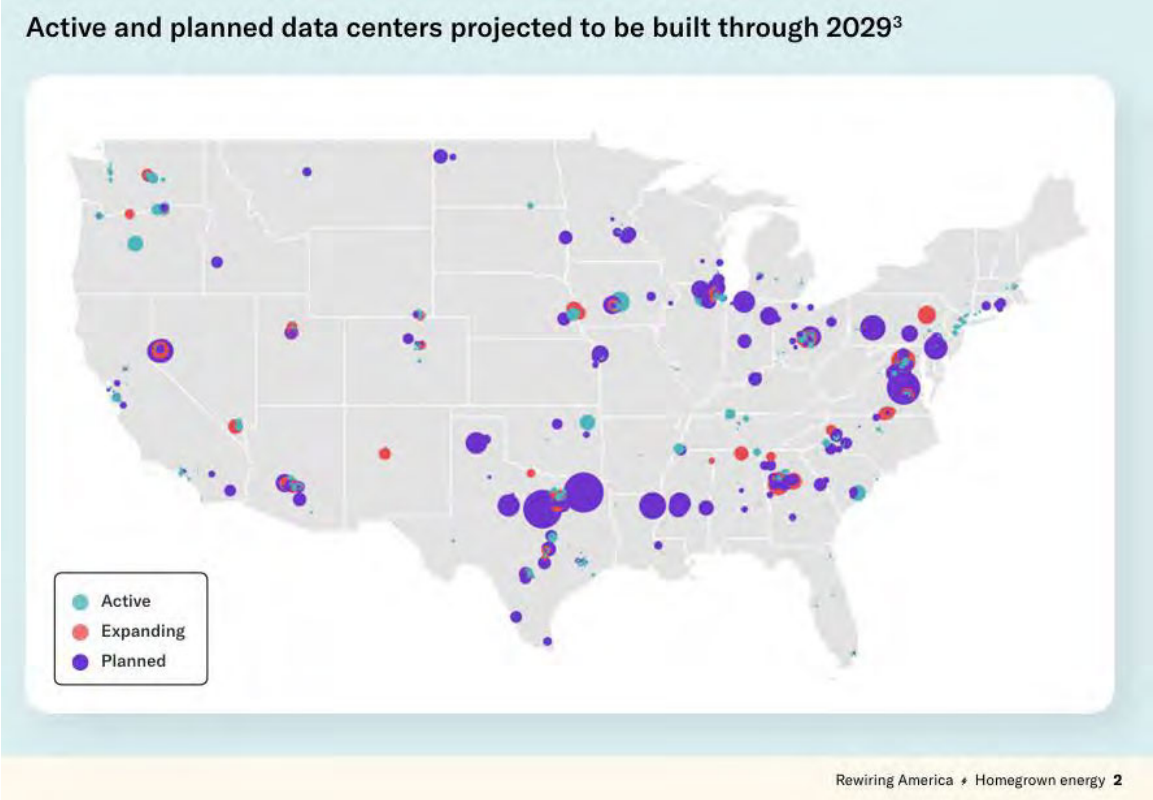
EXECUTIVE SUMMARY

In multiple states[1,2] (see Figure 1) massive new data center campuses and a coterie of smaller ones have reversed years of flat or declining electricity demand, leaving utilities and policymakers scrambling for solutions.

Figure 1 Existing and Projected data centers from Rewiring America's "Homegrown Energy" report[3].



Faced with this onslaught of new demand, many utilities and developers are depending on old habits by adding new gas plants, refurbishing coal units, or turning to nuclear partnerships along with extensive grid upgrades near new load centers – the "firm fixation."

It reflects a belief that only firm resources and major transmission upgrades can handle data centers' needs. Yet this approach overlooks two essential truths: (1) power plants and data centers are both parts of a larger, interconnected system, and (2) data center loads, especially those driven by artificial intelligence (AI), are far more dynamic than the flat, baseload profiles they are often assumed to be. Firm fixation leads utilities and regulators to default to outdated firm-generation solutions instead of modern, modular approaches that consider the full complexities of today's power grid. At the scale of even the most compact new data centers, connecting to the grid is no small matter.

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Regardless of approach, three features of recent growth are well known to the electricity industry and policy community, and to some extent the wider public. First, new data center load is being amplified by extreme investment interest in AI. Second, incremental load tends to be highly concentrated due to the nature of the growing individual server need for power and the geographic concentration of data centers. Third, the data center industry's appetite for new growth is so large, and other facility capital costs so high that new project owners are willing to pay more for power than average existing electricity consumers.

In a 2024 brief, Energy Innovation proposed instead that a portfolio of solutions – clean energy portfolios, advanced transmission technologies, demand-side flexibility, and efficiency – could work together to obviate the need to rush to meet demand with new fossil generation.[4] Reality so far has deviated significantly from this vision, setting up the power sector for failure: Either new demand will not be met or the negative cost and performance impacts of doing so on other grid users will challenge electricity markets and other long-standing arrangements in a dangerous manner.

The mad scramble to meet data center demand using traditional but crude resource investment methods can create potential missed opportunities to manage load growth that come from a deeper understanding of data centers. Of course, their electricity demand is problematic because it is concentrated, growing fast, and willing to outspend other users. However, it is also far more complex than the flat, 24/7 block it is often assumed to be. This primer identifies six defining features that provide a more nuanced version picture of data centers:

- **Agency and Split Incentives** – Multiple actors (developers, operators, and tenants) and ownership or usage types of data centers create a divided responsibility over grid interaction and access to energy-saving incentives that complicates energy decisions.
- **Clustering** – Facilities tend to concentrate geographically, amplifying local grid stress and transmission costs while creating systemic planning challenges.
- **Consumption Profiles** – Loads are not 24/7 blocks. Instead, they are choppy, with swings of hundreds of megawatts over short intervals, undermining assumptions of steady baseload behavior and potentially affecting the stability of the grid if safeguards are not put in place.
- **Flexibility** – While some AI-driven workloads can be scheduled for off-peak hours, this flexibility is uneven across facility types and even within users in the same data center campuses. While modest levels of curtailment or load-shifting based demand response during peak hours could ease interconnection bottlenecks and peak demand requirements, these may work best in combination with battery energy storage to overcome split incentives and other complexities.

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- **Backup Requirements** – Current reliance on diesel for backup generation is unsustainable. Batteries and longer-duration storage are cleaner, more scalable options that provide knock-on benefits for the grid if allowed to participate as both backup and demand response.
- **Modularity** – Data centers grow in phases just as demand grows in phases rather than all at once, aligning poorly with "lumpy" firm large one-time investments in dispatchable power plants and infrastructure upgrades, while fitting well with modular renewables and battery deployments.

When examined as a whole, these features undermine the firm fixation logic. One-to-one matching of data centers with dedicated or "captive" firm power plants is particularly unwise for both the power generator and the new data centers, even given their willingness to pay for speed-to-power. Relying on captive plants for all supply such as pairing a nuclear plant with a large data center exposes them to outages, inflexibility, and stranded-asset risks, while hybrid co-location deals still rely heavily on the broader grid.

Most new demand will need to be served fully or in-part through the bulk power system, requiring upgrades in three key areas: **connection infrastructure, grid services (especially peak capacity), and bulk electricity supply.**

Once this is established, it's clear that data centers can tap the grid's advantages as a "system of systems" that pools variable demand and generation resources solutions together and ensures supply and demand match in real-time. As peak demand rises, this crucial service must be met, but not necessarily by firm generation. A deeper understanding of data center demand attributes yields a more complete solution set which includes data center flexibility, onsite storage, portfolios of clean energy, and others.

The challenges data centers pose include lengthy interconnection queues, peak stress, price impacts, and rising emissions – but these are not insurmountable. Three core lessons emerge for policymakers and stakeholders:

- The process of connecting any new **large load is a key leverage point.** It is the moment to ensure consumption tariffs reflect cost causation, encourage flexibility, and align incentives without imposing unworkable burdens later. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the full costs of the infrastructure they trigger, and to nudge data center developers towards solutions such as flexible demand or local storage that relieves local bottlenecks and supports the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

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- **Demand side is a resource hiding in plain sight**. Household electrification and distributed resources can free up tens of gigawatts (GW) at costs comparable to new gas plants and on a faster timetable, offering a more pragmatic and equitable path to integration. Yet at the state and regional level, policy innovation still lags behind. However, several widespread mechanisms exist to channel data center owners and operators' willingness to pay into new solutions that help other existing customers accommodate rapid data center load growth in a fair, fast and equitable way. Because grid connection bottlenecks can be managed by multiple possible combinations of diverse resources, data centers don't need to do all the work of mitigating their grid impacts onsite or through a single counterparty. Once a data center has invested in flexibility and equipment to resolve local connection issues, additional constraints such as upstream transmission and grid services bottlenecks as well as large incremental amounts of annual electricity delivery can be addressed with demand-side solutions from other grid users. A recent report from Rewiring America proposes that many of the resources needed to meet data center load growth could come from sponsoring household upgrades instead of new generation.[5]
- **Storage and flexibility deliver a two-for-one win.** Batteries and managed demand not only ease all manner of data center impacts but can also accelerate renewable integration, providing cleaner, faster, and cheaper capacity than firm fossil solutions. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—a two-for-one advantage. Furthermore, these renewable-plus-battery solutions can capitalize upon existing surplus interconnection to more quickly connect data centers to the grid in co-located arrangements.

This report challenges the electricity and data center industries to move beyond a firm fixation and adopt solutions that leverage the full capabilities of modern power systems.

The next section describes six defining features of data centers: agency, clustering, consumption profile, flexibility, backup needs, and modularity. We then pivot to explaining why traditional firm responses fall short within the broader context of how the modern grid supplies power to consumers, especially large, new consumers. We will look at how new, modular solutions can meet digital demand more effectively. These steps will depend on a more nuanced understanding of data centers, as opposed to how they are often imagined.

Our hope is that this information will empower policymakers to make wiser decisions when faced with AI growth and proposed public investments, avoiding a firm fixation on simplistic approaches and reaching for more realistic answers that embrace the full complexities of the challenge that rapid data center load growth presents today. By moving beyond simplistic assumptions, policymakers can avoid overcommitting to

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outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. We want to leave policymakers with three key takeaways to avoid falling into a firm power matching fallacy and to instead embrace the ability to mix and match resources to meet data center needs.

What began as a major strain on the grid can become the catalyst for building a smarter one, supporting both the digital economy's explosive growth and the clean energy transition.

COMMERCIAL AND INDUSTRIAL REALITIES THAT APPLY TO DATA CENTERS

Actual data centers are not the simple "flat 24/7 block of demand" people imagine.

Six different demand features of data centers explain the diversity of data center types (agency, clustering, and profile) and their internal workings (flexibility, backup, and modularity).

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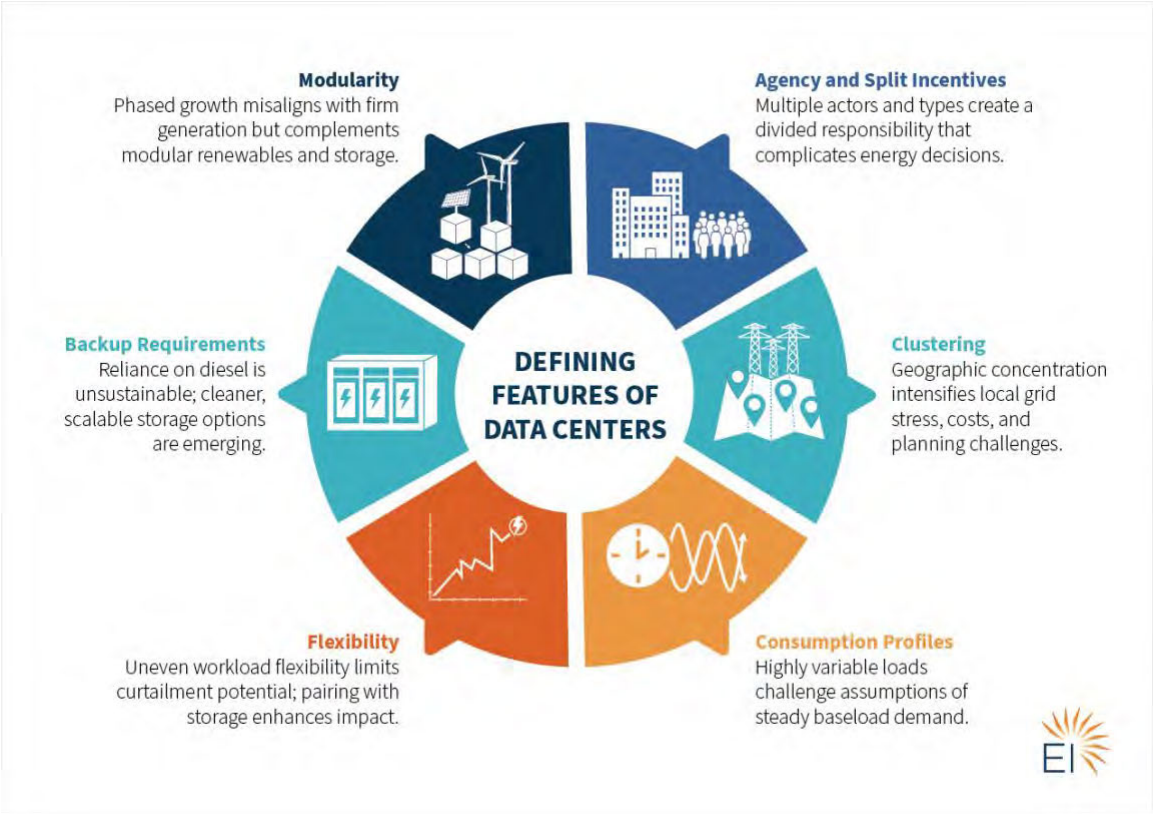
Figure 2 Actual data centers are not the simple "flat 24/7 block of demand" people imagine.



Data Center Feature 1: Agency and the split-incentive problem

Planning *and* operating *a data center* involves many decision-makers. *Some data centers (often called co-locations or "colos") are facilities where customers can rent space to house their servers and equipment or just run their software on provided equipment. This means the facility is developed and owned by a different company* from those *that rent rack space, buy* computing *capacity, and ultimately consume electricity. Multiple actors force complicated decisions around electricity supply.*

If we want new data centers to adapt their development approach to better integrate with the grid and increase their "speed-to-power," policymakers must understand the planning, construction, and operation of modern data centers. Many different actors are involved, creating a classic split-incentive problem. Loosely speaking, apart from the users or clients, three groups of actors dictate the energy and resource impacts of data centers: developers, facility operators, and service providers. These tend to be separate entities. Overlap sometimes occurs, but usually not enough to prevent split-incentive

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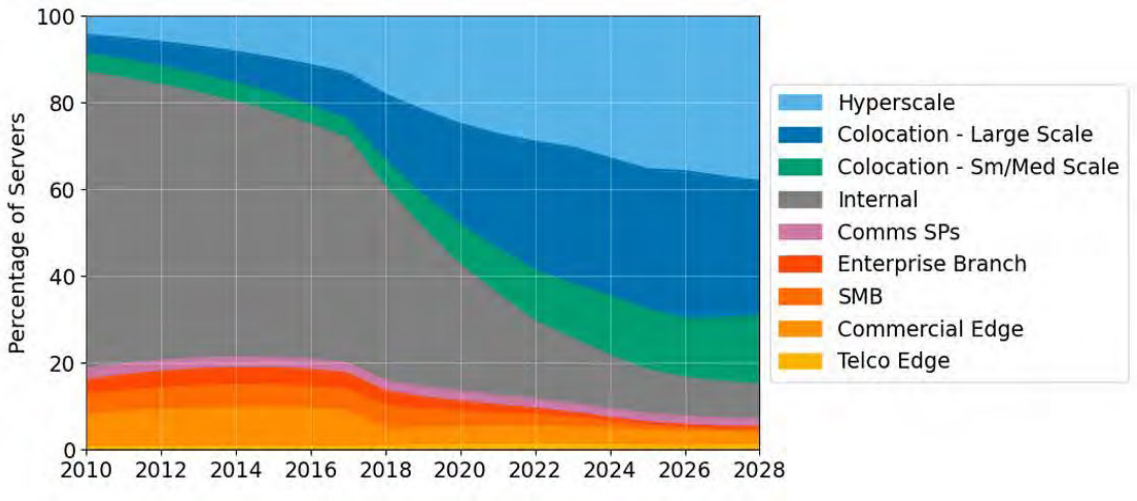
issues. More than half (and an even larger fraction of the current pipeline)[6] of data centers are categorized as co-location facilities—large facilities that rent out space to multiple separate entities.

Figure 3 Distribution of server types by data center type. 2024 United States Data Center Energy Usage Report[7]



We illustrate the split incentives by cataloguing some of the key concerns for each of the three types of decision-makers in the life of a data center. In early stages, data center development is mostly a real estate bet: developers acquire land, water, and electric connection rights and then these rights pass on to the projects they sell. The natural incentive for developers is to keep the range of future owners they could sell to as wide as possible. Hence, they are unlikely to want to enter contracts or agreements (or support legislation) that might prematurely impair any of the land, water, and power consumption rights for their projects. For example, they may not want to agree to be a flexible consumer in return for faster interconnection (load interconnection currently takes three to 11 years) because that might scare off some prospective buyers.

Similarly, owner/operators that lease capacity to data centers customers do not necessarily have much insight into how flexible these customers are or how their customers' usage pattern might change over time. They are conservative about aspects such as whether the tenant-user would be interested in avoiding on-peak usage, participating in time-varying rates, accessing clean energy tariffs, or participating in a demand-response program. Obviously, renters must abide by some rules (via master service agreements or service-level agreements[i]) about behavior that impacts power quality (voltage, frequency, harmonics, transients, etc.) or broader

[i] A master service agreement is an umbrella standardized contractual framework between a utility and the "customer of record" (which could be a data center owner/operator, a tenant/end-customer, or a special purpose entity created to hold the contract) across multiple facilities in the utility's territory. A load serving agreement is more specific to power delivery at a given site.

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electrical concerns (like grounding, interference, and surge protection), but that still leaves a lot of uncertainty for the data center owner/operator. Violations may also pass undetected until a severe problem occurs.

Because data centers are also large electricity consumers, utilities will want to know if contracts are backed by the ultimate users (e.g., hyperscalersii) or an intermediate company that could go bankrupt or disappear. Grid investments involve assets with multi-decadal lifetimes, while the service life of cutting-edge chips can be two to three years. Utilities and their regulators have a strong interest in recovering any incremental costs of investments needed to serve data centers and will look for contractual arrangements to make this happen.

Data Center Feature 2: Clustering, data centers are attracted by similar conditions or to each other

Data center locations tend to be concentrated in a few regions rather than evenly distributed. This clustering amplifies stress on already energy-dense grids. The main drivers are favorable conditions—reliable power, dense fiber, skilled workforce, tax regimes, and land—but anchor investments by hyperscalers or AI campuses could also accelerate the process. Policymakers should avoid treating projects as one-offs and consider the likelihood of a single facility snowballing into a larger cluster.

"Clustering" describes how data centers in the U.S. tend to collect in a handful of regions rather than being evenly distributed. Clustering creates stress for the bulk power system because it takes already energy-dense loads and adds even more load nearby. The easiest explanation for clustering is that it derives from favorable existing conditions: reliable electricity, dense fiber connectivity, neighboring trained workforce, supportive tax regimes, and land availability.

Large anchor projects also draw in more data center development: Once a hyperscaler or AI training facility establishes itself, it signals viability, brings new infrastructure, and lowers costs for additional entrants. Policymakers wanting to provide support for a big project by promises of jobs and tax revenue, risk underestimating the impacts of this attractive force as welcoming one project may quickly lead to a cascade of follow-on facilities, with both outsized benefits and mounting strains.[8]

Recent history reveals a pattern whereby anchor investments amplify favorable local conditions into enduring centers of digital infrastructure. Northern Virginia's "Data Center Alley" grew from early fiber and internet exchange into the world's largest concentration of data centers. Amazon Web Services (AWS) was an early and steady

---

[ii] A hyperscaler is a cloud service provider or operator that builds and manages massive data center networks supporting millions of virtual servers and petabytes of data, operating globally and designed to scale seamlessly across regions. Examples might include Amazon Web Services (AWS), Microsoft Azure, Google Cloud Platform (GCP), Meta (Facebook), Apple, Alibaba Cloud, and Tencent Cloud.

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investor in this cluster.[iii] Today, Data Center Alley reportedly handles roughly ~70 percent of the world's internet traffic, contains over 12 million square feet of commissioned data center space, and sustains hundreds of megawatts of power load.[9]. Reno's Tahoe-Reno Industrial Center became a global hub after Switch and Apple established major campuses, followed by Google and others[10]. Central Ohio offers a newer case: Google and AWS each invested in major builds, quickly attracting colocation providers.[11]. Atlanta and Phoenix look to be on similar paths[12].

In theory, diverse types of data centers should reinforce these patterns. Colocation facilities are drawn to network-dense hubs where they can maximize interconnection to other facilities. For example, enterprise servers might want to easily connect to multiple cloud providers—providers of cornerstone internet services stand to benefit from the reduced latency proximity affords, especially for content delivery like streaming video and games and so on. Hyperscalers could function as anchors, just like a department store in a shopping mall, investing billions into single campuses that create the vendor ecosystems others rely on. However, AI-focused facilities, with their unprecedented power needs, can also reshape the landscape by displacing other data centers competing for the same power network and generation resources.[13]

Electric power infrastructure both attracts and is stressed by clustering. Access to transmission lines and substations is a prerequisite, but as clusters grow, demand can overwhelm grids. Northern Virginia now faces multi-year waits for new hookups[14]. Reno's growth has raised water concerns and left Nevada utilities facing a potential doubling in necessary electrical infrastructure (also spurring them toward large renewable additions)[15]. Ohio illustrates the stakes most vividly: By March 2023, the utility AEP Ohio imposed a moratorium on new data center service agreements in Central Ohio, pending further study citing grid strain. Eventually regulators approved a new tariff[16] requiring data centers to pay for 85 percent of subscribed capacity whether it is used or not, with penalties for cancellation or under-performance and a four-year on-ramp[iv]. Clustering behavior can easily outrun planning and force regulators into reactive steps, introducing delays before more pro-active policies and tariffs can be put in place.

The policy lesson is not to avoid clusters—after all, they bring new jobs, tax revenue, and digital infrastructure—but to keep a skeptical eye on benefits claimed by developers and focus on smart planning. This should consider the multiple interests of stakeholders affected by a data center cluster and work in advance to align land use,

---

[iii] AWS is certainly not the only part of this story but has been called out as a major player. Dan Swinhoe, "The Amazon Factor in Virginia," Data Center Dynamics, November 6, 2024, https://www.datacenterdynamics.com/en/analysis/the-amazon-factor-in-virginia/. Amazon also touts its $51.9 billion investment in Virginia between 2011 and 2021 (capital + operations) in its data center infrastructure in Fairfax, Loudoun, and Prince William counties. Roger Wehner, "Learn About AWS's Long-Term Commitment to Virginia," Amazon, June 7, 2023, https://www.aboutamazon.com/news/aws/aws-commitment-to-virginia.

[iv] Under the decision, new data centers can access up to 50 percent capacity in the first year, 65 percent in the second, 80 percent in the third, and 90 percent in the fourth before getting full access to the grid.

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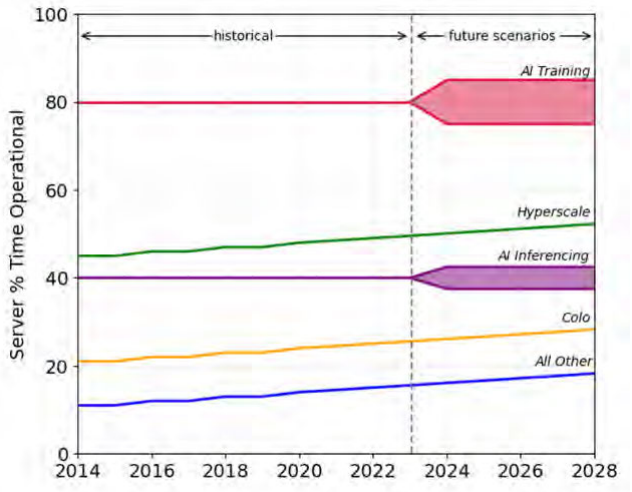
grid upgrades, generation, flexible loads, and permitting frameworks, ensuring that benefits can be captured without bottlenecks or backlash once clusters grow.

Data Center Feature 3: Consumption profile

Data center electricity usage is not steady or 24/7. Up close, it can be quite choppy and challenging. Batteries could act as a buffer—a keystone solution to managing power quality.

Figure 4 Server utilization by data center type. 2024 United States Data Center Energy Usage Report (LBNL).



Data centers exhibit considerable variability, especially going between operational and idle states. In Lawrence Berkeley National Laboratory's (LBNL) 2024 United States Data Center Energy Usage Report, the authors explain that in 2014 colos reported 21 percent utilization rates, hyperscalers 45 percent – rising to an estimated 35 percent and 50 percent respectively in 2027. The same report models AI learning centers and AI inferencing at 80 percent and 40 percent utilization rates, respectively. These don't directly translate into electricity consumption load factors because some electricity is used for other purposes like cooling that don't follow a 1:1 relationship with computing load.

Even looking at the whole power consumption profile of a data center, it's important to differentiate between actual load factor (the percentage of possible 24/7 full power use that a data center in fact uses) and availability (the percentage of maximum power a data center expects to have if it wants it, i.e., the *option* to use power). Whether power comes from on-site generation or from the grid, it needs to be prepared to provide power when the data center wants it, and back off when the data center doesn't.

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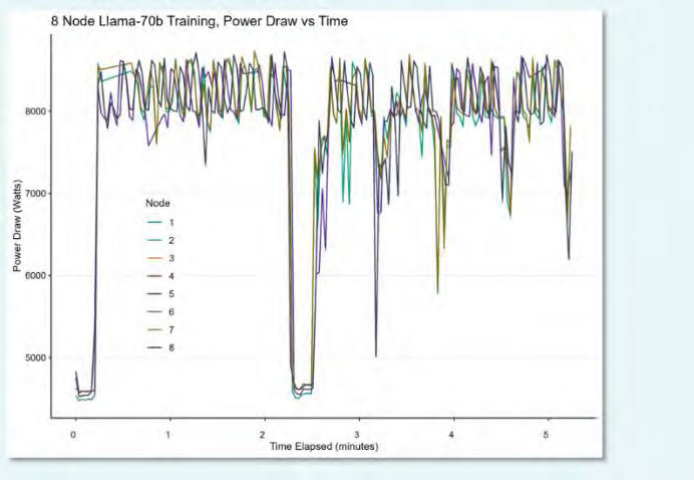
Figure 5 8 Node trace of power consumption in an AI learning cluster. 2024 United States Data Center Energy Usage Report (LBNL).



Big swings in data center demand will clearly be a challenge, even for the most flexible on-site generation. Given the scale at which many data centers operate, these swings can still create problems for large regional grids[v]. The CEO of Hitachi Energy reportedly commented "there can be swings of 200, 300 MW within a ten-minute period as data centers move from learn vs stop learn mode, and that these types of swings would not be acceptable from other grid customers."

At smaller time scales, large numbers of similar chips in one place switch on and off and can create an aggregate resonance effect[vi]. Existing electrical standards are inadequate for screening out these behaviors, and utilities may not have sufficient sensors to properly trace back issues to a particular data center. In aggregate, the evidence points to data centers deteriorating power quality metrics in their environs.[17]

More research needs to be done that focuses on new large digital loads, including variable generation resources with inverters that center around things like low-voltage ride through or fault clearing. For more information, context, and solutions on some of the challenges with interconnecting these large loads, see GridLab's recent Practical Guidance and Considerations for Large Load Interconnections.

Data centers are not a "perfect baseload" fit to directly couple with large mechanical generators or even the grid, and they will need significant electrical equipment to buffer this connection and prevent extra wear and tear on co-located generation or nearby grid users. Even if some data centers can learn to be flexible, incorporating battery energy storage, especially as the hardware cost decreases, will likely become a key element in managing data center impacts on the grid. When good wind and solar resources are available nearby, batteries can play a dual role in managing both load and generation variability at multiple time scales. Consider the Lancium Clean Campus in under construction in Abilene, Texas: "In addition to the 1.2 GW grid interconnection,

[v] See the GridLab report *Practical Guidance and Considerations for Large Load Interconnections*, with special attention to July 2024 Northern Virginia Data Center Event called out in Figure 1.2.
[vi] Some of these resonance issues can potentially be solved by on-chip energy management and storage. Rouslan Dimitrov et al., "How New GB300 NVL72 Features Provide Steady Power for AI," Nvidia, July 28, 2025, https://developer.nvidia.com/blog/how-new-gb300-nvl72-features-provide-steady-power-for-ai/?utm.

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Lancium's power plan for the site includes large-scale behind-the-meter battery storage and solar resources, which serve to ensure grid reliability, and economic and carbon optimization."[18]

Data Center Feature 4: Flexibility, or the lack thereof

Flexibility could be key to quickly connecting new data centers, especially those involved with AI learning. Managed demand is possible, but on-site batteries may be a better solution where split incentives or onsite needs make demand control too rigid or complex.

Data centers can be flexible, but different functions involve different levels of flexibility. This is probably hardest to achieve for co-location data centers because the third-party owner which interfaces with the grid and with utilities is not the one deciding what servers inside its facility are doing. Additionally, data centers are tasked with fluctuating sets of applications, creating uncertainty about how reliable or persistent demand management can be as a means of providing flexibility.

Data centers fully owned by large hyperscalers provide a higher degree of control over the whole facility. But the diversity of services being provided, often with low latency (response times) needs, may create constraints on what the hyperscaler can do. Hyperscale data centers provide both regular services—like AWS' cloud computing—and AI workloads such as inference, which involves answering client queries using pre-processed AI models.

For AI learning data centers, which create these large learning models, the goal is to cram as many chips as possible into the same square mile with the fastest internal connectivity so that the collection can operate as one big parallel machine[19]. Much of the possible flexibility here comes from adjusting the timing of computing batches, yet matching these adjustments to power supply flexibility needs is not a given, especially when considering that data center operators will want to prioritize computation over flexibility. This is a consequence of the relatively larger size of the capital investment in computing hardware versus energy generation and distribution for most applications.

Flexibility is a particularly important quality for data centers because they are such a large component of load growth, and just a little flexibility would reduce the need for new peaking resources and speed up interconnection[20]. A 2025 analysis[21] by the Nicholas Institute for Energy, Environment & Sustainability at Duke University finds that just 0.5 percent to 1 percent flexibility opens significant space on the grid: 98 GW of new load could be integrated at an average annual load curtailment rate of 0.5 percent, and 126 GW at a rate of one percent. This level of flexibility is similar to what is provided by demand-response programs that exist today for other loads, but as far as speeding up interconnection, it may be the AI-driven hyperscalers and learning centers, acting more directly under their owners' control and schedules, that can achieve more.

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AI loads are fundamentally more flexible than generic data center loads because they can be processed in batches, easily scheduled, and often internally orchestrated. For example, in a presentation[22] to the Texas grid operator Electric Reliability Council of Texas (ERCOT), the company Emerald AI demonstrated how it could implement flexibility at a data center. The company argued there is enormous potential to control AI data center load, and that "major hyperscalers are amenable to curtailing up to 25 percent for up to 200 hours in return for priority interconnection of 1 GW."

No one knows if any particular data center's operations will remain stable enough to guarantee a given level of flexibility or willingness to curtail over the lifetime of matching local grid upgrades. In some cases, the data center load can be flexible (willing to forgo some batches of work) but not exactly in the way that best serves the local grid. Some amount of local battery energy storage (providing multiple value streams like integrating local on-site variable energy, backup, and power quality services) could also help data centers be more flexible at their grid interface, especially those with less direct control over internal processes.

Data Center Feature 5: Backup needed for disturbances and outages

Most data centers require backup. Demand flexibility and short-duration batteries can either eliminate or lighten the load for traditional backup solutions.

Many data center customers aspire to high availability—as much as 99.999 percent uptime—hence the need for backup power to take over in case of any grid failure. The Uptime Institute, a widely followed source for industry tier certification in data center design, build, and operations,[23] defines four reliability tiers (I through IV) with increasing expectations for performance under challenging conditions, with an eye towards worst-case scenario planning. Many data centers serving enterprise needs require at least a Tier III level of reliability, either because of a direct need, like maintaining accessibility to data under adverse conditions, or as a proxy for operational trustworthiness. For mission-critical operations—major banks, stock exchanges, the military, or hyperscalers serving global customers—a Tier IV level of availability may be required.

Because Tier III and Tier IV facilities require 72 and 96 hours of on-site power capacity, respectively, simple economics dictate that backup is usually in the form of diesel generators with fuel storage on-site. Batteries can also be used to help ride-through disturbances in power supply,[vii] providing faster response times and reducing fuel and maintenance expenses on diesel. However, with today's technology, battery energy storage systems (BESS) that can cover critical needs for three to four days are not

[vii] In current facilities, this ride-through comes via the uninterrupted power system (UPS) usually provided by old-school lead-acid batteries, but modern lithium-ion battery energy systems can provide these services along-side the bulk of backup power needs.

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economically feasible, especially without some form of on-site generation to sustain their state of charge.[viii]

However, diesel does not scale well: As data centers get much larger, massive tank farms for the generators' on-site fuel require complex fire protection, spill containment, and environmental risk mitigation. Furthermore, many air districts (e.g., Virginia, California, or Oregon) place strict caps on generator run time and cumulative emissions in a site or region. Placing more than a hundred diesel generators on one site creates a cumulative permitting challenge and may well face serious local resistance along with the prospect of delays or outright rejection from regulators. Somewhat cleaner gas generators (turbines[ix] or reciprocating engines) are usually connected to a pipeline and require large propane or liquefied natural gas storage facilities to satisfy on-site capacity requirements.

Some large hyperscalers are opting to target better up-time based on statistical estimates rather than explicit proxies for reliability. For example, Microsoft has publicly committed to reducing the use of diesel generators by 2030. To that end, it contracted with Saft, a subsidiary of TotalEnergies, to install four battery energy storage systems, each in groups of four megawatt hours (MWh) and capable of 80 minutes of on-site power, to replace diesel backup.[24] In the U.S., Microsoft's newest Azure region in San Jose, California is also being built diesel-free, but is using natural gas turbines for backup (plus batteries for ride-through). In general, the U.S. grid is quite reliable, with the one-in-ten reliability standard[x] mostly achieved at the transmission service level.[xi] Most outages that do occur are less than one or two hours, so a battery can carry enough of the backup burden to get the facility to a high level of reliability while hardly, if ever, using on-site generation.

As longer-duration storage solutions like Form's 100-hour battery [25] or thermal batteries[26] connected to local renewables and steam turbines in local energy parks[27] emerge, data centers will be able to free themselves from fossil fuel backups while taking advantage of integrated design to combine multiple uses of batteries for flexibility, power quality, and backup.

[viii] To see how this is done in detail, see the NREL Vulcan platform demonstration in collaboration with Verrus. Deepthi Vaidhynathan et al., "Vulcan Test Platform: Demonstrating the Data Center as a Flexible Grid Asset" (National Renewable Energy Laboratory, June 2025), https://www.nrel.gov/docs/fy25osti/94844.pdf.

[ix] Although gas turbines face significant supply chain cost and delivery challenges currently. GridLab, *Gas Turbine Cost Report*, https://gridlab.org/gas-turbine-cost-report/.

[x] The one-in-ten reliability standard is a standard that applies for the bulk power system (i.e. transmission level) requiring transmission planners, system operators and reliability planners to aim for nor more than one "event" of involuntary load-shedding in ten years. If one "event" was 24 hours, that is already 99.97 percent up-time.

[xi] Actual recent figures for grid performance are quite good (see table 1.1). North American Electric Reliability Corporation, *2024 State of Reliability*, June 2024, https://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/NERC_SOR_2024_Technical_Assessment.pdf.

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Data Center Feature 6: Modularity—data centers are built in phases

Data centers expand in discrete phases, from racks to halls to entire campuses, with uncertain demand and rapidly rising power density. This modular growth pattern matches well with the modularity of renewables-plus-batteries deployment, which can be built in parallel to meet incremental load without the risks of lumpy firm power investments.

For utilities and data center developers, timing capital investments can be challenging. Matching these investments with energy supply for their increasingly electric power sub-components compounds the challenge. Building a new data center means committing to constructing a large building and grid capacity without knowing if consumers will come, how quickly they will deploy, or how their consumption will evolve over time. Tenants in a co-location situation, hyperscalers, and AI data centers may not immediately have all the chips available (or face some other bottleneck) so may want to deploy in phases: slowly building up electrical demand over time until reaching full capacity, if all the anticipated demand materializes. With a chip service life of around two to three years, the balance between increased efficiency and increased computing power may mean newer chips could either increase or decrease electricity demand in each physical asset footprint.[xii]

The digital world's infrastructure is itself modular—built from discrete, substitutable units. Data centers are not just abstract systems of bytes and tokens; they are also collections of tangible components: chips, servers, and, above all, racks. The rack is the main unit of reference: a cabinet holding multiple slender servers or "rack units." Racks are grouped into "pods" of 20–30, and an enterprise client might deploy a couple of pods at a time in either a dedicated or co-location facility. Some tenants lease only a handful of racks in a shared space, while hyperscalers may build entire halls of 200–400 racks, with multiple halls forming a single phase of expansion on a large campus[28].

The modular nature of data centers lets developers manage financial risk by building in phases, with the option to add new capacity quickly but in a planned way. Each phase, however, carries high stakes not only in capital cost but also in power demand. A 2024 Uptime Institute report[29], states finds that four- to six-kilowatt (kW) racks remain common, with a trend towards higher consumption today. Meanwhile, AI applications and high- performance computing are pushing the development of liquid-cooled racks with incredible increases in power density. Vertiv, an Ohio-based company that designs, manufactures, and services critical infrastructure for data centers, reported in its 2024 Investor Event Presentation[30] that extreme rack densities already reach 250 kW

[xii] This is certainly a question in flux. Google has reported that over a recent 12-month period, the energy footprint of the Median Gemini Apps text prompt dropped by 33x! At a given facility this can be achieved by increased throughput or reduced energy use, or both. Amin Vahdat and Jeff Dean, "Measuring the Environmental Impact of AI Inference," Google Cloud, August 21, 2025, https://cloud.google.com/blog/products/infrastructure/measuring-the-environmental-impact-of-ai-inference.

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per rack today and could exceed one MW within five years. That means a space the size of a bedroom closet could consume more power than a thousand average homes. As a result, a single phase of development for a data center might range from on the low end at 250 kW (two-dozen at 10–12 kW per rack) on the low end to 250 MW at the high end (a 1,000 liquid-cooled 250 kW racks) at the high end, with extra overhead for cooling.

The extreme end of data center development is exemplified by data center developer Vantage's recently announced plans [31] to build its $25 billion Frontier campus situated on 1,200 acres in Shackleford County, Texas, with an eventual total consumption of 1.4 GWs—close to average total consumptions of the states of either Rhode Island or Delaware. And this project is not alone: a September 2025 ERCOT staff report[32] to ERCOT's board details 130 GW of non-crypto data center load in the interconnection queue through 2030.[33] In the last few years, Texas has met new additional load with new, mostly clean generation. Of the 428 GWs of generation requests as of August 31, 2025, 204 GWs are for wind and solar and 180 GWs are for energy storage (together 90 percent of all requests).

Data center development may come in all levels of power consumption. However, because developers rarely build, install, and commission data centers in a single phase, projects of all sizes need a power supply that can grow and expand with them. When covering the incremental energy demand from a new data center, a large new single firm resource is an unwieldy indivisible capital investment. A modular approach with renewables plus batteries reduces risk and provides better economics: You're not committing to a single lump-sum investment in a 500 MW gas turbine; you can phase investments, optimize based on real usage, and spread spending—and risk—over time.

With computing loads that grow unevenly, modular investments let operators respond dynamically—deploy more solar, wind, or storage as AI racks come online. As a bonus, you can avoid supply chain bottlenecks because incremental installation bypasses the big lead times and equipment backlogs associated with large generator orders, enabling continuous expansion without project delays. Just as data centers grow in discrete steps, modular renewables and batteries let the grid grow in parallel.

These six features highlight why data center demand is complex, not just a flat, 24/7 block of constant load. We now turn to how supply options can, and cannot, match this demand.

THE BEST WAY TO MEET DATA CENTER DEMAND IS DIVERSE RESOURCE PORTFOLIOS

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When thinking about how to supply new demand from the rapidly growing data center industry, the key point to remember is **one-to-one matching with "firm" resources will not "solve" the load growth needs from data** centers.

In this section, we explain why single, stand-alone generation resource matching for any given industrial load has rarely been the historical course, and how and why that might change. We then describe the three resource buckets that new data center projects need to acquire to use the existing bulk power system. Finally, we discuss how the data center demand features described in the preceding section create further challenges and barriers in acquiring these resources.

Debunking the one-to-one matching myth

If you imagine data centers as large capital assets running power through expensive electronics 24/7, it seems natural to imagine a dedicated "captive" 24/7 power plant built to match this demand, with historical precedent for this one-to-one matching. For example, in the post-war era aluminum producer Alcoa built smelters near cheap grid sources of hydropower in New York and the Pacific Northwest along with captive coal plants in Indiana and Texas to feed the company's aluminum smelters and mills. Today, industrial facilities use on-site combined-heat-and-power (CHP) plants to consume both the electricity and waste heat from fuel-driven power plants to operate industrial facilities with high end-use efficiency, and thus lower energy costs. According to the U.S. Energy Information Administration's (EIA) latest Manufacturing Energy Consumption Survey from 2022, U.S. manufacturers produce around 17 percent of their electricity needs on-site (Table 11.1) and that on-site generation is 97 percent co-generation (Table 11.3).[xiii]

Single plants may not "play nice" with data centers

The demand characteristics of data centers described in the prior section raise immediate concerns regarding matching a captive plant with a data center. For example, while a data center may want 24/7 availability, its actual consumption will ramp up and down significantly with a profile that a large, single on-site generator might struggle to meet. Many fossil generators have a minimum dispatch level they cannot fall below, and "ramp rates" limits dictate how quickly they can adjust up and down. Furthermore, a modular, phased build-out does not lend itself to a single matching resource because in order to provide sufficient power for the full buildout,

[xiii] This survey defines co-generation as "the production of electrical energy and another form of useful energy, such as heat or steam, through the sequential use of energy. Cogeneration includes electricity generated from fossil fuels, such as natural gas, fuel oils, and coal; wood; and other biomass." In practice, the steam/heat is the main other energy output, so co-generation is often used as synonymous with CHP.

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the single resource would have to operate at lower, inefficient, dispatch levels during earlier phases of data center construction and operation.

Beyond a mismatch with the demand characteristics of data centers described in the prior section, there are additional reasons to question using a captive plant as a 1-1 match for a data center.

Captive power plants are not highly reliable alone

Table 4 from the North American Electric Reliability Corporation (NERC) 2024 State of Reliability Overview [34], shows the recent weighted forced outage rate (rate of unexpected failure) was 11.7 percent for coal, 7.7 percent for gas, 6.4 percent for hydro, and 2 percent for nuclear. Another relevant consideration is planned maintenance, like cleaning out coal boilers, maintaining and inspecting gas turbines, or refueling nuclear plants every 18-24 months.[xiv] This means a single supposedly "firm" plant will be unavailable for a double-digit percentage of time—not what data centers are looking for.

If an industry is set on self-supply, one strategy is to over-supply generation. Alcoa's Warrick, Indiana aluminum smelter and mill built three captive 144 MW coal plants alongside a 300 MW coal unit shared 50/50 with the local utility Vectren. With a total capacity of 732 MW but serving a local load of 550 MW,[35] the facility was clearly resilient to losing one unit and still running. But this effectively meant carrying 25 percent more capacity than necessary, without a guarantee of full reliability. Alcoa mitigated this extra cost by selling excess power to the grid and importing power from Unit 4 or the broader grid when necessary. This illustrates the general case that a grid connection remains both a sink for surplus and an important backup option; most on-site power is not fully independent and large loads will still want interconnection to the bulk power system. In fact, payment for grid backup (usually called "standby rates") is a common feature of CHP tariffs.[36].

What happens when the power plant is no longer needed?

An interesting postscript to the Alcoa Warrick plant story is that Alcoa announced it would shut down its aluminum smelter in 2016 (although it had partial restarts post 2018) because of poor market conditions [37] and transferred major rolling mill and finishing operations to Kaiser Aluminum in 2021.[38] It is now left with an unattractive coal generation asset, whose generation capacity now exceeds Alcoa's local demand and

[xiv] This is on average a 32-day process. Aaron Larson, "Planning Is Key to Successful Nuclear Refueling Outages," POWER Magazine, September 1, 2023, https://www.powermag.com/planning-is-key-to-successful-nuclear-refueling-outages/.

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will likely struggle to sell surplus capacity in the broader power market along with most coal assets,[39] which comes with significant environmental remediation liabilities.[xv]

This is always the risk with a captive power plant: One day the load will vanish because of changing economics. Investors will want to know if Plan B exists and that the captive plant is in and of itself an attractive asset with a bright future.

Co-location of prime power generation assets with data centers today

Grid bottlenecks create considerable talk about co-locating "prime power" generation[xvi] with new data centers. This might include leveraging existing nearby assets (for example, the Talen-Susquehanna deal which co-locates a data center next to a nuclear plant[40]), restarting mothballed generators, or building new on-site resources (such as gas plants). But these arrangements are not true one-to-one matches of generation with load, since they still depend heavily on a grid connection for full functionality, sometimes at the expense of other consumers.

For example, in the Talen-Susquehanna deal, the data center is physically adjacent to a pair of nuclear units. It is unlikely the units' output will ramp precisely in step with data center consumption. Therefore, matching local supply with demand creates net output—nuclear output minus on-site data center consumption—variability which must be managed by the grid operator. During the refueling of one nuclear unit, the other must pick up the data center load, thereby reducing exports to the grid. In effect, the grid acts as backup.

Hybrid arrangements using on-site power together with the grid can address bottlenecks. They combine physical and financial hedges. The Talen-Susquehanna deal, for instance, was eventually reshaped into a power purchase agreement after regulatory push-back.[41]. These hybrid deals share many of the properties—and many of the drawbacks—of other on-site generation deals discussed above.

If land is available, the best way to provide on-site prime power is not with a single firm resource but by using an energy park[42] with renewables and batteries, with backup from longer- duration storage and/or gas generators.[43] Then most of the generation is

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In 2024, Sierra Club and Environmental Integrity Project intervened in a case against Alcoa Warrick for "100+ permit violations" in 2022 and 2023, including releases of mercury, aluminum, chlorine, copper, fluoride, nickel, and zinc into the Ohio River. Environmental Integrity Project, "Groups Intervene in State Action to Stop Aluminum Smelting Plant's Illegal Dumping of Heavy Metals in Ohio River," February 21, 2024, https://environmentalintegrity.org/news/groups-intervene-in-state-action-to-stop-aluminum-smelting-plants-illegal-dumping-of-heavy-metals-in-ohio-river. There are also lingering questions regarding compliance for Warrick's "ash ponds" under the Environmental Protection Agency's Coal Combustion Residuals rules. Hoosier Environmental Council, "Today's EPA Action Means More Coal Ash Cleanup for Indiana" (press release), April 25, 2024, https://www.hecweb.org/wp-content/uploads/2024/04/PRESS-RELEASE-Todays-EPA-Action-Means-More-Coal-Ash-Cleanup-for-Indiana.pdf.

[xvi] Prime power is the continuous everyday power that powers the data center, as opposed to backup power There is also "bridge power" which is local generation which acts as prime power until a grid connection is put in place, and then becomes either backup or just a part of the supply portfolio.

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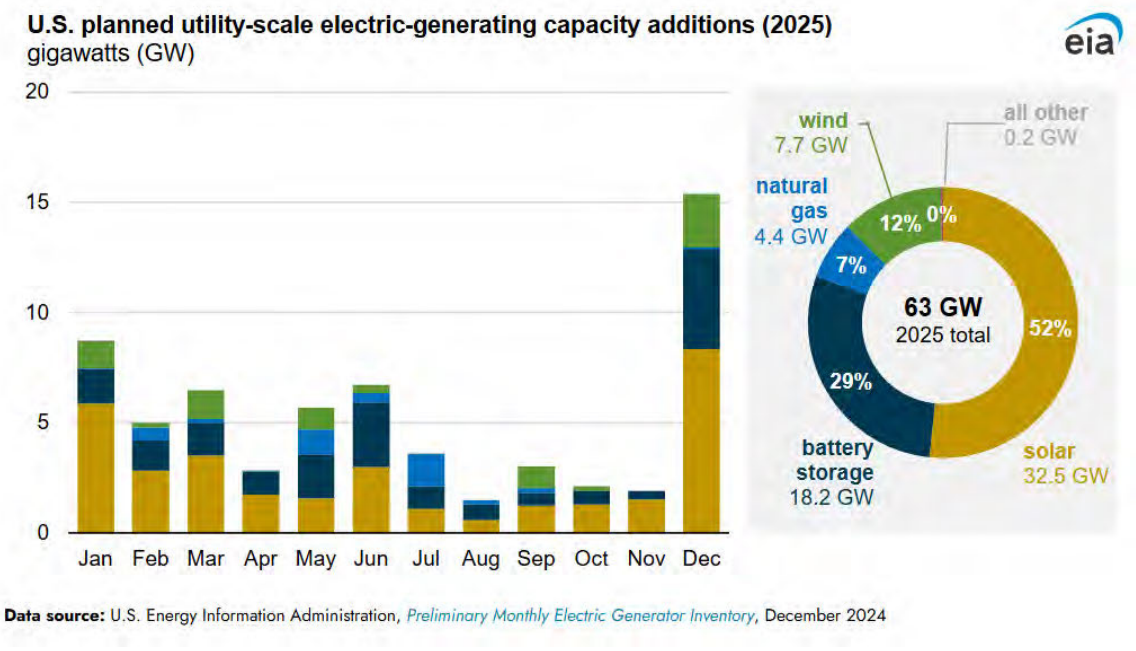
clean, faster, and cheaper to deploy than other generation and helpful for hyperscaler emissions commitments. In addition, the combined resource is more reliable, with fewer large points of failure than a handful of fossil units – a good Plan B if load never fully materializes or decreases. Included energy park resources would reflect a microcosm of trends in the wider U.S. market where the large majority of generation coming online[44] and waiting in interconnection queues are renewables and batteries.[45]

Figure 6 Solar, battery storage to lead new U.S. generating capacity additions in 2025. US EIA.



Data source: U.S. Energy Information Administration, *Preliminary Monthly Electric Generator Inventory*, December 2024

Providing new electricity supply for data centers from the bulk power grid

Given that most data centers will need to get some, if not all, of their power from the bulk power system, it is helpful to review how large commercial or industrial loads do this. The power grid is a system of systems including physical transmission and distribution poles and wires, the generation and loads they connect, operations and dispatch, power markets, and power purchase agreements.

As soon as a large new load decides to connect to the bulk power system, its needs can be disaggregated and met in many ways.

The grid resources a new data center project must collect to successfully draw from the bulk power system fall into three broad buckets: connection, grid services, and bulk electricity.

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New large data centers will require connection and network upgrades

How data centers connect to the grid depends on their size: scale matters. Smaller enterprise and co-location data centers (tens of MW or less) will often connect to a distribution system's high-end network (i.e., somewhere between 13.8 and 69 kilovolts) and may tie into an existing distribution substation with a new feeder. The utility typically owns and operates the primary substation equipment, while the data center customer owns the step-down transformer to its facility. The local utility conducts the impact studies and plans local upgrades to ensure compliance with NERC standards. Too many connections in the same area may trigger transmission upgrades and inclusion in transmission planning studies. In some geographies, like Virginia, this may involve an independent system operator (ISO) such as PJM [xvii] in planning and approving upgrades.

Larger data center campuses will have their own complex internal grid that connects directly to a bulk power system transmission substation. The data center must file a large load interconnection request with the local transmission owner or ISO. Tariffs and agreements will include matters like covering study costs, equipment ownership, and who pays for upgrades. The state may also require approvals for siting, environmental review, and cost recovery. The connection process can become long and painstaking once local capacity on the grid becomes tight. In Virginia's Dominion utility territory, data centers larger than 100 MW face up to a seven- year wait for power hookups.[46]

One important feature of new connection costs is that they are usually covered by the new load because cost causality is clear. Unfortunately, this may not hold true for more upstream transmission impacts where transmission upgrade costs are traditionally socialized more widely. A recent Natural Resources Defense Council (NRDC) report[47] tells the story in PJM: "Tight supply conditions led PJM to approve a $5 billion transmission expansion project to meet new data center demand in Virginia, where data centers already account for around a quarter of the state's electricity demand. The costs for this project were distributed by the Federal Energy Regulatory Commission (FERC), PJM, and utilities using varying cost allocation methods. Maryland residential customers were left with a bill of approximately $330 million, and Virginia residents had to foot $1.25 billion for transmission designed largely for a handful of data center customers in only a small region of the state."

Data centers create new stresses on a bulk power system planned around peak demand; they also consume other grid services

The main grid service data centers require regardless of size is peak capacity: the ability to serve up to their maximum interconnection rating during periods of system peak.

[xvii] Also referred to as a regional transmission operator, PJM covers 13 states in the mid-Atlantic and is one of the largest power markets in the world.

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Going back to PJM (often a source of current examples because it already serves so many data centers), the ISO's board chair communicated about future reliability concerns because: "PJM's 2025 long-term load forecast shows a peak load growth of 32 GW from 2024 to 2030. Of this, approximately 30 GW is projected to be from data centers."[48]

PJM's conundrum is how to keep the grid reliable as data center demand grows faster than new generation. Its "non-capacity-backed load" proposal would classify very large new loads (less than 50 MW) as customers outside the capacity market.[49]. The idea is to avoid shifting costs to others, but critics say that the 50 MW cutoff is arbitrary, curtailment rules could distort market signals, and contract and siting decisions may be disrupted.[50]. PJM is still debating whether the non-capacity-backed load should be voluntary or mandatory in shortage zones before filing at FERC for the 2028/29 delivery year.[51]

One challenge with resources like peak capacity is that once a project has been approved for interconnection, been built, and paid its share of costs, it becomes a load like any other. At that point, it is very difficult for the market to discriminate against it without creating efficiency concerns or legal risks. Data centers do more than strain peak supply; like all large loads with some variation, they also draw on ancillary services and other grid management resources.

If incremental demand is not met with increased supply, prices and emissions will rise

As the recent Nicholas Institute report[52] points out, some amount of flexibility from data centers could significantly reduce costs and delays associated with connection and peak demand constraints from new data centers. The report estimates peak load bottlenecks could be avoided for around 100 GW of so-called "curtailment-enabled headroom" on the U.S. grid. However, even if data centers avoid consumption during the most problematic hours, they still need power the rest of the time. Absent new supply on those same grids, the extra generation available off-peak will be from more expensive, and typically dirtier, marginal generation units.

Data centers' need to draw most of their power from existing units is thus a problem for other electricity customers because absent new matching supply, it will drive up their wholesale electricity costs. It is also problematic for the data centers themselves, which frequently are tied to corporations that have carbon reduction goals which are incompatible with increased emissions from existing fossil power plants. Conversely, new supply (especially cheap and clean supply) arriving quickly enough to offset data center consumption without requiring a large amount of new grid infrastructure creates potential for "beneficial electrification[53]" where more power over the same wires reduces other consumers' costs[54].

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Further consequences: Challenges and barriers specific to data centers

Connecting large new data center loads through the lens of three resource buckets faces three broad challenges required by all such loads. But these resource buckets also interact with the six more specific data center demand characteristics outlined in the preceding section.

Connection challenges specific to data centers

Because the source of many connection issues—or at least more expensive upgrades—come down to a limited set of hours and circumstances, flexibility is often cited as a master key for easing or speeding up connection. But flexibility is not always as simple to implement as first imagined, and other connection challenges specific to data centers are not necessarily circumvented with a touch of flexibility.

- **Agency:** Especially for co-location data centers, the operator is stuck between wanting to be more flexible to satisfy grid constraints and the imperative to be as generic as possible in contracts with tenants to accommodate as broad a class of customers as possible. Typical quality of service and service-level agreements also act as a barrier for to tapping flexibility.[55] Intervenors in public utility cases also question whether policies for ensuring new data centers cover all their incremental costs are effective[56].
- **Clustering:** Clustering leads to many data centers on the same part of the grid, necessitating more upstream transmission upgrades, as in the Virginia case mentioned cited by NRDC, mentioned above.
- **Consumption profile:** Big swings in power demand and power quality impacts on other consumers make data centers trickier for utilities and transmission providers to study and interconnect than simple 24/7 constant loads. Standard protection schemes and the collective behavior of 60 data centers recently caused a large reliability problem in Virginia in July 2024 when these data centers all dropped off the grid at once and caused a sudden surge in excess electricity that strained grid resources.[57]
- **Flexibility:** Some data centers are not flexible at all; others could be flexible but not in a manner consistent or predictable enough to satisfy the engineers running interconnection studies. These engineers are only likely to be satisfied after adding sophisticated energy management systems and large batteries, along with the promise of judicious backup power.
- **Backup:** As mentioned, backup power could be leveraged to facilitate connection or provide so-called "bridge power"[58] for data centers that cannot wait for interconnection. Unfortunately, backup power (used either for

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flexibility or bridge power) tends to be dirty, leading to siting and local community environmental concerns.[5960]

- **Modularity:** With a modular or phased build-out, a data center may ask up front for a large enough connection to accommodate all future phases, leading to stranded asset risk if all phases do not materialize.

Grid services challenges specific to data centers

Just as for solving connection issues, flexibility can help tamper the impact of new data centers on system-wide needs like peak capacity issues. A large overlap exists between local grid and larger grid issues with peak planning. However, as described in the prior section, flexibility is not always easy to implement or deploy in a manner which solves all challenges. Furthermore, the specific features of data centers tend to create additional challenges beyond help from simple load flexibility measures.

- **Agency:** Utilities often see new fossil resources like gas peakers as the easiest way to resolve new peak demand issues from data centers.[61] Because gas turbines are increasingly expensive, this may not be a good deal for other utility customers and may also entrench future emissions, working against many data center providers' and host states' clean power goals. Because eventual data center owner/operators tend to build where developers have prepared the ground, the fact that these developers may perceive emissions goals as secondary to "speed-to-power," and that utilities choose their own procurement path creates an agency mismatch.
- **Clustering:** The clustering of data centers tends to amplify their effects on the regional grid, with sharper surges in demand for grid services that cannot be accommodated fast enough through new resources builds.
- **Consumption profile:** While data centers don't run all the time, they plan their infrastructure for peak computing demand. This creates a knock-on effect for the bulk power system, which plans for peak power demand.
- **Flexibility:** Flexibility is not always a simple feature to implement or deploy.
- **Backup:** On-site backup power is a poor substitute for system resources because of expense as well as siting and local environmental concerns.
- **Modularity:** While the broader grid is in a good position to adjust to a phased build out of data center demand, this requires either coordination with the local utility or strong forward signals in the market to avoid disruptive demand shocks for grid services.

Bulk electricity challenges specific to data centers

Certain subcategories here (consumption profile, flexibility, modularity) concern time domains that do not apply when considering total annual consumption.

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- **Agency:** As with grid connection and services, intermediate entities between electricity provisioners and data center owner/operators with emissions goals may not consider the environmental impacts of reliance on using spare capacity from existing marginal resources.
- **Clustering:** Clustering means more annual electricity drawn from the same grid. This creates a greater need for new supply, amplifying the problems of price and emissions increases.
- **Consumption profile:** A variable but not necessarily predictable profile for large data center loads could create new challenges for grid operators, even at off-peak times.
- **Flexibility:** Data center demand flexibility could potentially alleviate emission concerns by targeting off-peak consumption more towards time periods with lower marginal emissions. This requires an extra layer of control on top of whatever that data center might have already committed to ease grid connection and mitigate impacts on grid operational resources.
- **Backup:** Supplying too much of the actual annual electricity use from backup power creates problematic environmental impacts.

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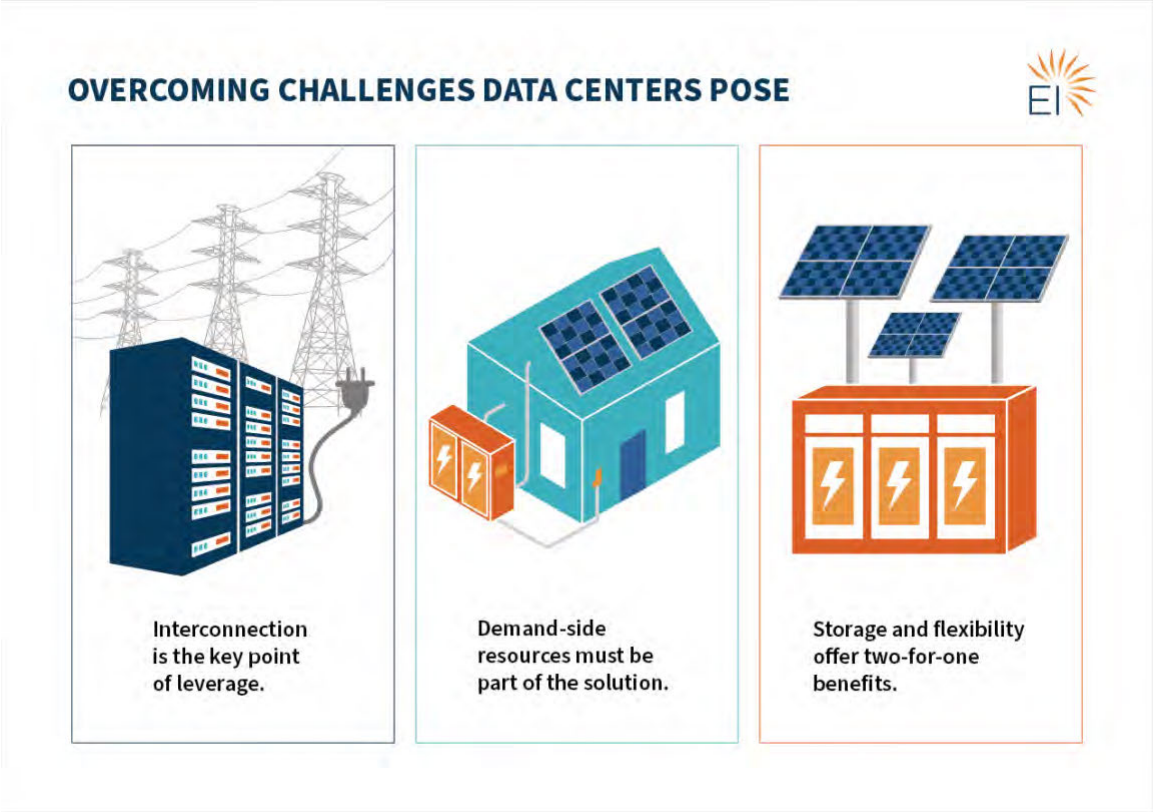
TAKEAWAYS FOR POLICYMAKERS AND OTHER STAKEHOLDERS

Figure 7 Three key takeaways



Many organizations (Clean Air Task Force/Brattle,[62] GridLab,[63] NRDC,[64] the Bipartisan Policy Center,[65] and the Regulatory Assistance Project[66]) have provided detailed and useful guides for coping with the challenges of meeting new data center loads.

This section distills the key lessons from the features and challenges discussed above.

Interconnection is the key point of leverage to influence when and how data centers join the grid

Accommodating large, dense new loads affects every grid participant, and the challenges show up at multiple scales. Geographically, they range from the substation where the data center connects to the entire interconnected system. In time, they span from sub-second transients to hours of local and bulk stress to the accumulation of annual demand.

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When issues are tied directly to a data center's load or its immediate connection, cost-causation principles are easier to apply. But at larger scales, like meeting new annual demand or rising peaks across a region, the problem is less about the nature of data centers than the pace and size of their growth. At that point, they can reasonably argue for being treated like any other customer buying power "at the pump," without special obligations.

This tension is what policymakers need to keep in mind. Interconnection is the moment of maximum leverage: not to extract unreasonable concessions, but to ensure new entrants cover the infrastructure costs they trigger, and to nudge them toward implementing solutions like flexible demand or local storage that relieve local bottlenecks and support the broader grid. Likewise, developers and customers should lean toward local fixes that speed access to the grid, improve power quality, and ease broader impacts—reducing the likelihood of being saddled with extraordinary requirements later.

Using other demand-side resources

In one of our earlier reports on meeting the load growth challenge,[67] we pointed out the importance of using demand-side resources to meet this challenge most efficiently. Often the discussion of demand-side solutions focuses on direct measures at a data center, especially in the wake of the efficiencies revealed in the DeepSeek announcement.[68] However, data centers can meet their resource needs with other demand-side resources elsewhere on the grid. Recently, Voltus, an aggregator of distributed energy resources (DERs), announced a deal with Cloverleaf Infrastructure—a data center developer—to meet new capacity needs from data centers with market-accredited capacity from DERs.[69] This kind of transaction compensates other existing customers and thus helps accommodate the rapid rise of data center loads fairly, speedily, and equitably. Since connecting to the grid can involve mixing and matching resources to relieve bottlenecks, once a data center has invested in the flexibility and extra equipment needed to resolve local connection issues, there is no reason why more upstream connection issues, grid services bottlenecks, and the need for a large amount of annual electricity delivery cannot be resolved with demand-side solutions from other grid users.

A recent Rewiring America report proposes many of the resources to meet data center load growth could come from sponsoring household upgrades.[70] The report finds that if hyperscalers paid 50 percent of the up-front cost of installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating, they could free up a total 30 GW of capacity on the grid. In addition, if hyperscalers paid 30 percent of the up-front cost of rooftop solar and storage in every single-family household in the U.S., they could add 109 GW of capacity on the grid. The cost of these upgrades would be comparable to the report's estimate of $315/kW-year to build and operate a new gas power plant.

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Storage and flexibility relieve data center challenges; they can also ease interconnection of new variable renewables

On-site prime generation solutions built around renewables and flexibility (modulating demand and using batteries) may provide cheaper, cleaner, and faster means for meeting new and existing data center demand. Because batteries are increasingly essential for buffering, backup, and power quality, they also provide a built-in solution for integrating variable renewables—offering a two-for-one advantage.

Furthermore, these renewable-plus-battery solutions can take advantage of existing surplus interconnection[71] to more quickly connect data centers to the grid in "power couples."[72]

By exploring the nuanced solutions, policymakers can avoid overcommitting to outdated firm resources and instead adopt strategies that embrace modularity, flexibility, and clean energy. Doing so will support both the digital economy's explosive growth and the clean energy transition.

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-46:
R Street Institute Commentary: DOE "Zombies" Are Eating
Competitive Power Markets

REAL SOLUTIONS

Low-Energy Fridays: DOE "Zombies" Are Eating Competitive Power Markets

BY MICHAEL GIBERSON

ISSUES: ELECTRICITY POLICY, ENERGY AND ENVIRONMENT

NOV 13, 2025

This past May, the U.S. Department of Energy (DOE) used emergency authority to stop two scheduled power plant retirements. As we explained in July, these emergency orders are not a good way to boost grid reliability. That's not the only problem, though—the DOE's emergency orders also threaten to undermine competition in regional power markets.

The case invoked Section 202(c) of the Federal Power Act, which limits most orders to just 90 days. The DOE used this law to block the coal-fired J.H. Campbell Power Plant in Michigan and two units at the gas- and oil-fired Eddystone Generation Station in Pennsylvania from retiring. When those 90-day orders expired in August, the DOE issued new orders to keep the plants online. When these orders expire later in November, the DOE is expected to order the plants to stay online for *another* 90 days. Both currently operate with a safety net: If they lose money, the law makes area consumers cover those losses. And with losses covered no matter what, the plants have little reason to run efficiently. The result isn't grid reliability—it's creeping zombification of the market.

Markets require profits *and* losses to steer investment where it's needed (and away from where it's not). When a unit can't cover its costs at market prices, it should retire. When older, inefficient plants exit, space opens on the grid and in the market for better resources to jump in. Prices may initially rise, but consumers benefit in the end as competition grinds down average costs. Serial "emergency" orders break the economic feedback loop and undermine competitive forces.

The DOE's decision to keep two fossil-fueled power plants running raised speculation that the administration would block any fossil-fueled plant from retirement. However, a New Hampshire coal unit retired in October without federal intervention. That's good, because a plant that doesn't contribute to reliability and energy supplies at a competitive price *should* retire. But the lack of clear policy heightens uncertainty.

The economic damage shows up in three places:

- **Crowding out.** When zombie power plants are ordered to stay in the market, customers are stuck with the bill from any losses. Market revenues that would support efficient resources get skimmed by units the market has already rejected. The effect is subtle but

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important: Energy market prices flatten, clean and firm resources see less upside in tight hours, and generation turnover slows.

- **Planning.** Reliability planning depends on credible schedules—retirements that can be believed, new power plants that can be counted, and rules that don't change unnecessarily. A plant yo-yoing between "retired," "ordered to run," and "maybe extended" in 90-day increments can't fit into long-run reliability plans.

- **Policy-driven uncertainty.** States and stakeholders are suing the DOE over the emergency orders because the law is being employed in a manner different from what Congress intended. The DOE has not articulated a clear policy for how they will use their authority in the future, which leaves plant owners and potential investors in the dark.

Emergency orders do have their place. If a hurricane hits, fuel freezes, or a wildfire takes out a major power line, use 202(c) for the days or weeks necessary and then stand down. Utilities regularly ask for these emergency orders when they need them. The difference with zombie plant orders is that neither the plant owners nor the grid operators responsible for reliability in their regions requested them.

Nothing in this discussion denies reality—demand for electricity is rising, interconnection queues are clogged, and grid operators face tough winters and hot summers. The way forward is in policies that make better use of the existing grid, drive economical additions to transmission infrastructure, and let market forces drive power plant entry *and* exit. Competitive power markets are not responsible for rising electricity rates; in fact, a recent study pointed to increased spending on transmission and distribution wires as key factors in driving up customer rates.

Should the DOE continue to undermine market competition, consumers may get hit with the double-whammy of rising energy costs and rising infrastructure spending. Zombification of the electricity industry is no way to support a reliable, efficient power system.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-47:
Palgrave Handbook



The Palgrave Handbook of International Energy Economics

Edited by Manfred Hafner · Giacomo Luciani

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rotating standby state through the advanced control system, and the gas turbine is quickly started with load, and the power is immediately transmitted to the power grid.

3.4 Location

Coal power generation location is more restrictive compared to other technologies because coal is a solid and its transport cost is high, while its combustion efficiency is lower than for other technologies. Usually coal plants are located near coal mines and the choice of different means of transport will affect the location of the plant area as well as the size and form of the required land plot, especially for a large power plant. The transportation mode should allow for large volume, low freight, high speed, and flexibility, which will make the location of coal plant all the more difficult.

On the contrary, oil is easy to transport with multiple transportation options including by pipeline and by ship; therefore, oil-fired plants are usually located in coastal areas. A gas-fired power plant is characterized by little land occupation and is very suitable for countries and areas with dense population and scarce land resources. Compared with coal-fired power plants, gas power generation equipment is more compact and does not occupy a large area. Besides, it consumes one-third of the water needed for a coal-fired power plant.

3.5 Expected Service Life

Thermal power plants are designed for an economic lifetime of 30 to 40 years, but some plants have been also used beyond their design life in certain areas. The critical components are the boiler and the turbine. The operation of thermal power generation is faced with both tangible and intangible aging processes. Tangible or physical aging refers to the equipment operating under high pressure and temperature, and bearing mechanical stress, resulting in physical and chemical changes, such as wear, creep, corrosion, and so on, gradually making the equipment unable to continue operating safely under the required design parameters. Invisible aging refers to technological progress. The advent of more efficient or less labor-intensive production equipment means that older equipment will operate under less and less economic conditions. The physical aging of some equipment (such as condenser copper pipes, heater pipes, boiler heating surface pipes, turbine blades, furnace walls, etc.) can be removed during overhaul. However, it is often the aging of these important equipment components that determines the technical and consequently economic lifetime of thermal power plants. Operating experience shows that the service life of equipment operating under 450 °C is between 40 and 50 years. For equipment operating at temperatures above 450 °C, the operating hours could even be reduced to 100,000 hours.

Both gas and steam turbines are devices that drive the rotor to rotate at high speed through high-pressure gas with high temperature and humidity.

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c)	)
Emergency Order: Tri-State	)
Generation and Transmission	)
Association, Platte River Power	)
Authority, Salt River Project,	)
PacifiCorp, and Xcel Energy	)

Exhibit to
Motion to Intervene and Request for Rehearing and Stay of
Public Interest Organizations

Exhibit 2-48:
IEA Report



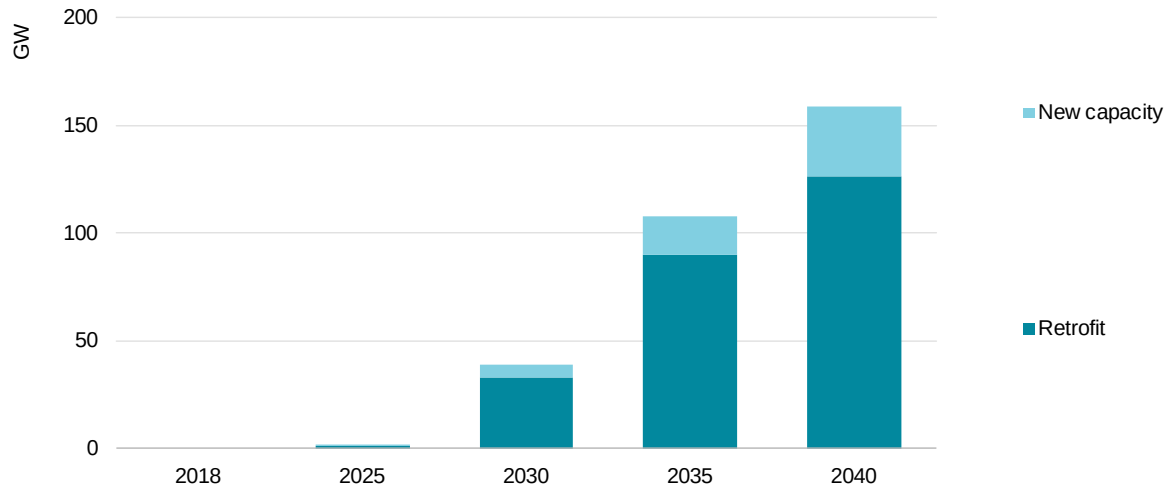
International Energy Agency

The role of CCUS in low-carbon power systems

Without carbon capture, meeting climate goals would ultimately mean almost eliminating the use of fossil fuels for power.

In the Sustainable Development Scenario, 120 GW of existing coal-fired capacity is retrofitted with carbon capture by 2040, accounting for some 80% of the coal plants equipped with these technologies. More than 110 GW of these retrofits are in China, representing a capital investment of around USD 160 billion. A further 10 GW are in the United States. Without carbon capture available at scale in power, coal-fired power generation, and eventually also gas-fired generation, would need to be virtually eliminated to meet long-term climate goals, with significant early retirements and potential stranding of assets.

Figure 4 **Coal-fired power plants equipped with carbon capture in the Sustainable Development Scenario**



Source: IEA (2019), World Energy Outlook 2019.

Over 750 GW of existing coal plants reduce operations to cut emissions in this Scenario, limiting electricity production but still providing system adequacy and flexibility. About one-quarter of the existing fleet would be retired before reaching the typical 50-year lifespan. Shutdowns and reduced operating hours are likely to lead to balance sheet write-downs for some owners of existing facilities. Coal plant retirements also imply greater investment in other low-carbon sources of electricity and associated network infrastructure.

Carbon capture retrofits also play an important role for the gas-fired power plant fleet, which currently has an average age of only around 19 years. In the SDS 155 GW of natural gas-fired power plants are equipped with carbon capture, utilisation and

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