July 2, 2026

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P.O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-22058

Dear Ms. Felice:

Please find attached for paperless, electronic filing the Official Exhibits and Exhibit List of the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar ("CEO"); the Michigan Energy Innovation Business Council ("MEIBC"); and the Institute for Energy Innovation ("IEI") (collectively "MEICEO"). Proof of service is also attached.

Please note this filing contains confidential information and has been redacted. The full, unredacted version has been filed under seal with the clerk.

Thank you,

Katie Schaschi Duckworth

Katie S. Duckworth (P86670)
Environmental Law & Policy Center
35 E Wacker Dr., Ste. 1600
Chicago, IL 60601
312-673-6500
kduckworth@elpc.org

cc: Service List, Case No. U-22058

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE ELECTRIC COMPANY for approval of special contracts and for other relief.	)))	Case No. U-22058

OFFICIAL EXHIBIT LIST

OF

THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR ENERGY INNOVATION, ECOLOGY CENTER, ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR (“MEICEO”)

Witness	Ex. #	Exhibit Description
William D. Kenworthy	MEICEO-1	Resume of William D. Kenworthy
	MEICEO-2	Testimony and Comments of William D. Kenworthy
Chelsea Hotaling	MEICEO-3	Resume of Chelsea Hotaling
	MEICEO-4	DTE response to CEOMEIBCIEIDE 1.8bi
	MEICEO-5	DTE response to AGDE 1.18
	MEICEO-6	DTE response to CEOMEIBCIEIDE 1.5a
	MEICEO-7	DTE response to CEOMEIBCIEIDE 1.16c
	MEICEO-8	DTE response to CEOMEIBCIEIDE 1.26
	MEICEO-9	DTE response to CEOMEIBCIEIDE 1.13
	MEICEO-10	DTE response to CEOMEIBCIEIDE 1.27a
	MEICEO-11	DTE responses to MNSDE 1.15a and to CEOMEIBCIEIDE 2.2ai

	MEICEO-12	DTE response to CEOMEIBCIEIDE 2.3a and 2.3b
	MEICEO-13	DTE response to CEOMEIBCIEIDE 1.20b
	MEICEO-14	DTE response to MNSDE 2.5b
	MEICEO-15	DTE response to CEOMEIBCIEIDE 1.14b
	MEICEO-16	DTE response to CEOMEIBCIEIDE 1.3c
	MEICEO-17	DTE response to MNSDE 1.2b
Lee Shaver	MEICEO-18	Resumé of Lee Shaver
	MEICEO-19	DTE response to AGDE-2.50b
	MEICEO-20	DTE response to CEOMEIBCIEIDE-1.12
	MEICEO-21	DTE responses to CEOMEIBCIEIDE-1.28a and 1.28ai
	MEICEO-22	DTE response to CEOMEIBCIEIDE-2.1d
	MEICEO-23	DTE responses to CEOMEIBCIEIDE-1.37b and 1.38a
	MEICEO-24	**Confidential** DTE response CEOMEIBCIEIDE-2.1c (S1)
	MEICEO-25	**Confidential** DTE response to MNSDE-1.10a
	MEICEO-26	DTE response to CEOMEIBCIEIDE-1.39a and 1.39b
	MEICEO-27	DTE response CEOMEIBCEIDE-3.2
	MEICEO-28	Elevate Energy Consulting & GridLab, Practical Guidance and Considerations for Large Load Interconnections (May 2025)
	MEICEO-29	North American Electric Reliability Corp., Characteristics and Risks of Emerging Large Loads White Paper (July 2025)
	MEICEO-30	North American Electric Reliability Corp., Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads White Paper (March 2026)
	MEICEO-31	**Confidential** DTE response to CEOMEIBCEIDE-4.1
Laura Sherman	MEICEO-32	Resumé of Dr. Laura S. Sherman

	MEICEO-33	DTE response to CEOMEIBCIEIDE-1.6b
	MEICEO-34	DTE response to CEOMEIBCIEIDE-1.33a
	MEICEO-35	DTE response to CEOMEIBCIEIDE-1.1a
	MEICEO-36	DTE response to CEOMEIBCIEIDE-1.8bi
	MEICEO-37	DTE response to CEOMEIBCIEIDE-1.9c
Hearing Exhibit	MEICEO-28	DTE response to CEOMEIBCIEIDE-5.1a-b, 5.2a-b, 5.3a-b, 5.3civ, 6.1a-b, 6.1bi-ii, 6.2a-b, 6.3a-b

William D. Kenworthy

1 South Dearborn Street, Suite 2000
Chicago, IL 60603
Phone: (704) 241-4394
Email: will@votesolar.org

Summary:

Energy industry leader and advocate with extensive expertise in electric industry structure, energy economics, and policy. Proven track record in advancing renewable energy, optimizing energy systems, and leveraging data-driven approaches, including machine learning, for process and financial optimization. Deep experience in distributed generation economics, regulatory strategy, and policy development to drive a cleaner, more equitable energy future.

Experience

Vote Solar
Regulatory Director, Midwest | *July 2018 - Present*
Lead regulatory strategy and advocacy efforts to advance solar and distributed energy resources across the Midwest. Serve as an expert witness, delivering testimony on technical, economic, and financial aspects of regulatory filings, utility rate cases, and grid modernization plans. Conduct in-depth policy analysis to shape regulatory outcomes that drive equitable access to clean energy. Manage the development and execution of regulatory strategies, collaborating with policymakers, utilities, and stakeholders to accelerate the transition to a just and resilient energy system.

Microgrid Energy
Managing Director, Midwest | *October 2017-June 2018 and October 2014-April 2016*
Managed operations of Chicago office for solar energy project development and EPC (engineering, procurement, and construction) company. Coordinated business development, market development, state and local policy efforts. Leveraged industry experience, strategic industry insight and market knowledge to enter new markets.

Infer Energy / Root3 Technologies
President | *April 2016 – October 2017*
Primary responsibility for marketing & business development for startup technology firm focused on providing energy optimization services to large industrial energy users. Successfully expanded business to the point at which was folded into the customer equipment health and maintenance offering of a large on-site energy generation provider.

Tipping Point Renewable Energy
Executive Vice President, Marketing & Business Development | January 2010 – April 2016
Led sales, marketing and business development process for startup solar energy project development and installation company

Governmental Strategies Incorporated
Vice President / Partner | *October 1996 – December 2007*
Senior partner in governmental affairs consulting practice. Developed and implemented strategic plans and marketing campaigns to affect public policy on behalf of Fortune 100 electric utility companies.

Nuclear Energy Institute
Director, Federal Legislative Affairs | *May 1992 – October 1996*
Developed and implemented strategic plans affecting public policy related to the ownership and operation of the nation's nuclear power plants and over 200 companies involved in the industry.

Provided technical assistance to legislators and their staffs in the development of energy policy, including facilitating cross-functional communications between technical personnel and legislative staff.

House Energy & Commerce Committee, U. S. House of Representatives
Professional Staff Member
May 1987 - August 1990
Represented Chairman John D. Dingell (D-MI) and Members of the Committee in dealings with other Members of Congress, the Executive Branch, private interests, and public organizations on energy & environmental policy. Professional staff team during the negotiation and drafting of the Clean Air Act Amendments of 1990.

Education

Yale University, School of Management
MBA / MPPM, Regulation and Competitive Strategies | May 1992

Georgetown University
BSFS, International Politics | May 1987

Community and Volunteer Activities

Jackalope Theater Company
Board Member | 2018-Present

Erie Family Health Foundation
Board Member | 2018 - 2021

Jefferson Avenue Center
President, Board of Trustees & Member | May 2012 – 2021

Georgetown University
Alumni Interviewer | June 2014 – Present

Columbus Academy
Member of Board of Trustees and Parent's Association President | June 2013 - December 2013

City of Upper Arlington Cultural Arts Commission
Commissioner and Chairman June 2012 – December 2013

CareRing of Charlotte
Member, Board of Trustees April 2004 - May 2008

Boy Scouts of America,
Assistant Scoutmaster, Cubmaster, Den Leader | September 2002 – September 2014

Skills / Software

Energy Modeling: NREL System Advisor Model (SAM), EnCompass
Productivity: Microsoft Office Suite
Business Intelligence / Data Visualization: Tableau, Tableau Prep, Python, NumPy
Adobe Creative Suite

Testimony and Comments of William D. Kenworthy

Regulatory Director, Midwest
Vote Solar
June 2, 2026

Testimony

Direct Testimony of William D. Kenworthy on behalf of the Joint Non-Governmental Organizations, Environmental Defense Fund, Environmental Law & Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar, Illinois Commerce Commission, Docket No. 26-0047, Commonwealth Edison Company, Petition for Approval of a Multi-Year Integrated Grid Plan Under Section 16-105.17 of the Public Utilities Act, May 14, 2026.

Direct Testimony of William D. Kenworthy on behalf of the Joint Non-Governmental Organizations, Environmental Defense Fund, Environmental Law & Policy Center, Natural Resources Defense Council, Union of Concerned Scientists, and Vote Solar, Illinois Commerce Commission, Docket No. 26-0051, Ameren Illinois Company d/b/a Ameren Illinois, Petition for Approval of Multi-Year Integrated Grid Plan pursuant to 220 ILCS 5/16-105.17, May 7, 2026.

Surrebuttal Testimony of William D. Kenworthy on behalf of Cooperative Energy Futures, the Environmental Law & Policy Center, Minnesota Interfaith Power and Light, and Vote Solar, Minnesota Public Utilities Commission, MPUC Docket Nos. E-002/GR-24-320 and E-002/M-24-321, CAH Docket No. 28-2500-40515, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, November 25, 2025.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, Natural Resources Defense Council, and Vote Solar, Illinois Commerce Commission, Docket No. 25-0678, Filing proposing three new tariffs, Rider BYODLR (Bring Your Own Device Load Reduction Program), Rider VPP (Virtual Power Plant Program), and Rider CSS (Community Solar Plus Storage Program), November 4, 2025.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Docket No. U-21870, In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief, September 30, 2025.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Case No. U-21860, In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority, August 22, 2025.

Direct Testimony of William D. Kenworthy on behalf of Cooperative Energy Futures, the Environmental Law & Policy Center, Minnesota Interfaith Power and Light, and Vote Solar, Minnesota Public Utilities Commission, MPUC Docket Nos. E-002/GR-24-320 and E-002/M-24-321, CAH Docket No. 28-2500-40515, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in Minnesota, August 22, 2025.

Direct Testimony of William D. Kenworthy on behalf of the Iowa Environmental Council, the Environmental Law & Policy Center, and the Sierra Club, Iowa Utilities Commission, Docket No. RPU-2025-0001, In re: MidAmerican Energy Company, May 29, 2025.

Direct Testimony on Rehearing of William D. Kenworthy, Illinois Commerce Commission, *Revenue-neutral Tariff Changes Related to Rate Design*, Docket No. 24-0378, on behalf of the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, April 29, 2025.

Direct Testimony of William D. Kenworthy on behalf of Solar United Neighbors, Virginia State Corporation Commission, Case No. PUR-2024-00222, *In re: Virginia Electric and Power Company, Application for approval of its 2024 DSM Update pursuant to § 56-585.1 A 5 of the Code of Virginia*, March 24, 2025

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Case No. U-21375, *In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations, and/or approvals necessary for DTE Electric Company to comply with Section 61 of 2016 PA 342*, February 13, 2025.

Direct Testimony of William D. Kenworthy on behalf of Vote Solar, Public Service Commission of Wisconsin, Docket No. 5-UR-111, *Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates*, August 21, 2024.

Direct Testimony of William D. Kenworthy on behalf of Vote Solar, Public Service Commission of Wisconsin, Docket No. 6690-UR-128, Joint Application of Wisconsin Electric Power Company and Wisconsin Gas LLC for Authority to Adjust Electric, Natural Gas, and Steam Rates, August 19, 2024.

Rebuttal Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Case No. U-21534, *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*, August 16, 2024.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service

Commission, Case No. U-21585, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, September 27, 2024.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar, Michigan Public Service Commission, Case No. U-21534, *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*, July 26, 2024.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Environmental Defense Fund, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Commonwealth Edison Company, Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0486 Refiled Grid Plan (RGP), July 17, 2024.

Rebuttal Testimony of William D. Kenworthy on behalf of Environmental Defense Fund Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Ameren Illinois Company Order Requiring Ameren Illinois Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0487 Refiled Grid Plan (RGP), July 3, 2024

Direct Testimony of William D. Kenworthy on behalf of Environmental Defense Fund, Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Commonwealth Edison Company Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0486 Refiled Grid Plan (RGP), May 23, 2024.

Direct Testimony of William D. Kenworthy on behalf of Environmental Defense Fund Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Ameren Illinois Company Order Requiring Ameren Illinois Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0487 Refiled Grid Plan, May 13, 2024.

Rebuttal Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of Indiana Michigan Power Company or authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission, Case No. U-21389, February 2, 2024.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of Indiana Michigan Power Company or authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission, Case No. U-21389, January 18, 2024.

Surrebuttal Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Wisconsin Power & Light Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 6680-UR-124, September 25, 2023.

Surrebuttal Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Madison Gas and Electric Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 3270-UR-125, September 20, 2023.

Rebuttal Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Wisconsin Power & Light Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 6680-UR-124, September 19, 2023.

Direct Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Wisconsin Power & Light Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 6680-UR-124, September 5, 2023.

Direct Testimony of William D. Kenworthy on behalf Vote Solar and Sierra Club, *Application of Madison Gas and Electric Company for Authority to Adjust Electric and Natural Gas Rates*, Wisconsin Public Service Commission, Docket No. 3270-UR-125, August 28, 2023.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Commonwealth Edison Company Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0486, July 26, 2023.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Ameren Illinois Company Order Requiring Ameren Illinois Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0487, July 13, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, Union Of Concerned Scientists, and Vote Solar, *In the matter of the Application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority,* Michigan Public Service Commission, Case No. U-21297, June 13, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Commonwealth Edison Company*

Order Requiring Commonwealth Edison Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act, Illinois Commerce Commission, Case No. 22-0486, May 22, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, the Natural Resources Defense Council, the Union of Concerned Scientists, and Vote Solar, *Illinois Commerce Commission On Its Own Motion vs. Ameren Illinois Company Order Requiring Ameren Illinois Company to file an Initial Multi-Year Integrated Grid Plan and Initiating Proceeding to Determine Whether the Plan is Reasonable and Complies with the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0487, May 11, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter, on the Commission's own motion regarding the regulatory reviews, revisions, determination and/or approvals necessary for DTE ELECTRIC COMPANY to comply with Section 61 of 2016 PA 342*, Michigan Public Service Commission, Case No. U-21172, April 21, 2023.

Rebuttal Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar, *In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief*, Michigan Public Service Commission, Case No. U-21193, April 10, 2023.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar, *In the matter of the application of DTE Electric Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief*, Michigan Public Service Commission, Case No. U-21193, March 9, 2023.

Surrebuttal, Testimony of William D. Kenworthy on behalf of Vote Solar, *Verified Petition of Vote Solar of Distributed Energy Resource Systems in Wisconsin*, Wisconsin Public Service Commission, Docket No. 9300-DR-106, October 21, 2022

Direct Testimony of William D. Kenworthy on behalf of Vote Solar, *Verified Petition of Vote Solar of Distributed Energy Resource Systems in Wisconsin*, Wisconsin Public Service Commission, Docket No. 9300-DR-106, September 16, 2022.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.*, Michigan Public Service Commission, Case No. U-21224, August 24, 2022.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center and Vote Solar, *Petition of for Approval of Performance and Tracking Metrics pursuant to 220 ILCS 5/16-108.18(e): Ameren Illinois Company d/b/a Ameren Illinois*. Illinois Commerce Commission, Case No. 22-0063, June 6, 2022.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of DTE ELECTRIC COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*, Michigan Public Service Commission, Case No. U-20836, May 19, 2022.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center and Vote Solar, *Petition of for Approval of Performance and Tracking Metrics pursuant to 220 ILCS 5/16-108.18(e): Commonwealth Edison Company*. Illinois Commerce Commission, Case No. 22-0067, April 6, 2022.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center and Vote Solar, *Petition of for Approval of Performance and Tracking Metrics pursuant to 220 ILCS 5/16-108.18(e): Ameren Illinois Company d/b/a Ameren Illinois*. Illinois Commerce Commission, Case No. 22-0063, March 30, 2022.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter, of the application of CONSUMERS ENERGY COMPANY For approval of Voluntary Green Pricing programs pursuant to Section 61 of 2016 PA 342.*, Michigan Public Service Commission, Case No. U-21134, March 17, 2022.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.*, Michigan Public Service Commission, Case No. U-21090, October 28, 2021.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission, Case No. U-20963, June 22, 2021.

Rebuttal Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar *In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations and/or approvals necessary for DTE ELECTRIC COMPANY to comply with Section 61 of 2016 PA 342*, Michigan Public Service Commission, Case No. U-20713, and *In the matter of DTE ELECTRIC COMPANY'S application for the regulatory reviews, revisions, determinations, and/or approvals to fully comply with Public Act 295 of 2008*, Michigan Public Service Commission, Case No. U-20851, May 4, 2021.

Direct Testimony of William D. Kenworthy on behalf of the Ecology Center, the Environmental Law & Policy Center, and Vote Solar *In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determinations and/or approvals necessary for DTE ELECTRIC COMPANY to comply with Section 61 of 2016 PA 342*, Michigan Public Service Commission, Case No. U-20713, and *In the matter of DTE ELECTRIC COMPANY'S application for the regulatory reviews, revisions, determinations, and/or approvals to fully comply with Public Act 295 of 2008*, Michigan Public Service Commission, Case No. U-20851, December 23, 2020.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, Vote Solar, and the Natural Resources Defense Council, *Investigation under Section 10-101 of the Public Utilities Act to determine whether Rider Net Metering requires amendment to comport with Section 16-107.5 of the Public Utilities Ac*t. Illinois Commerce Commission, Case No. 20-0738, October 26, 2020

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, Vote Solar, and the Natural Resources Defense Council, *Investigation under Section 10-101 of the Public Utilities Act to determine whether Rider Net Metering requires amendment to comport with Section 16-107.5 of the Public Utilities Ac*t. Illinois Commerce Commission, Case No. 20-0738, October 23, 2020.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center, Vote Solar, and the Natural Resources Defense Council, *Investigation under Section 16-107.6(e) of the Public Utilities Act into an annual process and formula for the calculation of distributed generation rebates,* Illinois Commerce Commission Case No. 20-0389, October 2, 2020.

Direct Testimony of William D. Kenworthy on behalf of the Citizens Action Coalition of Indiana, the Environmental Law & Policy Center, Solar United Neighbors, and Vote Solar on the *Petition of Southern Indiana Gas and Electric Company D/B/A Vectren Energy Delivery of Indiana, Inc. for Approval of a Tariff Rate for the Procurement of Excess Distributed Generation Pursuant to Indiana Code § 8-1.40 Et. Seq.*, Indiana Utility Regulatory Commission, Case No. 45378, August 20, 2020.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the application of CONSUMERS ENERGY COMPANY for approval of Voluntary Green Pricing programs pursuant to Section 61 of 2016 PA 342*, Michigan Public Service Commission, Case No. U-20649, June 25, 2020.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Great Lakes Renewable Energy Association, the Solar Energy Industries Association, and Vote Solar. *In the matter of the application of CONSUMERS ENERGY COMPANY for authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission, Case No. U-20697, June 24, 2020.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the application of CONSUMERS ENERGY COMPANY for approval of Voluntary Green Pricing programs pursuant to Section 61 of 2016 PA 342*, Michigan Public Service Commission, Case No. U-20649, May 28, 2020.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center and Vote Solar, *In the matter of Proposed Revisions to Rider Parallel Operation of Retail Customer Generating Facilities Community Supply*, Illinois Commerce Commission, Docket No. 19-1121, April 23, 2020.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law & Policy Center and Vote Solar, *In the matter of Proposed Revisions to Rider Parallel Operation of Retail Customer Generating Facilities Community Supply*, Illinois Commerce Commission, Docket No. 19-1121, February 21, 2020.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its* *rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* Michigan Public Service Commission, Case No. U-20561, November 6, 2019.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of Indiana Michigan Power Company for authority to increase its rates for the sale of electric energy and for approval of depreciation rates and other related matters,* Michigan Public Service Commission, Case No. U-20359, October 17, 2019.

Rebuttal Testimony of William D. Kenworthy on Behalf of the Environmental Law and Policy Center and Vote Solar*, In the Matter of the Joint Application of Wisconsin Power Company, Wisconsin Gas LLC, and Wisconsin Public Service Corporation to Adjust Electric, Natural Gas and Steam Rates,* Wisconsin Public Service Commission, Docket No. 5-UR-109, October 4, 2019.

Rebuttal Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center and the Iowa Environmental Council*, In re: Interstate Power & Light Compan*y, Iowa Utilities Board, Docket No. RPU-2019-001, September 10, 2019.

Direct Testimony of William D. Kenworthy on Behalf of the Environmental Law and Policy Center and Vote Solar*, In the Matter of the Joint Application of Wisconsin Power Company, Wisconsin Gas LLC, and Wisconsin Public Service Corporation to Adjust Electric, Natural Gas and Steam Rates,* Wisconsin Public Service Commission, Docket No. 5-UR-109, August 23, 2019.

Rebuttal Testimony of Will Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of Application of DTE ELECTRIC COMPANY for approval of its integrated resource plan pursuant to MCL 460.6t and for other relief*, Michigan Public Service Commission, Case No. U-20471, August 21, 2019.

Direct Testimony of William D. Kenworthy on behalf of the Environmental Law and Policy Center and the Iowa Environmental Council, *In re: Interstate Power & Light Company*, Iowa Utilities Board, Docket No. RPU-2019-001, August 1, 2019.

Rebuttal Testimony of Will Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for authority to increase its rate schedules and rules governing the distribution and supply of electric energy, and for other relief,* Michigan Public Service Commission, Case No. U-20162, November 28, 2018.

Direct Testimony of Will Kenworthy on behalf of the Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, and Vote Solar, *In the matter of the Application of DTE Electric Company for authority to increase its rate schedules and rules governing the distribution and supply of electric energy, and for other relief,* Michigan Public Service Commission, Case No. U-20162, November 7, 2018.

Comments

Reply Comments of the Environmental Law & Policy Center, Cooperative Energy Futures, and Vote Solar, In the Matter of Xcel Energy's 2025 Integrated Distribution Plan, Minnesota Public Utilities Commission, MPUC Docket No. E-002/M-25-142, April 23, 2026.

Initial Comments on Xcel's Integrated Distribution Plan of Environmental Law & Policy Center, Cooperative Energy Futures, and Vote Solar, In the Matter of Xcel Energy's 2025 Integrated Distribution Plan, Minnesota Public Utilities Commission, MPUC Docket No. E-002/M-25-142, February 26, 2026.

Supplemental Comments of Cooperative Energy Futures, Environmental Law and Policy Center, Institute for Local Self-Reliance, Solar United Neighbors, and Vote Solar, In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program, Minnesota Public Utilities Commission, MPUC Docket No. E002/M-25-378, January 27, 2026.

Initial Comments of Cooperative Energy Futures, Environmental Law and Policy Center, Institute for Local Self-Reliance, Solar United Neighbors, and Vote Solar, In the Matter of Northern States Power Company, dba Xcel Energy, Petition for Approval of Capacity*Connect, a Distributed Capacity Procurement (DCP) program, Minnesota Public Utilities Commission, MPUC Docket No. E002/M-25-378, December 10, 2025.

Settlement Comments of the Distributed Solar Parties, *In the Matter of Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan*, Docket No. E002/RP-24-67 and *In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation*, Docket No. E002/CN-23-212 / OAH Docket No. 71-2500-39923, Minnesota Public Utilities Commission, December 4, 2024.

Comments of the Distributed Solar Parties, *In the Matter of Xcel Energy's 2024-2040 Upper Midwest Integrated Resource Plan*, Minnesota Public Utilities Commission, PUC Docket No. E002/RP-24-67 August 9, 2024

Reply Comments Of The Ecology Center, The Environmental Law & Policy Center, The Union Of Concerned Scientists, And Vote Solar, *In the matter, on the Commission's own motion, to open a docket to establish a workgroup to review and consider issues related to the creation of financial incentives and penalties involving outages and distribution performance,* Case No. U-21400, October 20, 2023.

Comments Of The Ecology Center, The Environmental Law & Policy Center, The Union Of Concerned Scientists, And Vote Solar, *In the matter, on the Commission's own motion, to open a docket to establish a workgroup to review and consider issues related to the creation of financial incentives and penalties involving outages and distribution performance,* Case No. U-21400, September 22, 2023.

Comments of the Environmental Law & Policy Center, and Vote Solar on Locational Reliability/Equity Metric, *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics and, Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Docket No. E002/CI-17-401, and *In the Matter of Xcel Energy's Annual Report on Safety, Reliability, and Service Quality and Petition for Approval of Electric Reliability Standards*, Docket No. E002/M-20-406, January 6, 2023.

Comments of The Ecology Center, Environmental Law & Policy Center, Union Of Concerned Scientists And Vote Solar, *In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters*, Michigan Public Service Commission, Docket No. U-20147, November 1, 2022.

Responses to Objections of the Environmental Law & Policy Center, the Natural Resources Defense Council, and Vote Solar to The Illinois Power Agency's 2022 Long-Term Renewable Resources Procurement Plan, *Petition for Approval of the IPA's 2022 Long-Term Renewable Resources Procurement Plan pursuant to Section 16-111.5(b)(5)(ii) of the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0231, May 11, 2022.

Reply Comments of Community Power, Environmental Law & Policy Center, and Vote Solar, *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project*, PUC Docket No. E002/M-21-694, April 12, 2022.

Verified Objections of the Joint Non-Governmental Organizations to The Illinois Power Agency's 2022 Long-Term Renewable Resources Procurement Plan, *Petition for Approval of the IPA's 2022 Long-Term Renewable Resources Procurement Plan pursuant to Section 16-111.5(b)(5)(ii) of the Public Utilities Act*, Illinois Commerce Commission, Case No. 22-0231, April 4, 2022.

Initial Comments of Community Power, Environmental Law & Policy Center, and Vote Solar, *In the Matter of Xcel Energy's 2021 Integrated Distribution System Plan and Request for Certification of Distributed Intelligence and the Resilient Minneapolis Project*, PUC Docket No. E002/M-21-694, February 25, 2022.

Comments of Vote Solar on the Draft MI Healthy Climate Plan: Modeling the Benefits of Electrification and Decarbonization in the Power Sector in Michigan, February 23, 2022.

Verified Reply Comments of the Joint Non-Governmental Organizations on Amendment of 83 Ill.Adm. Code Parts 466 and 467, Illinois Commerce Commission, Docket No 20-0700, April 29, 2021.

Joint Comments of Vote Solar, the Institute for Local Self Reliance, the Environmental Law & Policy Center, and Cooperative Energy Futures, *In the Matter of Xcel Energy's 2020-2034 Upper Midwest Resource Plan*, PUC Docket No. E002/RP-19-368, February 11, 2021.

Verified Initial Comments of the Joint Non-Governmental Organizations on Amendment of 83 Ill.Adm. Code Parts 466 and 467, Illinois Commerce Commission, Docket No 20-0700, February 4, 2021.

Comments of Vote Solar in the Matter of Updating Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Established Under Minn. Stat. § 216B.1611, Minnesota Public Service Commission Docket No: E-999/CI-16-521, September 19, 2018.

Comments of Vote Solar, the Environmental Law and Policy Center, Natural Resources Defense Council, and Plugged In Strategies on the Michigan Distributed Planning Framework: MPSC Report. *In the matter, on the Commission's own motion, to open a docket for certain regulated* *electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters.* Case No. U-20147, October 5, 2018.

Comments of Vote Solar, the Environmental Law and Policy Center, Natural Resources Defense Council, and Plugged In Strategies on the Indiana Michigan Power Company's draft *Michigan Five Year Distribution Plan for 2019-2023* per the Commission's November 21, 2018 Order in Case No. U-20147, December 21, 2018.

Comments of Vote Solar in the Matter of the Commission's Inquiry into Standby Service Tariffs, Minnesota Public Service Commission Docket No: E999/CI-15-115, February 19, 2019.

Comments of Vote Solar in the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations, , Minnesota Public Service Commission Docket No: E002/CI-17-401, May 6, 2019.

Reply Comments of Vote Solar in the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations, , Minnesota Public Service Commission Docket No: E002/CI-17-401, June 6, 2019.

Supplemental Comments of Vote Solar in the Matter of the Commission's Inquiry into Standby Service Tariffs, Minnesota Public Service Commission Docket No: E999/CI-15-115, September 23, 2019.

Chelsea Hotaling

Senior Consultant

Chelsea is a Senior Consultant at Energy Futures Group, where she applies her deep knowledge of grid planning models to a variety of questions involving resource planning, generator economics, and resource adequacy. She routinely uses the EnCompass, Strategic Energy Risk Valuation Model ("SERVM"), PLEXOS, and AURORA models and has provided expert witness testimony before commissions in Colorado, Georgia, Iowa, Kentucky, Michigan, Montana, South Carolina, West Virginia, and Wisconsin.

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EXPERIENCE

Senior Consultant
Energy Futures Group, Hinesburg, VT
2025 - Present

Consultant
Energy Futures Group, Hinesburg, VT
2021 - 2024

Senior Analyst
Energy Futures Group, Hinesburg, VT
2020 - 2021

Analyst
Energy Futures Group, Hinesburg, VT
2019 - 2020

Intern
Sommer Energy, Canton, NY
2018 - 2019

Research Assistant
Clarkson University, Potsdam, NY
2016 - 2019

EDUCATION

Clarkson University
M.S., Data Analytics
2020

Clarkson University
M.S., Environmental Policy and Governance
2019

Clarkson University
M.B.A., Concentration in Environmental Management
2012

Elmira College
B.S., Accounting and Economics
2011

SELECT PROJECTS

The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy

2020, 2023 - 2024

Evaluated Santee Cooper's 2024 Annual Integrated Resource Plan Update. (2023-2024) Evaluated Dominion Energy South Carolina's 2024 Annual Integrated Resource Plan Update. (2023-2024) Performed EnCompass and SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Santee Cooper 2023 IRP. (2023) Performed SERVM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Dominion Energy South Carolina 2023 IRP. (2023) Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)

Minnesota Center for Environmental Advocacy

2019 - Present

Evaluated Xcel Energy's 2024 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation (2024). Evaluated Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to 2024) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)

GridLab

2022 - 2023

Performed capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system.

Sierra Club

2022 - 2023, 2025

Evaluated Louisville Gas & Electric and Kentucky Utilities (LG&E/KU) large load forecast presented in support of LG&E/KU's Certificate of Public Convenience and Necessity filing. (2025) Performed capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants. (2022 to 2023)

(continued on next page)

Chelsea Hotaling
Senior Consultant

SELECT PROJECTS (continued)

Citizens Action Coalition of Indiana 2019 - Present
Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs. (2019, 2022, 2025) Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (2022, 2025) Comments regarding CenterPoint Energy Indiana South's integrated resource plans to meet future energy and capacity needs. (2020, 2023) Comments regarding AES Indiana's integrated resource plans to meet future energy and capacity needs (2020, 2023). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs. (2019, 2022, 2025)

Georgia Interfaith Power & Light and Southface Energy Institute 2024 - 2025
Reviewed Georgia Power's 2025 IRP and developed alternative recommendations related to the large load forecast, the SERVM modeled used to develop the target reserve margin, and Georgia Power's proposed pathway for meeting projected load growth.

Clean Wisconsin 2024 - 2025
Performed capacity expansion and production cost modeling within PLEXOS to evaluate alternative resource portfolios to the plan put forward by Wisconsin Electric Power Company.

Southern Environmental Law Center 2024
Reviewed Tennessee Valley Authority's draft 2025 Integrated Resource Plan and provided recommendations for improvement related to the modeling of supply side resources, the Planning Reserve Margin study, and the development of scenarios and sensitivities.

Georgia Interfaith Power & Light 2023 - 2024
Reviewed Georgia Power's 2023 IRP Update and developed alternative recommendations related to the large load forecast, new resource assumptions, and Georgia Power's proposed pathway for meeting projected load growth.

West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia 2023 - 2024
Reviewed the commitment and operation of the Amos, Mitchell, and Mountaineer generating units during the 2023-2024 review period. (2024) Reviewed the commitment and operation of the Harrison and Fort Martin generating units during the 2022-2023 review period.

Natural Resources Defense Council 2023
Reviewed and provided comments on Ameren Missouri's 2023 Integrated Resource Plan.

Kentucky Resources Council and Kentuckians for the Commonwealth 2023
Reviewed and provided comments on Big Rivers Electric 2023 Integrated Resource Plan.

Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Appalachian Citizens' Law Center, and Mountain Association 2023
Reviewed and provided comments on Kentucky Power's 2023 Integrated Resource Plan.

The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar 2022 - 2023
Performed capacity expansion and production cost modeling within EnCompass to put forward an alternate plan to DTE's preferred plan in its 2022 IRP.

Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association 2022
Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan.

Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association 2022
Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan.

Chelsea Hotaling
Senior Consultant

ENERGY FUTURES GROUP

SELECT PROJECTS (continued)

The Department of Attorney General and Sierra Club 2022
Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan.

The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar 2020 - 2021
Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan.

Colorado Office of the Utility Consumer Advocate 2021
Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan.

Earthjustice 2019 - 2020
Evaluation of PREPA's request for proposals for temporary emergency generation. (May 2020) Evaluation of the Puerto Rico Electric Power Authority's 2019 Integrated Resource Plan. (2019 to 2020)

The Council for the New Energy Economics 2020 - 2024
Reviewed and submitted comments on Evergy's IRP filing in Kansas and Missouri. (2020 – 2024) Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).

EfficiencyOne 2019 - 2020
Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process.

Washington Electric Cooperative 2019 - 2020
Conducted the analysis for the 2020 Integrated Resource Plan.

Coalition for Clean Affordable Energy 2019 - 2020
Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio.

Institute for Energy Economics and Financial Analysis (IEEFA) 2018 - 2020
Evaluation of National Grid's long-term natural gas capacity report. (March 2020) Evaluation of the Puerto Rico Energy Commission's proposed wheeling regulation. (March 2019) Co-author for the report Retail Choice Will Not Bring Down Puerto Rico's High Electricity Rates. (August 2018) Evaluation of the Puerto Rico Energy Commission's proposed microgrid rules. (February 2018)

SELECT PUBLICATIONS

Hotaling, Chelsea, Stephen Bird, and Martin D. Heintzelman. "Willingness to pay for microgrids to enhance community resilience." *Energy Policy*, 154 (July 2021): 112248. https://doi.org/10.1016/j.enpol.2021.112248

Atems, Bebonchu and Chelsea Hotaling. "The effect of renewable and nonrenewable electricity generation on economic growth." *Energy Policy*, 112 (January 2018): 111-118. https://doi.org/10.1016/j.enpol.2017.10.015

Bird, Stephen and Chelsea Hotaling. "Multi-stakeholder microgrids for resilience and sustainability." *Environmental Hazards*, 16(2) (December 2016): 116-132. https://doi.org/10.1080/17477891.2016.1263181

Bird, Stephen, Amir Enayati, Chelsea Hotaling, and Tom Ortmeyer. "Resilient Community Microgrids: Governance and Operational Challenges." In *Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine*, edited by Alex Q. Huang and Wencong Su, 65-95. Elsevier, 2018.

Chelsea Hotaling

Senior Consultant

EXPERT TESTIMONY

Before the Kentucky Public Service Commission, Case No. 2025-00045. Application of Kentucky Utilities Company and Louisville Gas & Electric Company for Certificates of Public Convenience and Necessity and Site Compatibility Certificates. On behalf of Sierra Club.

Before the Georgia Public Service Commission, Docket No. 56002 and 56003. Georgia Power Company's 2025 Integrated Resource Plan and Application for the Certification, Decertification, and Amended Demand-Side Management Plan. On behalf of Georgia Interfaith Power & Light and Southface Energy Institute.

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-317. Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek Combustion Turbine Project. On behalf of Clean Wisconsin.

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-316. Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the Paris Reciprocating Internal Combustion Engines Project. On behalf of Clean Wisconsin.

Before the Public Service Commission of Montana, Docket No. 2024.05.053. NorthWestern Energy's Application to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Service Schedules, Cost Allocation, and Rate Design. On behalf of Montana Environmental Information Center, Human Resource Council District XI, Natural Resources Defense Council, and NW Energy Coalition ("Joint Parties").

Before the Kentucky Public Service Commission, Case No. 2024-00152. Application of Duke Energy Kentucky, Inc. for a Certificate of Public Convenience and Necessity to convert its wet flue gas desulfurization system from a quicklime reagent process to a limestone reagent handling system at its East Bend generating station and for approval to amend its Environmental Compliance Plan for recovery by environmental surcharge mechanism. On behalf of Sierra Club.

Before the Public Service Commission of West Virginia, Case No. 24-0413-E-ENEC. Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the Georgia Public Service Commission, Docket No. 55378. Georgia Power Company's 2023 Integrated Resource Plan Update. On behalf of Georgia Interfaith Power & Light.

Before the Public Service Commission of West Virginia, Case No. 23-0735-E-ENEC. *Petition and Investigation to Determine Reasonable Rates and Charges on and after January 1, 2024*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the South Carolina Public Service Commission, Docket No. 2023-154-E. On behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Before the South Carolina Public Service Commission, Docket No. 2023-9-E. On behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21193. *In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, and for other relief*. On behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.

Before the Kentucky Public Service Commission, Case Number 2022-00387. *In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC*. On behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council.

Before the Kentucky Public Service Commission, Case Number 2022-00371. I*n the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC*. On behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

Before the Iowa Utilities Board, Docket No. RPU-2022-0001. *Application for a Determination of Ratemaking Principle*. On behalf of Environmental Intervenors.

Chelsea Hotaling
Senior Consultant

ENERGY FUTURES GROUP

EXPERT TESTIMONY (continued)

Before the Michigan Public Service Commission, Case No. U-21189. *In the Matter of the Application of Indiana Michigan Power Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, Avoided Costs and for Other Relief*. On behalf of Attorney General Dana Nessel and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21090. *In the Matter of the Application of Consumers Energy Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t and for Other Relief*. On behalf of the Environmental Law and Policy Center, the Ecology Center, Union of Concerned Scientists, and Vote Solar.

Before the Public Utilities Commission of Colorado, Proceeding No. 21A-0141E. *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan*. On behalf of the Colorado Office of the Utility Consumer Advocate.

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.8bi	
Respondent: N. Foley	
Page: 1 of 1	

Question: 8. Refer to the direct testimony of Neal Foley at page 31 lines 23–25… b. With regards to the timeline of June 1, 2028 to May 31, 2033, if the ZRCs that the Customer transfers to the Company are from resources that still have a useful life beyond May 31, 2033: i. What will happen to the ZRCs after 2033?

Answer: The Company is not involved in the Customer's procurement of the ZRCs that it will transfer to the Company. On an annual basis, the Customer will transfer ZRCs to the Company that are effective for the upcoming MISO planning year (i.e., June 1 to the following May 31).

Beyond May 31, 2033, the Customer is not obligated to transfer ZRCs to the Company and therefore the Company will not have access to such ZRCs.

Attachment: *None*

MPSC Case No:	U-22058
Requester:	AG
Question No.:	AGDE-1.18
Respondent:	N. Foley
Page:	1 of 1

Question: 18. Refer to lines 20-22 on page 23 of Mr. Foley's direct testimony about the 300 MW of ZRCs being provided by the Customer from June 1, 2028 to May 31, 2033. Please explain why the credits are only provided for 5 years and what happens to the credits after five years.

Answer: See response to CEOMEIBCIEIDE-1.8bi for a description of the ZRC Product and what happens after May 31, 2033.

The duration of the ZRC transfer was a negotiated term agreed to by the Customer and the Company.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.5a	
Respondent: N. Foley	
Page: 1 of 1	

Question: 5. Refer to the direct testimony of Neal Foley at page 25, lines 13–15, which states that, "Included within the 480 MW of energy storage is up to 425 MW of 4-hour lithium-ion energy storage, and up to 55 MW of long duration storage (i.e., at least 8-hour duration)." However, witness Burgdorf indicates that the "Customer Data Center Case" resource plan includes 450 MW of energy storage made up of 400 MW of 4-hour energy storage and 50 MW of 8-hour energy storage. a. Please explain the discrepancies between these storage amounts.

Answer: The amounts modeled in the "Customer Data Center Case" in the Encompass modeling and used for the reliability modeling performed by Witness Brooks were 400 MW of 4-hour energy storage and 50 MW of 8-hour energy storage.

The additional "up to" amounts (for a total of 30 MWs more) that the Company is allowed to deploy under the CCAA account for potential variability in the size of projects bid into the Request for Proposal (RFP). This effectively provides the Company with a range (i.e., 400 to 425 MW of 4-hour storage and 50-55MW of long-duration storage) to select a portfolio while still deploying at least the 450 MW that was modeled by the Company.

Attachment: *None.*

Co-respondent: S. Burgdorf

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.16c	
Respondent: K. Bilyeu	
Page: 1 of 1	

Question: 16. Refer to the direct testimony of Shawn Burgdorf at page 9, lines 19–23. c. Please explain how the Company determined the solar and wind split of the 1,600 MW of renewable resources.

Answer: The Company conservatively modeled the 1,600 MW of renewable resources using solar assumptions.

Attachment: *None.*

CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22058

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.26	
Respondent: J. Brooks	
Page: 1 of 1	

Question: 26. Refer to the direct testimony of Justin Brooks and the discussion of the modeling performed in SERVM. Please provide all SERVM files necessary to execute runs within the SERVM software, including the SERVM .bak file, the SERVM release, and the executable file.

Answer: Please find the file NDA U-22058 CEOMEIDCIEI-1.26-01 SERVM_Customer2_v10_DB.bak for the SERVM database SQL backup file. As SERVM is a proprietary licensed software of PowerGEM the requester must contact PowerGEM in writing with DTE Electric’s counsel included on the correspondence to obtain the SERVM executable.

Attachment: NDA *U-22058 CEOMEIBCIEIDE-1.26-01 SERVM_Customer2_v10_DB.bak*

Co-respondent: Legal

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.13	
Respondent: K. Bilyeu	
Page: 1 of 1	

Question: 13. Refer to the direct testimony of Shawn Burgdorf at page 8, lines 8–11. Please provide the resource type, resource capacity, and timing of the "renewables associated with Oracle."

Answer: While no renewable projects were designated exclusively for Oracle, the model incorporated additional renewable resources to ensure compliance with the renewable requirements tied to the Oracle load. The amounts are included in both the "base case" and "customer datacenter case" and have no impact on the incremental cost between the cases. See table below for the resource type, capacity and timing.

Year	Capacity (MW)	Resource Type
2030	662	Solar
2031	332	Solar
2032	809	Solar

Attachment: *None.*

Co-respondent: S. Burgdorf

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.27a	
Respondent: J. Brooks	
Page: 1 of 1	

Question: 27. Refer to the direct testimony of Justin Brooks and the discussion of the modeling performed in SERVM. a. Please explain what retirement assumptions were modeled in SERVM for Monroe units 1–4.

Answer: Monroe 1 and 2 were retired with a date of 12/2032. Monroe 3 and 4 were retired with a date of 12/2028.

Attachment: *None*

MPSC Case No: U-22058	
Requester: MNS	
Question No.: MNSDE-1.15a	
Respondent: S. Burgdorf	
Page: 1 of 1	

Question: 15. Please refer to the Direct Testimony of Shawn D. Burgdorf, p. 9 lines 13-15 and p. 17 Table 2. With regards to the Base Case capacity resource mix: a. Identify the size in MW and any other assumed characteristics of the "proxy resource called 'TBD Resource(s)'" identified in Table 2 as being "incorporated" into the Base Case after 2032.

Answer: See Q15 of my direct testimony, lines 17-19. For purposes of this case, Monroe 1 and 2 were used as the "TDB proxy resources" past 2032. As also noted in Q15, the determination of future generation resources needed to replace Monroe Units 1 and 2 will occur in the Company's next IRP.

Attachment: *None.*

MPSC Case No: U-22058
Requester: CEOMEIBCIEI
Question No.: CEOMEIBCIEIDE-2.2a
Respondent: J. Brooks
Page: 1 of 1

Question: 2. Please refer to the testimony of Witness Burgdorf, page 9, lines 13–15, which states, "Therefore, in each case, the modeling assumes Monroe Units 1 and 2 continue operating throughout the analysis period, serving as a placeholder in each case for future replacement resources." In response to CEOMEIBCIEIDE-1.27a, the Company reported that Monroe 1 and 2 retired with a date of 12/2032 in the SERVM modeling.

a. Please explain if any replacement resources were modeled in SERVM for Monroe 1 and 2 for the 2033 study year.

Answer: Yes. See response to MNSDE-1.15a.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-2.3a	
Respondent: J. Brooks	
Page: 1 of 1	

Question: 3. Please refer to the testimony of Witness Brooks, page 8, lines 10–12, and the response to CEOMEIBCIEIDE-1.27a on the MISO Local Resource Zones modeled in SERVM.

a. Please explain what source was used to model the forecasted peak demand for each MISO Local Resource Zone for the 2029 and 2033 study years.

Answer: The file 20230428 LRTP Workshop Item 03b All Futures Load Forecast Summary (MISO)628685.xlsx was accessed from the MISO Website and was the source of the peak forecast for each LRZ. It can be accessed here: https://cdn.misoenergy.org/20230428%20LRTP%20Workshop%20Item%2003b%20All%20Futures%20Load%20Forecast%20Summary%20(MISO)628685.xlsx

Attachment: *None.*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-2.3b	
Respondent: J. Brooks	
Page: 1 of 1	

Question: 3. Please refer to the testimony of Witness Brooks, page 8, lines 10–12, and the response to CEOMEIBCIEIDE-1.27a on the MISO Local Resource Zones modeled in SERVM.

b. Please explain what source was used to develop the assumptions around future resources for each of the MISO Local Resource Zones for the 2029 and 2033 study years.

Answer: The MISO 2024 Regional Resource Assessment (RRA) was used for future resource assumptions. Installed Capacity information was downloaded from the MISO Juicebox (https://juicebox.org/miso/) for the 2024 RRA, at the zonal level. For LRZ7, the Consumers Energy 2024 Renewable Energy Plan was used to inform future resource assumptions within the zone.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.20b	
Respondent: S. Burgdorf	
Page: 1 of 1	

Question: 20. Refer to the direct testimony of Shawn Burgdorf at page 12, Table 1. b. Please confirm if the 727 MW of "Proxy CCGT w/CCS" is being added because of the expiration of the ZRC contract and demand response.

Answer: Not confirmed. The proxy CCGT with CCS was added to meet the total system reliability requirement needs in 2033 in the context of analyzing resource adequacy requirements solely for purposes of performing the customer benefit analysis in this special contract matter. While the expiration of the ZRC contract and demand response are factored into the 2033 analysis, they do not define the 2033 system reliability requirements. Refer to questions 17 and 18 of my direct testimony.

Attachment: None.

Co-respondent: J. Brooks

MPSC Case No: U-22058
Requester: MNS
Question No.: MNSDE-2.5b
Respondent: S. Burgdorf
Page: 1 of 1

Question: 5. Please refer to the Direct Testimony of Shawn D. Burgdorf, p. 11 lines 3-7: b. Confirm that the proxy CCGT is modeled only to support the addition of the Customer’s load. If not confirmed, explain why DTE would otherwise build the proxy CCGT.

Answer: Not confirmed. Refer to CEOMEIBCIEIDE-1.22. The Company does not designate specific individual resources as being used exclusively to serve the Customer’s load or any individual customer’s load. Instead, in its Integrated Resource Plan (IRP) modeling, the Company will evaluate the incremental impact of the Customer’s load on system resource needs by comparing portfolios with and without that load and identifying the additional capacity or energy resources required to reliably serve total system demand.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.14b	
Respondent: S. Burgdorf	
Page: 1 of 1	

Question: 14. Refer to the direct testimony of Shawn Burgdorf at page 8, lines 17–20. b. Please provide the source used for the capacity accreditation values.

Answer: The Planning Year 2025-2026 indicative results reference the first table of the "Planning Year 2025-2026 Indicative Direct Loss of Load (DLOL) Results" report. See attachment U-22058 CEOMEIBCIEIDE-1.14b_PY 25-26 Indicative DLOL Results.pdf. The forecasted outyear class level percentages reference Appendix 5: DLOL by fuel Class from the "2024 Regional Resource Assessment" slide deck that was presented at the November 6, 2024 Resource Adequacy Subcommittee. See attachment U-22058 CEOMEIBCIEIDE-1.14b_20241106 RASC Item 10 2024 RRA Update.pdf.

Attachment:

U-22058 CEOMEIBCIEIDE-1.14b_PY 25-26 Indicative DLOL Results.pdf
U-22058 CEOMEIBCIEIDE-1.14b_20241106 RASC Item 10 2024 RRA Update.pdf

MISO

2024 Regional Resource Assessment

Resource Adequacy Subcommittee

November 6, 2024

Results from this presentation are interim and may change as the full process is implemented.

Purpose & Key Takeaways

Purpose: To review the interim results of the Regional Resource Assessment (RRA) and discuss remaining steps before releasing the results in the December workshop

Key Takeaways:

- MISO's RRA provides a collective view of how resource plans are evolving in the longer term, providing insights that can inform the work that members, states and MISO are doing to balance reliability, affordability and sustainability priorities
- Interim results frame the areas of capacity needs, resource composition, accreditation trends and ramp-up capability
- Final results and insights summary will be presented during the December 18 RRA Workshop, and the final report will be published in January 2025

Overview of RRA Process

The Regional Resource Assessment (RRA) starts from publicly available plans and policy objectives and informs the region's various priorities

- As the generation fleet evolves, more regional coordination is needed to develop a forward-looking, transparent view that ensures ongoing reliability
- Utilities are taking increasingly different approaches to meet member and state policy objectives and customer needs; information members need for resource planning may not be visible
- System complexities and needs will continue to grow as the grid evolves, requiring foresight and preparation
- MISO published the first iteration of the RRA in November 2021, with the goal of improving and expanding upon the effort year-over-year

The Regional Resource Assessment captures member plans and objectives to project resource adequacy and flexibility implications in the MISO footprint over a 20-year horizon

INPUTS

- 2024 RRA Survey of MISO member and state policy objectives*, plans, retirements, signed Generator Interconnection Agreements as of February 29, 2024
- Future 2A load
- Initial** seasonal PRMR based on DLOL, gathered from Market Redefinition: Accreditation Reform (Appendix A)
- Initial** seasonal resource accreditation based on 2023 Attributes work that is a function of class-installed capacity
- Assumed capital costs of new units from 2023 National Renewable Energy Lab Annual Technology Baseline (NREL ATB)
- Assumed gas prices from March 2024 Gas Pipeline Competition Model (GPCM)

PLEXOS MODEL

OUTPUT

A resource projection that satisfies member and state policy objectives for the next 20 years as well as accredited capacity needs, with three categories of units:

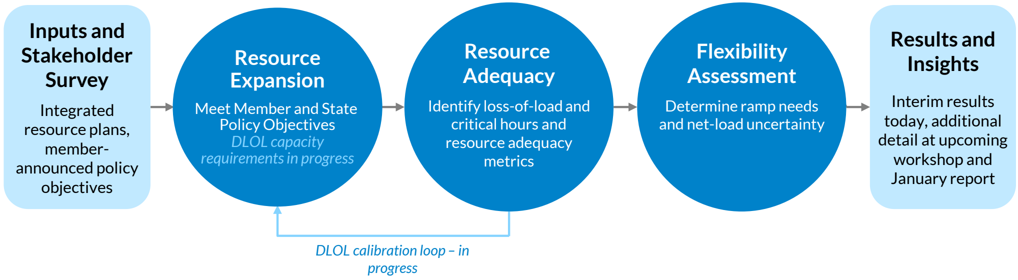
Existing: resource in-service from 2024 or earlier

Planned: future resource in-service after 2024, from survey, signed GIAs, or filed Integrated Resource Plans (IRPs)

Model-built: simulation-selected resource to meet planning reserve margin and member plans

*Member and state policy objectives include Renewable Portfolio Standards (RPS), Clean Energy Standards (CES), and Carbon Emission Limitation objectives, both legislated and non-legislated
**Final values of DLOL and PRMR are established through an iterative "DLOL calibration" process that involves resource expansion and resource adequacy modeling. The iterative process begins with the initial values described here. This effort is still in progress.

Today's discussion will focus on key insights from interim Regional Resource Assessment, Flexibility Assessment and Resource Adequacy Assessment results



2024 RRA Interim Results

DLOL: Direct Loss of Load
ICAP: Installed Capacity
PRMR: Planning Reserve Margin Requirement
LOLE: Loss of Load Expectation

UCAP-PRMR is substitute with DLOL-PRMR to acknowledge the underlying accreditation assumptions in the PRMR calculations

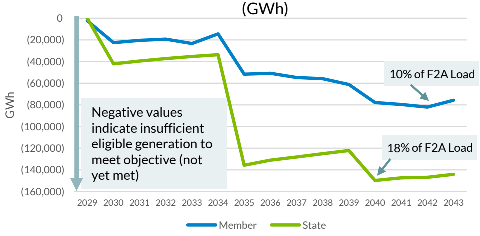
2024 RRA Interim Results Takeaways

- Meeting member and state policy objectives with Future 2A load growth will require more resources than identified in the RRA survey
- 343 GW of planned and model-built installed capacity may be needed in next 20 years
- Wind and solar may account for 62% of installed capacity and 85% of annual energy served by 2043
- As the risk of loss of load shifts, DLOL accredited capacity at the MISO level remains dominated by thermal resources throughout 2043
- Ramp-up capability increases in future years and peak net-load ramp follows trend of shifting from morning to evening, and becomes highest in a non-summer month

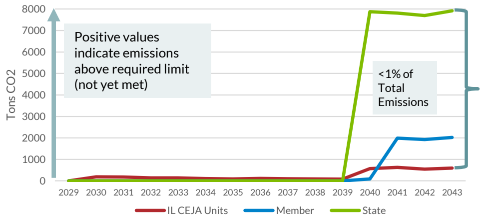
Meeting member and state policy objectives with Future 2A load growth will require more resources than identified in the RRA survey

Policy objectives include both generation-based objectives (RPS/CES) and carbon emission limitation-based objectives, legislated and non-legislated.

Renewable Portfolio Standards / Clean Energy Standards **not yet met** with Members Only Portfolio (GWh)



Carbon emission limitation **not yet met** with Members Only Portfolio (tons)

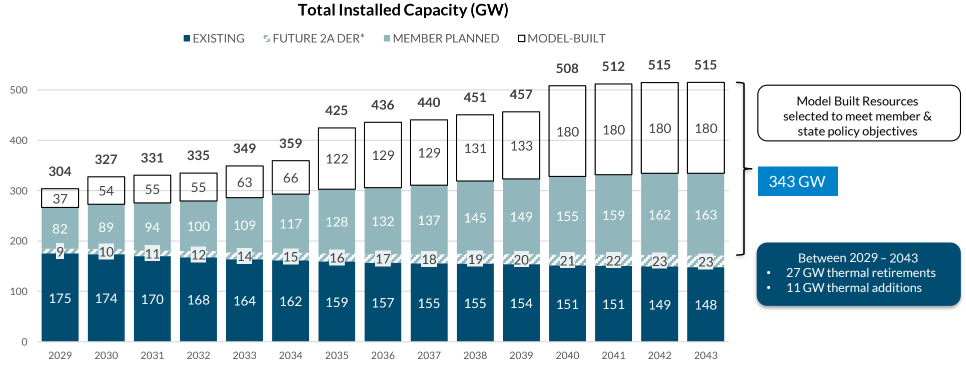


- Member and State RPS/CES policy objectives are unmet with Future 2A load growth assumptions from the beginning of the study period
- Policy objectives not yet met increases in key milestone years 2030,2035, and 2040, reflecting member and state policies defined in 5-year stepwise increments

- IL CEJA units show small violation in allowed emissions starting in 2030. Members and remaining states show violations starting in 2040.
- Emissions above limitations represent <1% of total emissions by 2043.

Member and state policy objectives were modeled individually at the entity level; "member" and "state" aggregates are for reporting only and do not reflect constraints as modeled. Given overlap, member deficit and state deficit are not additive. CEJA: Illinois Clean Energy Jobs Act

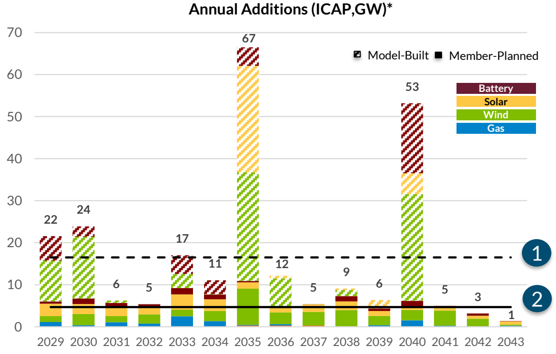
343 GW of additional member-planned and model-built installed capacity may be needed by 2043 to meet Member/State policy and resource adequacy objectives



Future 2A included 471 GW of installed capacity, including 369 GW of planned and model-built resources by 2042. Assumptions and capacity expansion tool differ between the two studies, but indicate directional alignment

*Future 2A DER: The 2024 RRA utilizes Future 2A load assumptions. Future 2A distributed energy resource (DER) assumptions, developed by AEG based on DER technical potential during Series 1, include Demand Response (DR), Energy Efficiency (EE), and Distributed Generation (DG). For the 2024 RRA, Energy Efficiency was netted from load; DR and DGPV are reflected as resource additions.

Achieving 343 GW* of additional installed capacity by 2043 would require an average installation of 17 GW per year over the next 20 years to achieve which is more than 3.5 times greater than the recent installation rate



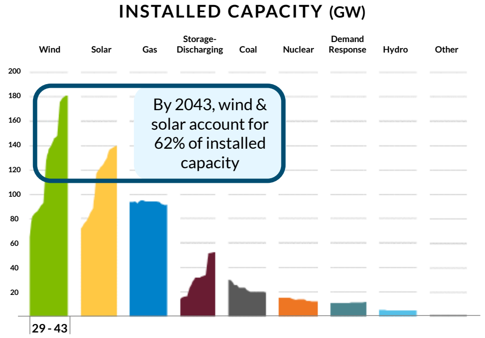
Key Takeaways

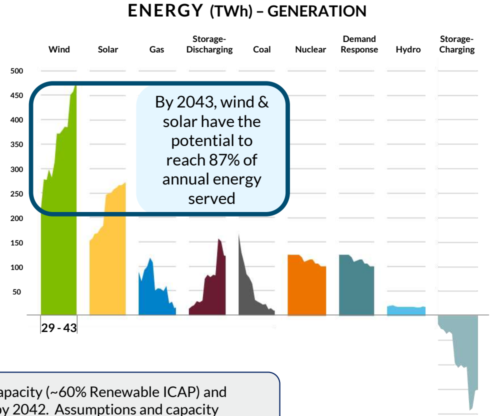
1. 343 GW of additional ICAP by 2043 would require an average of **17 GW/year (ICAP)** over the next 20 years to achieve.
2. The 3-year historical average rate of additions (planning years 2020-2022) is **4.7 GW/year (ICAP)**.**

Large annual additions in 2030, 2035 and 2040 are due to step increases in policy objectives at milestone years. The amount of annual capacity able to be built by the model was left unconstrained.

*343 GW additional installed capacity value reflects cumulative member-planned and model-build resources from 2024-2043; incremental annual additions on this slide reflect alternative 2029 – 2043-time horizon. **Three-year historical average (PY20-22) based on the 2024 OMS-MISO Survey Results, converted from 2.3 GW/yr UCAP to equivalent 4.7 GW/year ICAP. Link

Wind, solar and storage show meaningful installed capacity growth and will mirror those results in energy generation, other resources are flat to declining





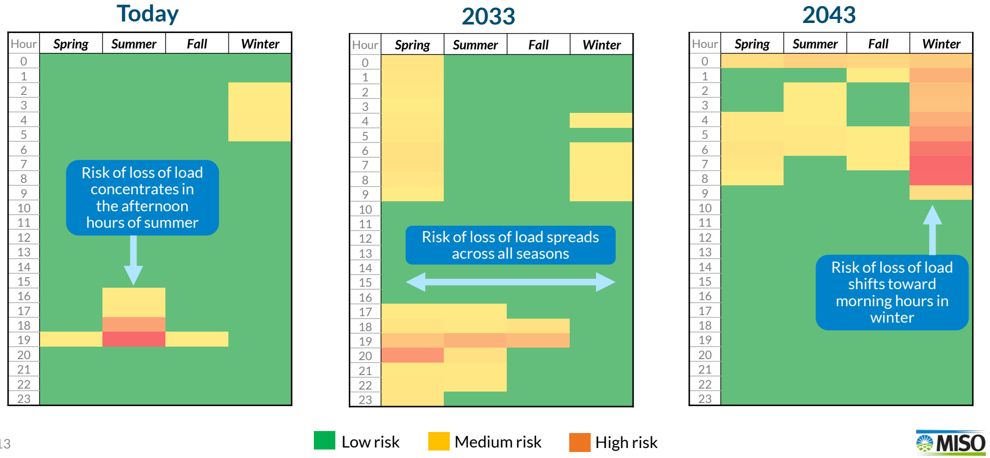
Future 2A included 471 GW of installed capacity (~60% Renewable ICAP) and resulted in 83% renewable penetration by 2042. Assumptions and capacity expansion tool differ between the two studies, but indicate directional alignment

Case No. U-22058
Exhibit MEICEO-15
Witness: Hotaling
Date: June 5, 2026

MPSC Case No.: U-22058
Requestor: CEOMEIBCIEIDE
Question No.:CEOMEIBCIEIDE-1.14b
Respondent:S. Burgdorf

Michigan Public Service Commission
DTE Electric Company
U-22058 CEOMEIBCIEIDE-1.14b_20241106 RASC Item 10 2024 RRA Update

As the resource fleet evolves, the risk of loss of load shifts toward hours outside of the historical summer peak-load conditions and concentrates in the early morning hours of the winter season



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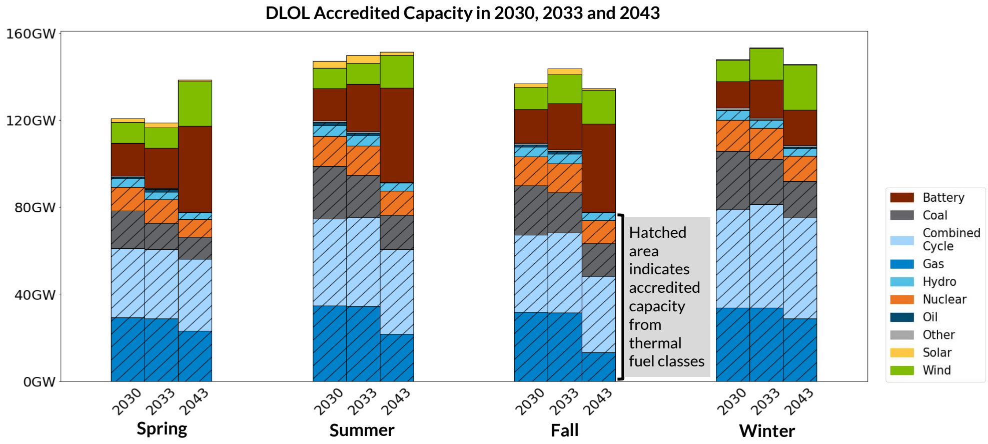
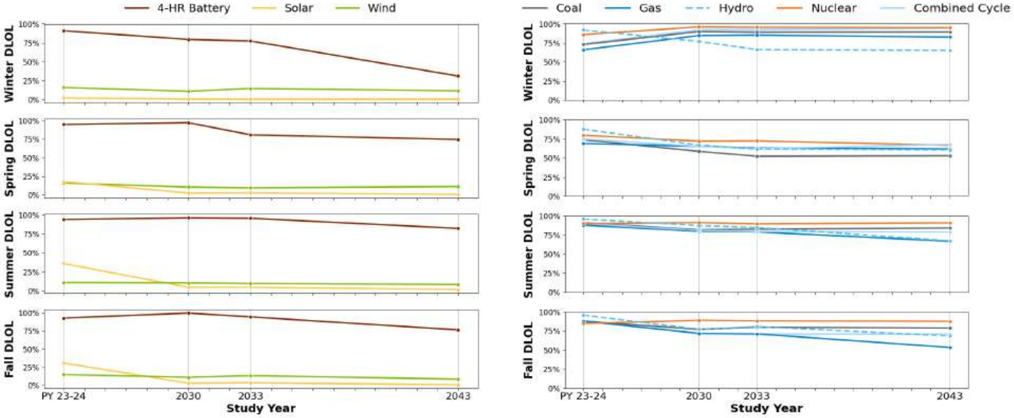
DLOL-accredited capacity continues to be dominated by thermal resources due to member-reported plans to retain these resources



DLOL accreditation of resource classes reflects availability during loss-of-load and low-margin hours and changes as the fleet evolves

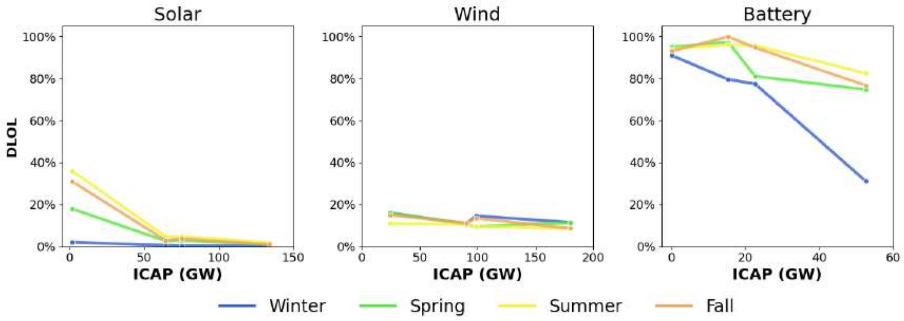
Change in resource class DLOL accredited value by Study Year



*Rest of the resource classes will be presented at the December's workshop. Storage dispatch assumption is included in Appendix 3.
PY 2023/24 DLOL: https://cdn.misoenergy.org/20240228%20RASC%20Item%2005a%20Accreditation%20Presentation%20RASC-2020-4%202019-2631885.pdf

Wind accreditation shows little variation as its capacity increases, while battery and solar accreditation decreases with an increase in its capacity due to longer duration of EUE events in winter

Change in DLOL by Installed Capacity (ICAP) of Fuel Class



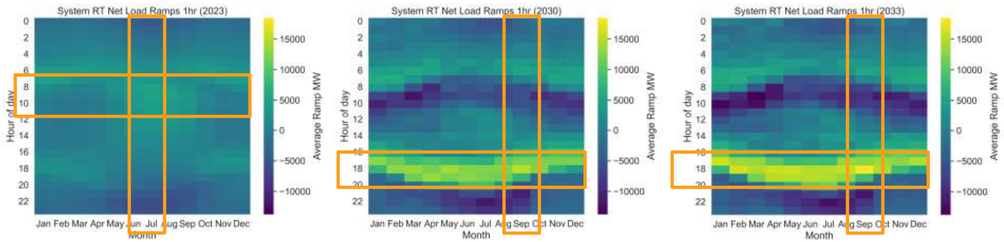
PY 2023/24 DLOL values (first set of points on each plot) was extracted from February RASC deck:
https://cdn.misoenergy.org/20240228%20RASC%20Item%2005a%20Accreditation%20Presentation%20RASC-2020-4%202019-2631885.pdf

MISO

The systemwide need for ramp-up capability increases in future years and the peak net-load ramp follows the trend of shifting from morning to evening hours, and becomes highest in a non-summer month

Average Real-time 1-hour Net-Load Ramps

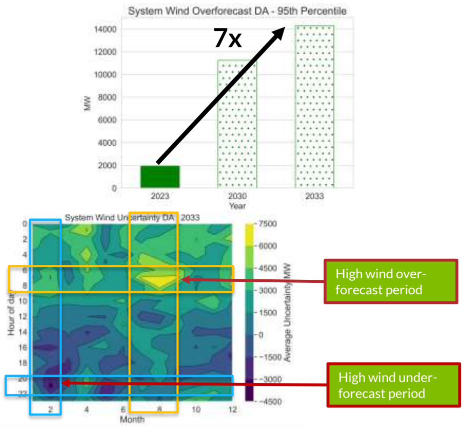
2023	2030: Needs Increase 2.5x*	2033: Needs Increase 3x*



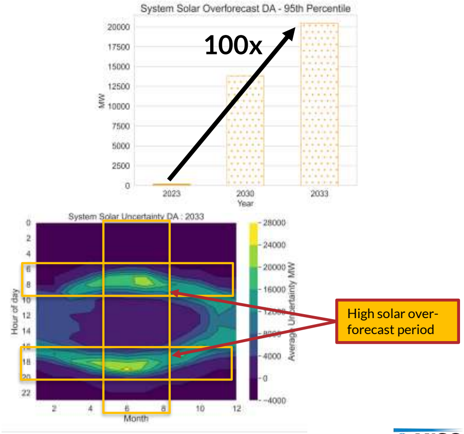
*Compared to 2023

Increased penetration of Solar and Wind adds forecasting complexity leading to higher renewable uncertainty

Wind

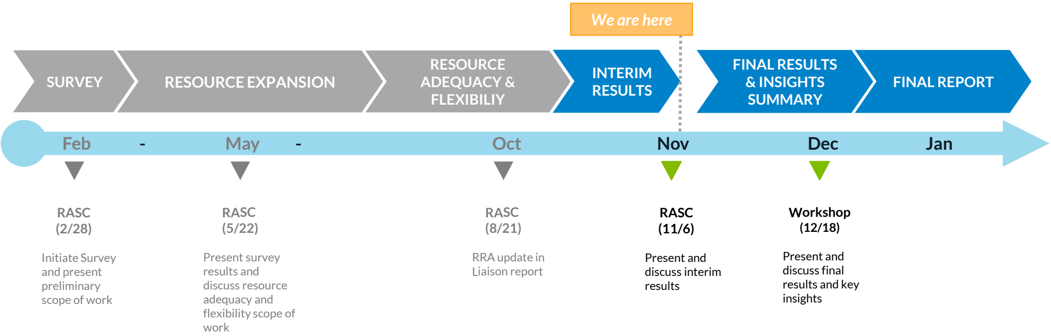


Solar



Over forecast DA = DA forecast – RT actual

MISO aims to complete the RRA technical work by December and share technical details on December 18, 2024, then publish the full report in January 2025



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MISO Contacts:
rra@misoenergy.org

Appendix

Appendix 2: This year's process incorporates seasonal requirements, seasonal accreditation based on Direct Loss of Load (DLOL), and chronological expansion

Process improvement	Previous Versions of RRA	2024 RRA (Once Final)
Renewable Portfolio Standard (RPS), Clean Energy Standard (CES) & CO_2 modeling	Aggregated approach	**State & Company-level**
Planning Reserve Margin (PRM)	Annual/PRM	**Seasonal/PRM**
Accreditation	Annual/Average ELCC based on "previous year" RRA	**DLOL vs. Installed Capacity (ICAP) function based on 2023 Attributes work (In progress)**
Resource adequacy	1 calibration	**Several calibrations (In progress)**
Chronology	Not captured	**Included (3 days/month)**
Flexibility Assessment	Included	**Included**

**Software changed from 2023 RRA: Model-built resources based on PLEXOS's long-term (LT) simulations*
RPS: Renewable Portfolio Standard PRM: Planning Reserve Margin ICAP: Installed Capacity DLOL: Direct Loss of Load

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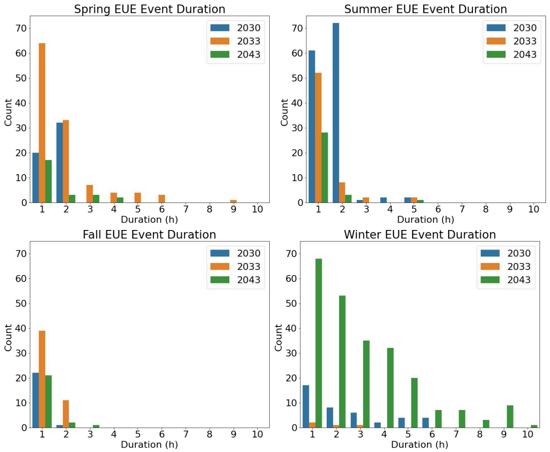
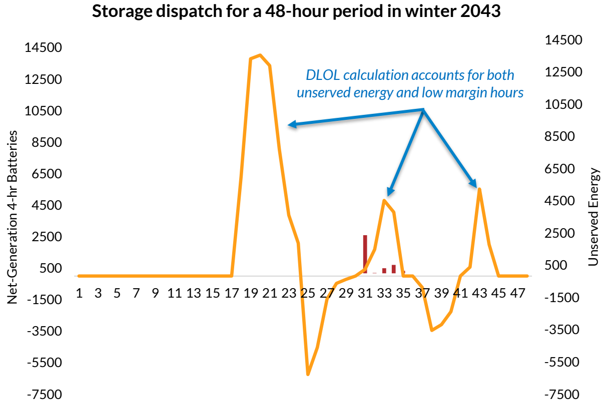
Appendix 3: Duration of EUE events by season

- Winter risk drove 2043 annual risk distribution, drastically increasing the duration of EUE events in winter
- Lower accreditation of battery in winter correlates to higher duration of EUE events in all study years
- Spring 2033 included higher thermal maintenance outage compared to 2030, resulting to increased duration of EUE events



Appendix 4: 4-hour battery storage dispatch assumptions

- 2-day optimization (hourly)
- Price-responsive variable (free)*
- Variable O&M cost = $0/MWh
- State of charge is carried over to the next day
- Round trip efficiency = 85%
- Accreditation includes periods of loss of load & critical hours (in alignment with the FERC filing)



*Impact of other storage dispatch strategies will be covered in the December workshop (e.g., greedy, minimize LOLH, minimize residual shortfall)

Appendix 5: DLOL by fuel class (%)

		Coal	Oil	Gas	Nuclear	Hydro	Other	Combined Cycle	4-hour Battery	Wind	Solar
2030	Spring	58.80	37.54	65.39	72.21	66.97	60.40	65.39	97.29	10.65	2.68
	Summer	82.09	73.02	78.35	91.38	87.47	83.11	81.21	96.12	10.52	4.80
	Fall	77.24	53.29	71.72	89.26	77.37	79.58	72.05	99.83	11.21	2.98
	Winter	90.02	16.64	76.54	96.08	77.12	88.47	92.28	79.49	10.83	0.60
2033	Spring	52.50	67.78	64.50	72.50	61.75	59.98	62.35	81.03	9.60	2.96
	Summer	82.72	74.36	78.38	89.64	84.98	82.48	79.61	95.58	9.71	4.81
	Fall	80.02	64.98	71.54	88.52	80.82	79.69	71.14	94.66	13.47	3.63
	Winter	89.16	14.38	76.81	95.52	66.31	86.96	92.54	77.42	14.63	0.36
2043	Spring	53.12	8.76	54.96	66.74	60.61	27.58	67.79	74.69	11.38	0.97
	Summer	84.38	3.19	52.52	91.10	67.41	22.28	78.96	82.39	8.43	1.80
	Fall	78.98	3.34	32.89	88.04	68.62	11.87	71.10	76.61	8.66	0.95
	Winter	89.41	43.59	69.21	95.05	65.32	74.39	94.27	31.01	11.47	0.31

"Other" includes ST Renewable, IC Renewable

Appendix 6: ICAP by fuel class (MW)

Study Year	Battery	Coal	Combined Cycle	Gas	Hydro	Nuclear	Oil	Other	Solar	Wind	Demand Response
2030	15378	29514	49983	43424	5666	15044	1912	926	64356	90202	9217
2033	22649	23179	52382	43101	5521	15044	1755	926	75218	98542	9394
2043	52681	18872	49969	40905	5368	12210	1755	825	134079	180172	10089

Highlights

- MISO has committed to publishing indicative accreditation results based on the Direct Loss of Load (DLOL) methodology prior to each Planning Resource Auction, starting with Planning Year (PY) 2025-2026, until the DLOL methodology is implemented in Planning Year 2028-2029.

- Results under the DLOL methodology include indicative Resource Class-level Unforced Capacity (UCAP), Planning Reserve Margin Requirement (PRMR), and Local Reliability Requirements (LRRs). Indicative Schedule 53A Seasonal Accredited Capacity (SAC) values for resources are also available to request.

- Results include updates made to storage modeling and demand response dispatch as presented at the April 2025 Resource Adequacy Subcommittee (RASC). MISO's recommended storage dispatch methodology, Even Loss, will be implemented in the PY 2026-2027 LOLE Study and is reflected throughout the results.

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Introduction

In compliance with Schedule 53A of the MISO Tariff, MISO performed indicative Resource Class-level UCAP and PRMR calculations, using the Planning Year 2025-2026 Loss of Load Expectation (LOLE) study models. Indicative LRRs and indicative Schedule 53A Seasonal Accredited Capacity (SAC) values for resources are available to request.

The Direct Loss of Load (DLOL) methodology will be first implemented in the Planning Year 2028-2029. MISO published a Resource Accreditation White Paper which describes the methodology in detail. A summary of the calculation steps from the white paper are provided in the diagram below.

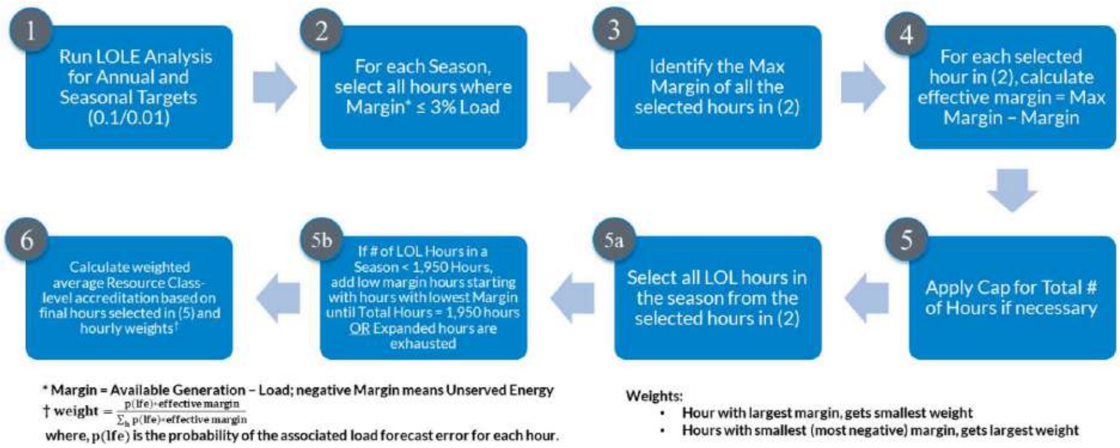


Figure 1: Direct Loss of Load calculation process diagram (Source: Resource Accreditation White Paper Version 2.1)

Updated Indicative Resource Class-level UCAP (DLOL) Results

Indicative Resource Class-level UCAP based upon the DLOL methodology and expressed as a percentage of installed capacity (ICAP) are:

PY 2025-2026	Summer	Fall	Winter	Spring
Biomass	52%	47%	51%	49%
Coal	89%	85%	76%	72%
Dual Fuel Oil/Gas	87%	84%	79%	77%
Gas	88%	85%	64%	68%
Combined Cycle	95%	92%	77%	78%
Nuclear	94%	91%	90%	81%
Oil	77%	75%	74%	73%
Pumped Storage	98%	93%	77%	66%
Reservoir Hydro	89%	82%	76%	70%
Run-of-River Hydro	62%	52%	58%	63%
Solar	45%	28%	19%	28%
Wind	8%	15%	23%	15%
Storage*	61%	88%	85%	90%

<u>*Storage modeling considerations:</u>

- *Storage was modeled using the Even Loss dispatch, along with general storage and demand response dispatch updates, as presented at the April 2025 RASC.
- All storage results assume 4-hour capability.
- Even Loss is MISO's recommended methodology and will be implemented in the PY 2026-2027 LOLE Study.

<u>Modeling Improvements:</u>

- Storage modeling has been updated since the PY 2023-2024 indicative DLOL values were calculated. For PY 2023-2024, storage was modeled as must-run units with a flat 5% forced outage rate. This study models storage more realistically as energy limited resources that discharge during high-risk hours and charge during low-risk hours.
- Thermal results reflect an improved alignment of planned maintenance with historical rates across resource classes, as MISO presented at the July Resource Adequacy Subcommittee.

Updated Indicative PRMR (DLOL) Results

Indicative Resource Class-level UCAP in MW, PRMR in MW, and Planning Reserve Margin (PRM) expressed as a percentage of MISO system peak demand, based upon the Direct Loss of Load (DLOL) are:

PY 2025-2026	Summer	Fall	Winter	Spring	Formula Key
Biomass	273	279	258	252	[A]
Coal	35,100	33,268	29,017	27,844	[B]
Dual Fuel Oil/Gas	6,591	6,550	6,791	6,055	[C]
Gas	20,354	20,016	16,634	16,568	[D]
Combined Cycle	28,822	28,377	26,485	24,663	[E]
Nuclear	11,963	11,575	11,708	10,399	[F]
Oil	1,263	1,270	1,542	1,266	[G]
Pumped Storage	2,565	2,473	2,019	1,672	[H]
Reservoir Hydro	1,857	1,387	886	856	[I]
Run-of-River Hydro	721	592	646	707	[J]
Solar	3,388	2,128	1,448	2,485	[K]
Wind	2,334	4,198	6,414	4,202	[L]
Storage	62	89	86	338	[M]
Total Unforced Capacity	115,293	112,202	103,935	97,307	[N] = Sum of [A] thru [M]
Adj. {1d in 10yr}	(2,740)	(9,680)	(6,500)	(10,375)	[O]
Firm External Support UCAP	1,935	2,215	2,594	2,309	[P]
BTMG	4,050	3,661	3,158	4,032	[Q]
Demand Response	7,852	6,220	6,504	6,370	[R]
MISO UCAP PRMR (MW)	126,390	114,618	109,692	99,643	[S] = Sum of [N] thru [R]
MISO System Peak Demand (MW)	123,576	108,109	103,910	98,680	[T]
MISO UCAP PRM %	2.3%	6.0%	5.6%	1.0%	[U] = ([S]-[T])/[T]

The adjustment to planned maintenance modeling for the indicative Resource Class-level UCAP results does not impact PRMR, since the total MW of planned maintenance remains the same and is only allocated across resource classes. PRMR results reflect Even Loss dispatch for storage.

Local Reliability Requirement (LRR) Results

Indicative LRR results under the DLOL methodology are:

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
PY 2025-2026 Indicative DLOL Local Reliability Requirements										
Summer	107.1%	105.2%	109.7%	126.9%	134.7%	118.6%	106.8%	135.9%	107.5%	143.8%
Fall	110.3%	109.9%	130.0%	121.1%	137.1%	121.5%	112.9%	138.1%	118.8%	153.2%
Winter	116.3%	117.6%	142.0%	128.5%	133.3%	113.7%	117.3%	141.7%	110.4%	151.6%
Spring	85.1%	84.0%	90.0%	111.8%	153.9%	107.3%	81.1%	90.2%	91.9%	118.5%

MPSC Case No: U-22058

Requester: CEOMEIBCIEI

Question No.: CEOMEIBCIEIDE-1.3c

Respondent: N. Foley

Page: 1 of 1

Question: 3. Refer to the direct testimony of Neal Foley at page 23, lines 14–18. c. Please explain if additional energy storage and renewable resource projects can be deployed under the Clean Capacity Accelerator Agreement.

Answer: No. See Exhibit F of the CCAA which stipulates that the Company can deploy up to 480 MW of energy storage (comprised of up to 425 MW of 4-hour energy storge and up to 55 MW of long-duration storage) and up to 1,600 MW of renewable energy projects under the CCAA. The Company cannot deploy more than these amounts.

Attachment: *None*

MPSC Case No: U-22058	
Requester: MNS	
Question No.: MNSDE-1.2b	
Respondent: N. Foley	
Page: 1 of 1	

Question: 2. Please refer to the Direct Testimony of Neal Foley, p. 19 lines 18-20. b. What categories of "avoided costs realized through the Contracts" will DTE consider as part of "aggregate benefits?"

Answer: The Company considers as "avoided costs realized through the Contracts" any revenue requirement associated with resources that the Company was able to avoid deploying due to serving the Customer's load under the PSA and CCAA.

For example:

- As described by Witness Burgdorf, the Company's modeling indicates that it can avoid deploying 500 MW of energy storage in 2035 and 2036 due to serving the Customer's load under the PSA and CCAA.
- As described by Witness Bilyeu, the Company's modeling indicates it can avoid deploying 250 MW of renewable energy by 2034 due to serving the Customer's load under the PSA and CCAA.

The Company notes that its upcoming IRP filing will include a comparison of resource needs and associated costs with and without the Customer's load.

Attachment: *None*

Co-respondent(s): K. Bilyeu, S. Burgdorf

LEE SHAVER

Senior Energy Analyst | Union of Concerned Scientists

As a Senior Energy Analyst, I focus on research and analysis of state and regional energy system transformation to support increasing shares of renewable energy and distributed energy resources. My work contributes to UCS' efforts to reform wholesale electricity market designs to increasing shares of clean energy technologies. I also contribute to UCS's state-focused efforts for policies that enable clean energy technologies, including distribution grid planning and equitable energy storage. This work supports the transition toward sustainable energy systems with high shares of renewables and distributed energy resources.

PRIOR EXPERIENCE

Slipstream — Feb. 2018 - Jan. 2024

Senior Energy Engineer (Nov. 2022 - Jan. 2024)
Energy Engineer II (Feb. 2018 - Nov. 2022)

- Proposal writer, project manager, outreach lead, and subject matter expert for research studies of distributed energy resources and emerging technologies in energy efficiency and load management in commercial buildings for resilience, grid stability, and utility cost savings.
- Managed budgets and contracts up to $2M across multiple complex projects through collaboration, effective communication, attention to detail, and flexibility to ensure timelines and objectives are exceeded.
- Partnered with two machine learning startups for pilot studies on commercial refrigeration system controls, using field data and energy modeling to verify the demand and energy savings potential.
- Advised building design teams on best practices for energy efficiency measures in new buildings using energy modeling in eQuest and Sketchbox, resulting in 50+ new commercial buildings exceeding energy code baseline (IECC, ASHRAE 90.1) and receiving utility incentives.
- Promoted equity internally through co-chairing the DEI employee resource group as well as externally by creating an audit to develop recommendations for measuring and increasing the equity impact of projects.

PA Consulting Group, *Consultant Analyst, Global Energy and Utilities* — Jun. 2017 - Jan. 2018

- Advised utilities and power producers using technical, policy, financial, and market analysis to quantify risk, evaluate assets, and improve operations.
- Performed market research and policy analysis across MISO, PJM, ERCOT, and CAISO, including market and environmental regulations, infrastructure development, and economic forecasts.

University of Wisconsin-Madison, *Research Assistant* — Aug. 2014 - May 2017

- Developed, tested, and documented a solution for rural home electrification by designing hardware and software for a modular, home-scale dc microgrid.
- Partnered with the National Institute of Engineering in Mysuru, India to implement a microgrid testbed and identify locations for field testing.

Quadlogic Controls, *Sales and Specification Engineer* — Jul. 2013 - Aug. 2014

- Coordinated manufacturer's representatives in 13 states to drive sales through networking, outreach, trade shows, and technical seminars.
- Lead updates of product manuals and specifications using technical writing and editing skills to provide improved support to clients and partners.

Energy Spectrum, *Project Manager* — Oct. 2012 - Jul. 2013

- Supported successful participation in grid operator and utility demand response programs by specifying, commissioning, and managing electric submetering systems.
- Managed turn-key upgrade of 500+ electric submeters at an industrial/commercial complex in Brooklyn from quotation to daily operation, resulting in increased submetering revenue.

Quadlogic Controls — Dec. 2009 - Oct. 2012

Assistant Engineering Manager (May 2012 – Oct 2012)

- Coordinated operations of tech support, commissioning, and field service.
- Managed a new team of seven including technicians, engineers, and a service dispatcher resulting in improved customer service and faster completion of commissioning projects.

Field Engineering Supervisor (Jul 2010 – May 2012)
- Developed and facilitated training seminars to certify service providers in the US and Canada, resulting in expansion of service range to five new markets and reduction in service call response time and costs by 20%.
- Implemented a CRM system for field service, repairs, and tech support resulting in reduced response time with no increase in workforce.

Technical Support Engineer (Dec 2009 – Jul 2010)
- Conducted long term diagnostic studies on problematic issues and developed Engineering Change Orders to implement proposed solutions.

United States Peace Corps, El Salvador, *Municipal Development Volunteer* Jun. 2007 - Jul. 2009
- Cultivated a deep understanding of community strengths and needs to support several community groups in fundraising for computer labs, soccer stadiums, and community events.

EDUCATION & CERTIFICATES
- M.S. in Electrical Engineering (Energy & Power Systems), *University of Wisconsin-Madison*
- Energy Analysis & Policy Graduate Certificate, *University of Wisconsin-Madison*
- B.S. in Electrical Engineering, *LeTourneau University*

SELECTED PUBLICATIONS
- S. Clemmer, M. Chavez, S. Dotson, J. Gignac, S. Sattler, and **L. Shaver**. *Data Center Power Play: How Clean Energy Can Meet Rising Electicity Demand While Delivering Climate and Health Benefits*. Union of Concerned Scientists, 2026.
- S. Dotson, **L. Shaver**, and J. Gignac. *Storing the Future: A Modeling Analysis of Illinois Storage Needs*. Union of Concerned Scientists, 2024.
- M. Koolbeck, **L. Shaver**, and J. LeZaks, "Weathering the storm: Microgrid feasibility studies for municipal applications". ACEEE Summer Study on Energy Efficiency in Buildings, 2022.
- "Chapter 9: Microgrids," ASHRAE *Smart Grid Application guide: Integrating Facilities with the Electric Grid*, 2020.

SELECTED TESTIMONY
- Direct testimony on behalf of UCS, Environmental Defense Fund, ELPC, NRDC, and Vote Solar, *Ameren Illinois Company Petition for Approval of Multi-Year Integrated Grid Plan pursuant to 220 ILCS 5/16-105.17*, Illinois Commerce Commission, Case No. 26-0051, 2026.
- Direct and rebuttal testimony on behalf of UCS, the Ecology Center, ELPC, and Vote Solar, *In the matter of the application of Indiana Michigan Power Company for approval of modifications to its Large Power Tariff*, Michigan Public Service Commission, Case No. U-21986, 2026.
- Direct testimony on behalf of UCS, the Ecology Center, ELPC, and Vote Solar, *In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief*, Michigan Public Service Commission, Case No. U-21870, 2025.
- Direct and rebuttal testimony on behalf of UCS, the Ecology Center, ELPC, and Vote Solar, *In the matter of Consumers Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023*, Michigan Public Service Commission, Case No. U-21816, 2025.
- Direct and rebuttal testimony on behalf of UCS, the Ecology Center, ELPC, and Vote Solar, *In the matter of the application of DTE Electric Company for approval of Interconnection Procedures and Waivers from Interconnection and Distributed Generation Standards R 460.901a*, Michigan Public Service Commission, Case No. U-21482, 2024.

PROFESSIONAL ASSOCIATIONS & INDUSTRY INVOLVEMENT
- Wisconsin Distributed Resources Consortium (WIDRC), *Treasurer*
- IEEE, *Member*
- SEPA Microgrid Working Group, *Member*
- Wisconsin PSC 119 interconnection rulemaking advisory committee, *Member*

MPSC Case No: U-22058	
Requester: AG	
Question No.: AGDE-2.50b	
Respondent: K. Bilyeu	
Page: 1 of 1	

Question: 50. Refer to page 9 of Mr. Bilyeu's direct testimony on the VGP program, portfolio of renewable energy projects, and load calculation. b. Explain why in calculating the annual load of 7,884 GWh the Company used a load factor of 88.5% and not 100%.

Answer: The 88.5% stated in the footnote on page 9 of my direct testimony was stated in error. The correct load factor corresponding to an annual load of 7,884 GWh is approximately 90%, calculated as 7,884 GWh divided by 8,760 hours. The 90% load factor was provided to the Company as an estimate from the Customer.

Attachment: *None.*

CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22058

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.12	
Respondent: S. Burgdorf	
Page: 1 of 1	

Question: 12. Refer to the direct testimony of Shawn Burgdorf at page 6, lines 23–24, and page 7, lines 4–12. Please provide the EnCompass input database, EnCompass modeling outputs, and any post-processing spreadsheets, for each case modeled in EnCompass.

Answer: See attachments for input and output files. Exhibits and Workpapers for Witness Burgdorf were provided in response to discovery question CEOMEIBCIEIDE-1.25.

NOTE: This response contains confidential data. Subject to entry of a protective order in this matter, confidential responses and any attachments thereto will be provided to parties who sign nondisclosure certificates.

Attachment: NDA U-22058 CEOMEIBCIEIDE-1.12 Base CE Inputs CONFIDENTIAL.xls
NDA U-22058 CEOMEIBCIEIDE-1.12 Base PC Inputs CONFIDENTIAL.xls
NDA U-22058 CEOMEIBCIEIDE-1.12 DC2 CE Inputs CONFIDENTIAL.xls
NDA U-22058 CEOMEIBCIEIDE-1.12 DC2 PC Inputs CONFIDENTIAL.xls
NDA U-22058 CEOMEIBCIEIDE-1.12 Base Output Reports CONFIDENTIAL.xls
NDA U-22058 CEOMEIBCIEIDE-1.12 DC2 Output Reports CONFIDENTIAL.xls

Co-respondent: Legal

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.28a	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 28. Refer to the direct testimony of Justin Brooks at page 6, lines 3–5: “The resource adequacy study that I performed is designed to evaluate whether the output of the complex capacity expansion modeling process meets the specified level of resource adequacy.” a. Were additional studies beyond the resource adequacy study performed to assess the Customer’s impact on DTE’s grid? Such studies may include screening studies, system impact studies, and facilities studies.

Answer: Yes, grid impact studies were conducted at the transmission level by ITC.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.28ai	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 28. Refer to the direct testimony of Justin Brooks at page 6, lines 3–5: “The resource adequacy study that I performed is designed to evaluate whether the output of the complex capacity expansion modeling process meets the specified level of resource adequacy.” a. Were additional studies beyond the resource adequacy study performed to assess the Customer’s impact on DTE’s grid? Such studies may include screening studies, system impact studies, and facilities studies. i. If yes, please list and describe which studies were performed, and comment on the results.

Answer: See CEOMEIBCIEIDE-1.28a. These studies included steady-state thermal and voltage analysis, short circuit and stability analysis.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-2.1d	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 1. Please refer to the Company's response to question number CEOMEIBCIEIDE-1.37b, which states: "To safeguard the electric system, DTE is developing a set of operating parameters which the customer must abide by. This includes but is not limited to ramprate, load oscillation limitations, ride-thru requirements and harmonics." Please also refer to the Company's response to question number CEOMEIBCIEIDE-1.38a, which states "These technical interconnection requirements are addressed in the Company's initial operating parameters that will be established with the Customer, which is subject to input from the Customer, MISO and ITC."

d. Are there specific recommendations from the Customer, MISO, ITC, or another source that are serving as a basis for the operating parameters? If so, please provide a link and/or copy of any such materials.

Answer: DTE Electric has historically required new customers to follow a series of operating limits including but not limited to in-rush frequency/magnitude, and power factor. As the Company has learned about the relatively new operating characteristics of certain large data center customers, it was determined that a more robust set of guidelines were required to safeguard the electric system. While a broad set of requirements does not yet exist within the industry, aspects we have incorporated into our Operating Parameters document can be found in references such as: Power Stabilization for AI Training Datacenters which discusses some of the power management challenges associated with data center operations. DTE Electric is also participating in the MISO Large Load Working Group.

Attachment: *none*

MPSC Case No: U-22058

Requester: CEOMEIBCIEI

Question No.: CEOMEIBCIEIDE-1.37b

Respondent: S. Benyard

Page: 1 of 1

Question: 37. Refer to the November 21, 2025 comments of DTE in FERC Docket RM26-4-000, available at https://elibrary.ferc.gov/eLibrary/filelist?accession_num=20251121-5351. b. On page 18, the Company states "Operationally, the largest loads pose distinct planning and reliability challenges—abrupt ramps, concentrated nodal demand, and sensitivity to upstream contingencies—that justify a bespoke federal framework." Please describe in more detail the "reliability challenges" that are being referred to here, and how the Company has addressed these risks from the Customer in the instant docket.

Answer: Reliability challenges refer to both a reliable service for the new customer which was addressed through a minimum (n-1) level of design for the transmission and substation, as well as continued reliable service for the larger electric system. To safeguard the electric system, DTE is developing a set of operating parameters which the customer must abide by. This includes but is not limited to ramp-rate, load oscillation limitations, ride-thru requirements and harmonics.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.38a	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 38. Refer to pages 43–46 of the Elevate Energy Consulting and GridLab report “Practical Guidance and Considerations for Large Load Interconnections,” available at: https://gridlab.org/portfolio-item/practical-guidance-and-considerations-for-large-load-interconnections/. The referenced pages describe the following 18 categories of technical requirements recommended for interconnection of large loads to the transmission system: Load Interconnection Size Limits; Model Sharing; Data Recording and Monitoring; Voltage and Frequency Ride-Through; Power Factor and Reactive Power; Power Quality; Oscillation; Short-Circuit; Protection; Data Sharing; Operations and Control; Communications with Utility; Emergency Response and Coordination; Operations and Maintenance; Backup Generation; Demand Response; Cybersecurity; and Utility Right to Monitor and Enforce Compliance. For each category on this list, please answer the following questions: a. Will the Company mandate this requirement for the Customer?

Answer: These technical interconnection requirements are addressed in the Company’s initial operating parameters that will be established with the Customer, which is subject to input from the Customer, MISO and ITC. The Company will also ensure Cybersecurity is reviewed through its normal internal processes.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-2.1c	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 1. Please refer to the Company's response to question number CEOMEIBCIEIDE-1.37b, which states: "To safeguard the electric system, DTE is developing a set of operating parameters which the customer must abide by. This includes but is not limited to ramprate, load oscillation limitations, ride-thru requirements and harmonics." Please also refer to the Company's response to question number CEOMEIBCIEIDE-1.38a, which states "These technical interconnection requirements are addressed in the Company's initial operating parameters that will be established with the Customer, which is subject to input from the Customer, MISO and ITC."

c. If not, please provide a draft of the parameters.

Answer: See attachment NDA_U-22058 CEOMEIBCIEIDE-2.1c Confidential.

Attachment: NDA_U-22058 CEOMEIBCIEIDE-2.1c Confidential

U-22058

Attachment NDA_U-22058 CEOMEIBCIEIDE-2.1c_Confidential to Exhibit MEICEO-24 is confidential and filed under seal

U-22058

Exhibit MEICEO-25 is confidential and filed under seal

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.39a	
Respondent: A. Willis	
Page: 1 of 1	

Question: 39. Refer to DTE's application in Case No. U-22059, available at: https://mi-psc.my.site.com/s/filing/a00cs00001cYmGkAAK/u220590001. On page 2, the application quotes from the order in Case No. U-21990 which includes the requirement that "the company will shed firm load from the facility operated by Green Chile Ventures LLC prior to shedding firm load of any of DTE Electric Company's other customers." On page 1 of Attachment A, DTE revises the Emergency Electrical Procedures with a load shedding provision applicable to "Customers that take service from DTE Electric after October 1, 2025 with capacity of at least 500MW or customers that take service under the Large Load Provision of Rate Schedule No. D11." a. Please explain why DTE chose to make the load shed provision applicable to all large load customers, and not narrowly focused on Green Chile Ventures as directed in the order.

Answer: The Company endeavors to treat all similarly situated customers similarly. The U-21990 order did not exclude loads beyond Green Chili Ventures from the required updates to the emergency electrical procedures.

Attachment: *None*

MPSC Case No: U-22058

Requester: CEOMEIBCIEI

Question No.: CEOMEIBCIEIDE-1.39b

Respondent: A. Willis

Page: 1 of 1

Question: 39. Refer to DTE's application in Case No. U-22059, available at: https://mi-psc.my.site.com/s/filing/a00cs00001cYmGkAAK/u220590001. On page 2, the application quotes from the order in Case No. U-21990 which includes the requirement that "the company will shed firm load from the facility operated by Green Chile Ventures LLC prior to shedding firm load of any of DTE Electric Company's other customers." On page 1 of Attachment A, DTE revises the Emergency Electrical Procedures with a load shedding provision applicable to "Customers that take service from DTE Electric after October 1, 2025 with capacity of at least 500MW or customers that take service under the Large Load Provision of Rate Schedule No. D11." b. Will this provision also apply to Google LLC, the Customer in the instant docket? Why or why not?

Answer: Yes. Google LLC is taking service after October 1, 2025 and is greater than 500 MW.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEO	
Question No.: CEOMEIBCIEIDE-3.2	
Respondent: K. Bilyeu	
Page: 1 of 1	

Question: 2. Refer to Exhibit A-2. The native excel file does not include formulas for line 37, and the included workpapers do not indicate the source of the data on line 37. Please provide a copy of Exhibit A-2 including formulas for line 37, and/or provide an additional workpaper demonstrating how the data in line 37 was calculated.

Answer: Please refer to attachment *U-22058 CEOMEIBCIEIDE-3.2 REC Balance*, which includes additional lines to show the formula for the REC balance. It is calculated in the same method as Line 29, but with additional generated RECs related to the 1800 MW approved for the customer in U-21990, and 1600 MW of VGP and a reduction of 250 MW as requested in this case.

Attachment: *U-22058 CEOMEIBCIEIDE-3.2 REC Balance*

Michigan Public Service Commission
DTE Electric Company
Renewable Portfolio Standard Compliance Summary
U-22058 CEOMEIBCIEIDE-3.2 REC Balance

Case No.: U-22058
Exhibit: A-2
Witness: K.L. Bilyeu
Page: 1 of 2
CEOMEIBCIEIDE-3.2

Case No.: U-22058
Exhibit: A-2
Witness: K.L. Bilyeu
Page: 2 of 2

Line No.	(a)	(b)	(c) 2026	(d) 2027	(e) 2028	(f) 2029	(g) 2030	(h) 2031	(i) 2032	(j) 2033	(k) 2034	(l) 2035
1	**Sales and Requirement Calculation**	**Source**										
2	**Method: Weather Normalized or 3 Year Average**											
3	If Selected Weather Normalized:											
4	Current Year Sales to Retail Customers	U-21662 Exh A-29 Column (i)	39.634.892	39.497.918	39.869.525	39.910.589	40.013.252	40.203.583	40.511.120	40.702.673	41.076.945	41.418.790
5	Incremental First Data Center Customer Load	U-21990	3.285	5,031,963	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572
6	Incremental Second Data Center Customer Load	WP-1	-	33.480	3.300.480	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000
7	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy		-	-	-	-	-	-	-	-	-	-
8	Current Year Weather Normalization Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	Less VGP sales	U-21662 WP-6	2.794.617	5.358.090	6.616.223	7.426.909	7.415.003	7.385.969	7.375.761	7.328.315	7.299.690	7.271.202
10	Less Incremental VGP Sales	WP-1	-	-	-	-	997.527	2.398.048	3.203.084	3.178.360	3.162.468	3.146.656
11	Less Outflow from DG Customers	U-21662 Exh A-29 Column (i)	55.355	68.099	83.171	100.829	121.202	143.020	164.705	185.876	204.715	222.048
12	Current Year Weather Normalized Sales	Calculated	36.788.205	39.137.172	47.374.183	51.170.422	50.267.091	49.064.118	48.555.143	48.797.693	49.197.643	49.566.457
13	If Selected 3 Year Average:											
14	Current Year Retail Sales to Retail Customers											
15	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy											
16	Less VGP sales											
17	Less outflow from DG customers											
18	3 Year Average of sales											
19	RPS Required Energy Credits (For 2026 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	Calculated	5.667.532	5.518.231	5.870.576	7.106.127	25.585.211	25.133.545	24.532.059	24.277.571	24.398.847	29.518.586
20	**Energy Credits**											
21	Energy Credit Beginning Balance	Line 29	2.455.332	2.833.451	5.401.814	9.327.780	15.308.233	5.072.900	(2.451.067)	(8.173.568)	(11.708.730)	(13.312.505)
22	Plus: Energy Credits Obtained Through Generation/BOT	U-21662 Exh A-4 +WP-4	3.405.313	4.785.213	5.979.683	7.689.837	9.356.714	11.743.705	13.258.615	15.574.681	17.938.444	20.437.898
23	Plus: Energy Credits Obtained Through PPA	U-21662 Exh A-4 +WP-4	2.356.962	3.025.469	3.451.320	4.117.483	4.736.487	4.639.271	4.337.065	3.947.786	3.380.699	3.300.608
24	Plus: Energy Credits Obtained Through REC Purchases[1]	U-21662 Exh A-4 Line 7	283.377	275.912	365.538	1.279.261	1.256.677	1.226.603	1.213.879	1.219.942	1.475.929	1.486.994
25	Less: Energy Credits Sold		-	-	-	-	-	-	-	-	-	-
26	Available Energy Credits (Lines 21 + 22 + 23 + 24 - 25)	Calculated	8.500.983	10.920.045	15.198.356	22.414.360	30.658.111	22.682.478	16.358.491	12.568.841	11.086.342	11.912.994
27	Less: Compliance Requirement (Line 19)	Calculated	5.667.532	5.518.231	5.870.576	7.106.127	25.585.211	25.133.545	24.532.059	24.277.571	24.398.847	29.518.586
28	Less: Energy Credit Expired		-	-	-	-	-	-	-	-	-	-
29	Energy Credit Ending Balance (Lines 26 - 27 - 28)	Calculated	2.833.451	5.401.814	9.327.780	15.308.233	5.072.900	(2.451.067)	(8.173.568)	(11.708.730)	(13.312.505)	(17.605.592)
30	**Base Case without Data Center Load**											
31	RPS Required Energy Credits (For 2026 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	U-21662 Exh A-2 Line 16	5.667.532	5.517.738	5.110.759	4.975.520	16.191.425	16.238.523	16.337.297	16.485.327	16.594.241	20.143.524

Line No.	(m) 2036	(n) 2037	(o) 2038	(p) 2039	(q) 2040	(r) 2041	(s) 2042	(t) 2043	(u) 2044	(v) 2045
1										
2										
3										
4	41.796.601	41.972.411	42.220.700	42.421.326	42.654.688	42.699.590	42.849.878	43.041.817	43.325.884	43.439.572
5	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572
6	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000	7.884.000
7	-	-	-	-	-	-	-	-	-	-
8	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	7.261.222	7.214.626	7.186.536	7.158.575	7.148.812	7.103.051	7.075.484	7.048.047	7.038.504	6.993.562
10	3.139.501	3.115.268	3.099.692	3.084.193	3.077.180	3.053.429	3.038.161	3.022.971	3.016.097	2.992.817
11	239.754	257.838	276.311	295.137	313.920	332.890	352.794	373.097	393.673	414.458
12	49.943.696	50.172.251	50.445.733	50.670.992	50.902.347	50.997.792	51.171.010	51.385.273	51.665.183	51.826.308
13										
14										
15										
16										
17										
18										
19	29.739.874	29.966.218	30.103.350	30.267.440	30.402.595	30.541.408	30.598.675	30.702.606	30.831.164	30.999.110
20										
21	(17.605.592)	(20.860.040)	(21.739.132)	(20.104.865)	(16.009.553)	(9.319.900)	(238.954)	11,275,395	22,809,220	33,986,930
22	23.189.448	25.812.563	28.475.980	31.113.974	33.847.982	36.399.106	38.902.443	39.038.455	38.815.294	38.478.159
23	3.295.979	3.274.563	3.261.638	3.248.777	3.244.266	3.223.249	3.210.581	3.197.976	3.193.581	3.172.955
24	-	-	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-	-	-
26	8.879.834	8.227.086	9.998.486	14.257.886	21.082.695	30.302.455	41.874.071	53.511.826	64.818.094	75.638.043
27	29.739.874	29.966.218	30.103.350	30.267.440	30.402.595	30.541.408	30.598.675	30.702.606	30.831.164	30.999.110
28	-	-	-	-	-	-	-	-	-	-
29	(20.860.040)	(21.739.132)	(20.104.865)	(16.009.553)	(9.319.900)	(238.954)	11.275.395	22.809.220	33.986.930	44.638.934
30										
31	20.355.325	20.577.375	20.699.968	20.854.712	20.980.568	21.115.173	21.158.189	21.252.960	21.372.403	21.536.224

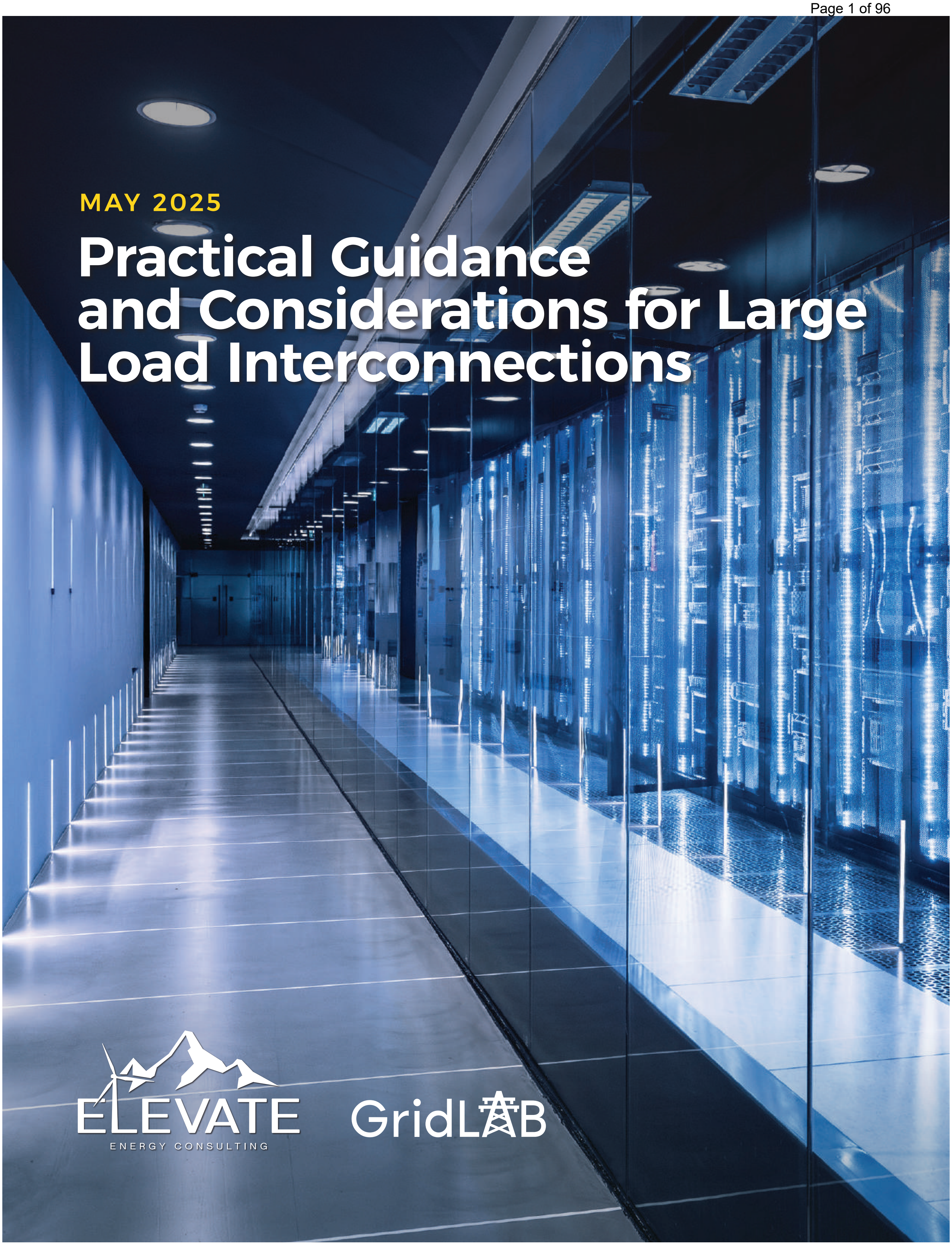
	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Data Center 1 (MWh)	3,285	5,031,963	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572
Data Center 2 (MWh)	0	33,480	3,300,480	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000
Total Data Center Load (MWh)	3,285	5,065,443	14,204,052	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572
<u>Data Center 2 - VGP Portion</u>										
Cumulative Build Capacity (MW)		0	0	0	500	1,200	1,600	1,600	1,600	1,600
Available for customer (MWh)					997,527	2,398,048	3,203,084	3,178,360	3,162,468	3,146,656

	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Data Center 1 (MWh)	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572
Data Center 2 (MWh)	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000
Total Data Center Load (MWh)	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572	18,787,572
<u>Data Center 2 - VGP Portion</u>										
Cumulative Build Capacity (MW)	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Available for customer (MWh)	3,139,501	3,115,268	3,099,692	3,084,193	3,077,180	3,053,429	3,038,161	3,022,971	3,016,097	2,992,817

	2026	2027	2028	2029	2030	2031	2032	2033	2034
2030 Data Center Solar					662.4				
2030 Data Center Solar - VGP					500.0				
2031 Data Center Solar						331.5			
2031 Data Center Solar - VGP						700.0			
2032 Data Center Solar							808.8		
2032 Data Center Solar - VGP							400.0		
2033 Data Center Solar								(200.0)	
2034 Data Center Solar									(50.0)

MAY 2025

Practical Guidance and Considerations for Large Load Interconnections



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Elevate Energy Consulting specializes in grid reliability analysis, power system modeling and studies, grid dynamics and controls, transmission planning and operations, inverter-based resource integration, large-load integration, regulatory compliance and policy, technical management consulting, and research and development.

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GridLab delivers expert capacity to solve technical grid challenges and answer reliability questions. Together, the GridLab Team and its network of 75+ power system experts provide technical expertise, resources, and education on the design, operation, and attributes of the grid.

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Executive Summary

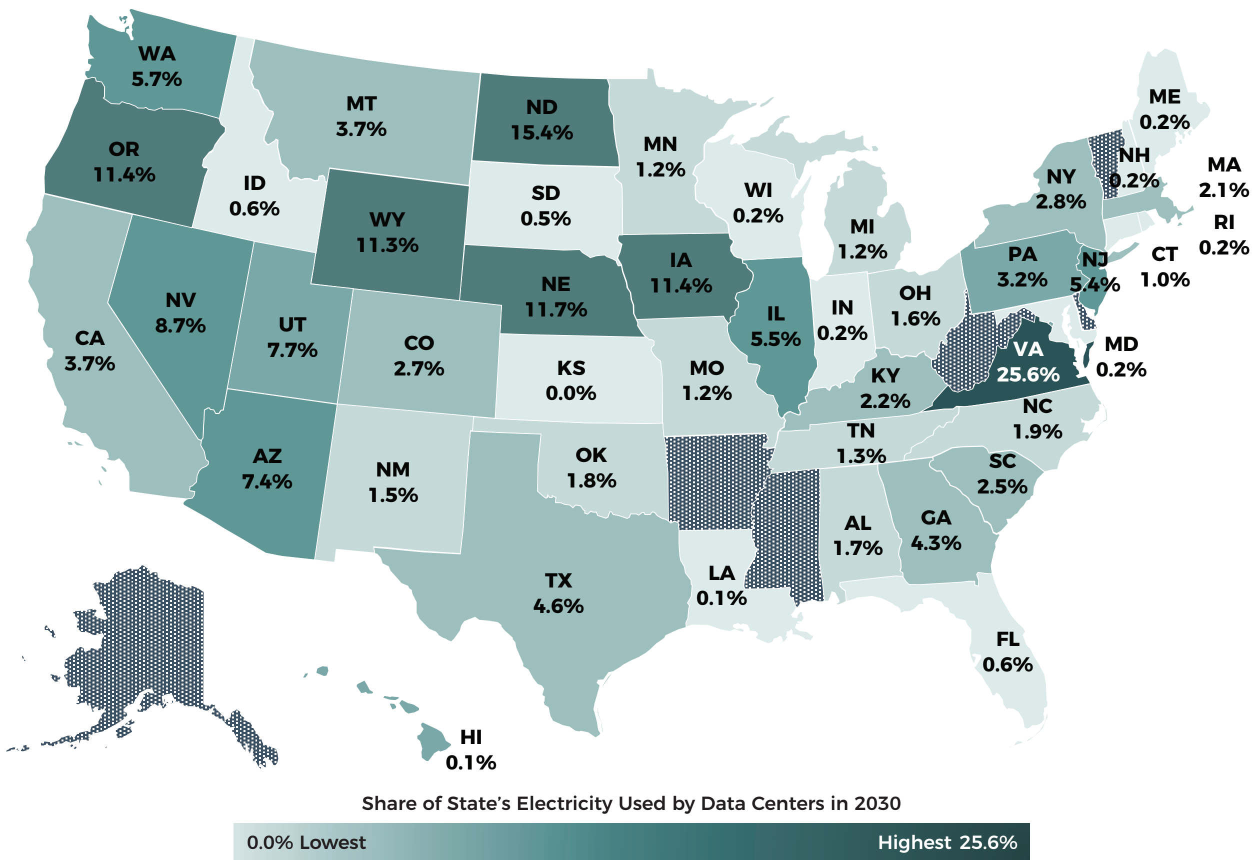
Requests to connect large data center and artificial intelligence (AI) loads are entering transmission planning processes at an unprecedented rate. This surge is driven by a combination of tax incentives, low electricity costs, access to usable land and water, available capital for AI development, and business-friendly regulatory environments. These potential data center customers are relatively price insensitive, prioritizing fast and reliable ***access to electricity as quickly as possible***. However, because transmission system capacity is not broadly transparent or readily available to industry stakeholders, developers submit speculative interconnection requests in an attempt to secure future access.

While the load interconnection queue may be speculative in nature and therefore the actual magnitude and breadth of data center development and AI energy needs is opaque, ***data centers already comprise a significant portion of electricity demand in the US (see Figure ES.1, p. 4) and this trend is expected to accelerate in the years ahead*** [1]. Utilities must evaluate and process these requests fairly and efficiently—studying available transmission capacity and identifying necessary network upgrades—while ensuring continued reliability of the bulk power system (BPS). Given the pace of load growth, the economic benefits of serving these customers, and strong political support for data center development, utilities need streamlined access to resources and recommended practices that can enable this emerging future.

Although the potential benefits to utilities are significant, the technical challenges of integrating large loads cannot be overlooked. Rigorous engineering analysis and due diligence are more critical than ever before to ensure reliable operation of the grid as these substantial loads come online.

This report serves as a practical guide to improving and harmonizing utility practices for processing, studying, and assessing large load interconnection requests. It also serves as a reference for state regulatory bodies in their effort to ensure that utility constituents are fully evaluating the potential impacts that large loads, particularly data centers, can have on grid reliability and existing customers.

FIGURE ES.1: Data Center Electricity Consumption by State



Data centers are a significant consumer of electricity in some states, and these numbers are expected to increase in the years ahead. SOURCE: ADAPTED FROM EPRI.

This guidance is especially useful in regions with limited experience integrating data centers and among utilities with constrained resources or bandwidth to stay current with evolving practices in this area.

Ensuring reliability of the BPS amid the boom in large loads requires:

- Large load customers to provide timeline and accurate data to Transmission Owners (TOs), Transmission Planners (TPs), and Planning Coordinators (PCs) to effectively plan, design, and protect the BPS.
- Large load customers to coordinate and share data with TOs, Transmission Operators (TOPs), Balancing Authorities (BAs), and Reliability Coordinators (RCs) to maintain real-time operational reliability of the BPS.

PHOTO: ISTOCKPHOTO/GERVILLE

- Enhanced communication and coordination across the transmission-distribution interface, ensuring that distribution-connected large loads follow similar requirements and processes as transmission-connected large loads due to their aggregate impact on the BPS.
- Clear and consistent performance expectations and technical requirements for large loads to ensure they contribute to rather than detract from overall BPS reliability and system performance.
- Grid planners to develop accurate models and perform comprehensive studies of BPS performance based on a well-informed understanding of large load behaviors.

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1

Background on Large Load Interconnections

The electricity sector is poised for record demands and sustained growth in the years ahead [1]. A 2023 study of nationwide demand trends found that grid planners had nearly doubled their five-year load growth forecasts from 2.6% to 4.7% in just one year [2]. This surge is fueled by both individual and aggregated end-use loads with high electricity demands. Multi-sector electrification—driven by digitalization, heat pumps, electric vehicle charging, and other factors—continues to push overall electricity demand higher. However, the primary driver of demand growth is the wave of "large load" interconnection requests to the BPS,[1] particularly from data centers [3]. Figure 1.1 (p. 9) illustrates the major categories of large loads connecting to the BPS today and anticipated in the future. This trend is placing unprecedented pressure on the BPS and the broader utility sector, emerging as one of the most significant forces reshaping the electricity industry for decades to come.

BOX 1: SERIOUS RELIABILITY RISKS TO THE GRID

Data center load uncertainty and response to grid events is not theoretical. In July 2024, a normal grid fault in Northern Virginia triggered the sudden disconnection of more than 1,500 MW of data centers across 25–30 substations. About 60 data centers switched to backup power via uninterruptible power supplies (UPS) designed to disconnect from the grid after a preset number of voltage excursions [4]. Figure 1.2 (p. 10) shows the net load reduction during the event and a simplified oneline diagram of the local substations and data center loads affected. In February 2025, an even larger 1,800 MW load loss event occurred for the same reasons. They underscore the lack of insights into data center behavior and the need for greater transparency into their operational performance.

1 The term BPS is used by the Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC) that broadly defines the interconnected transmission and sub-transmission system, excluding local distribution.

FIGURE 1.1: Drivers of Rapid Load Growth

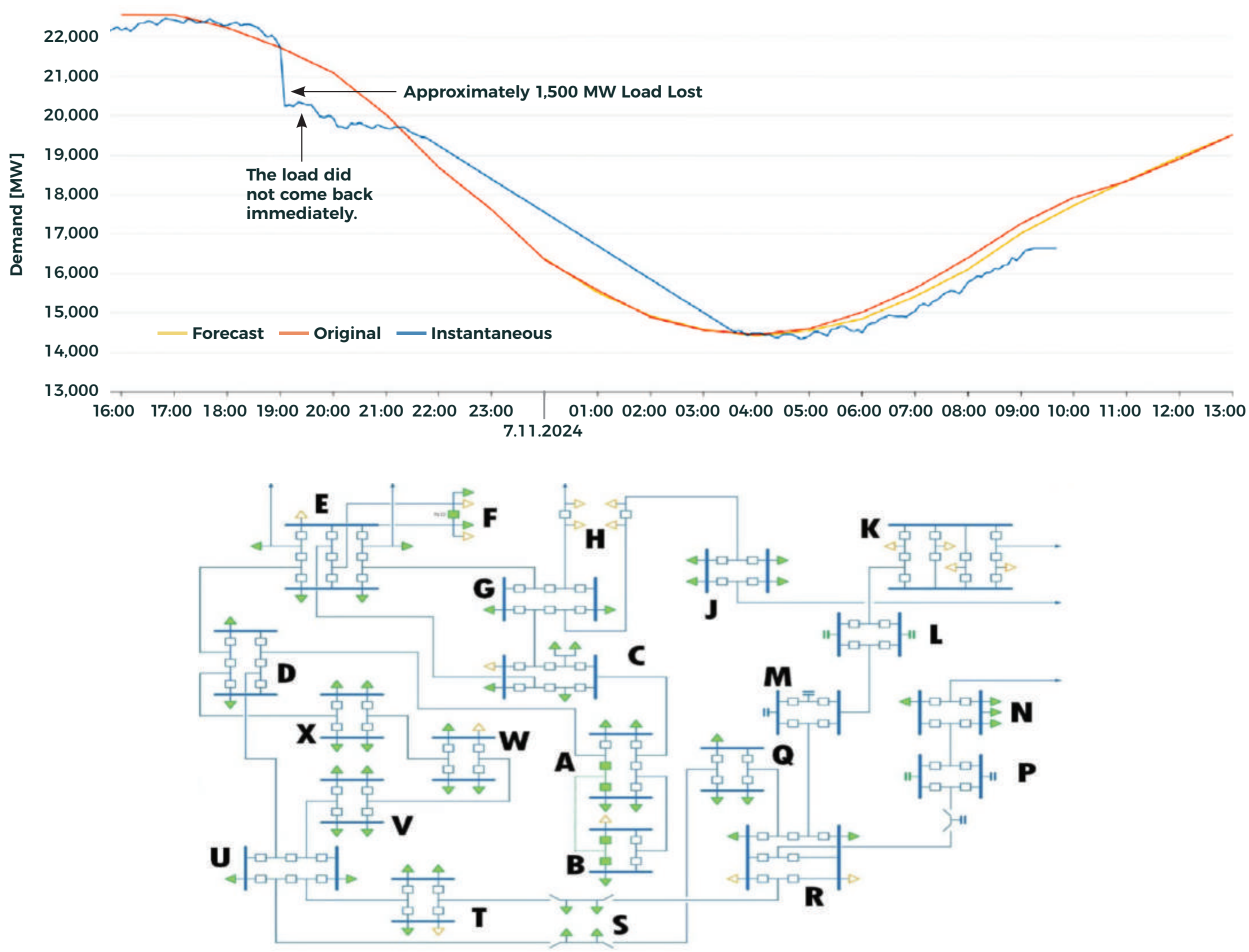
Data centers are by far the primary driver of electricity sector demand forecast growth.

SOURCE: ELEVATE ENERGY CONSULTING.

Data Centers: Large and Unpredictable

Data centers now constitute the vast majority of large load interconnection requests in the U.S. because of their immense power demands and double-digit annual capacity growth, which can present possible grid reliability risks. Unpredictable demand patterns are a primary challenge. Due to intense global competition, data center owners often keep operational and performance details private, limiting visibility into their energy needs, fluctuations, and demand ramps. This prevents utilities and grid operators from properly planning for their impact. A sudden surge or drop in demand from these facilities can pose serious reliability risks to the grid.

FIGURE 1.2: July 2024 Northern Virginia Data Center Event Visualization



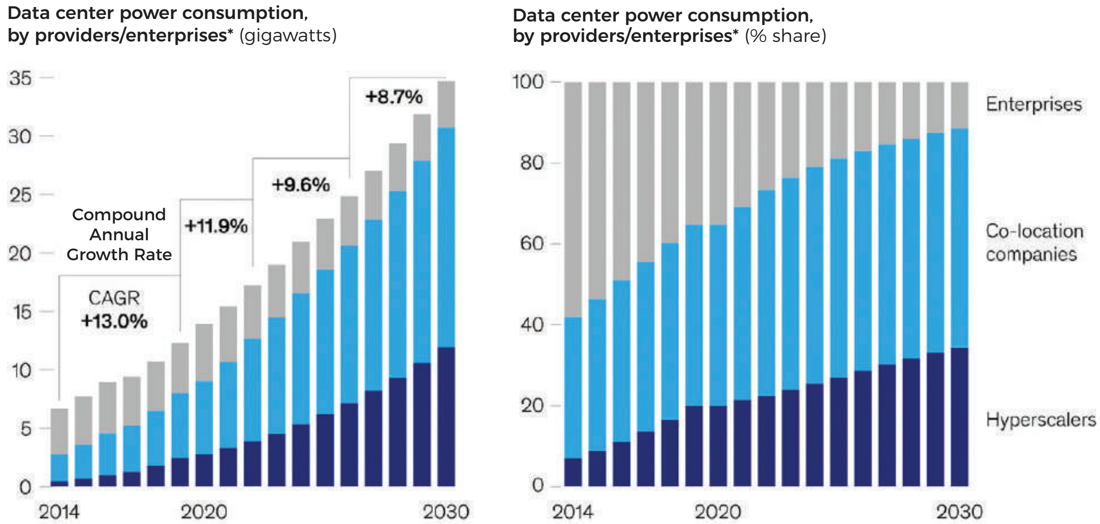
In July 2024, widespread data center disconnection caused by a sequence of grid faults resulted in a significant net load reduction in Northern Virginia. The green in the second image represents load lost during the event.

SOURCE: ADAPTED FROM NERC.

Imbalance Between Supply and Demand

The surge in large load interconnection applications is straining the electricity sector, requiring a rapid expansion of supply to keep pace with soaring demand. Data centers are the primary driver of this demand, accounting for nearly 80% of large load requests submitted to utilities across the Western U.S., Canada, and Mexico in 2024 [3]. Their rapid expansion is expected to place immense pressure on the BPS within a short timeframe. U.S. data center demand is projected to grow by nearly 10% annually, doubling from 17 gigawatts (GW) in 2022 to 35 GW by 2030 [1]. As Figure 1.3 (p. 11) illustrates, this growth is shifting away from individual enterprise facilities toward large-scale data center complexes [2]. These include co-location facilities that lease computing power to multiple businesses and hyperscale data centers dedicated to cloud computing and AI services—critical pillars of the modern economy.

FIGURE 1.3. U.S. Data Center Demand Forecasts by Type of Data Center

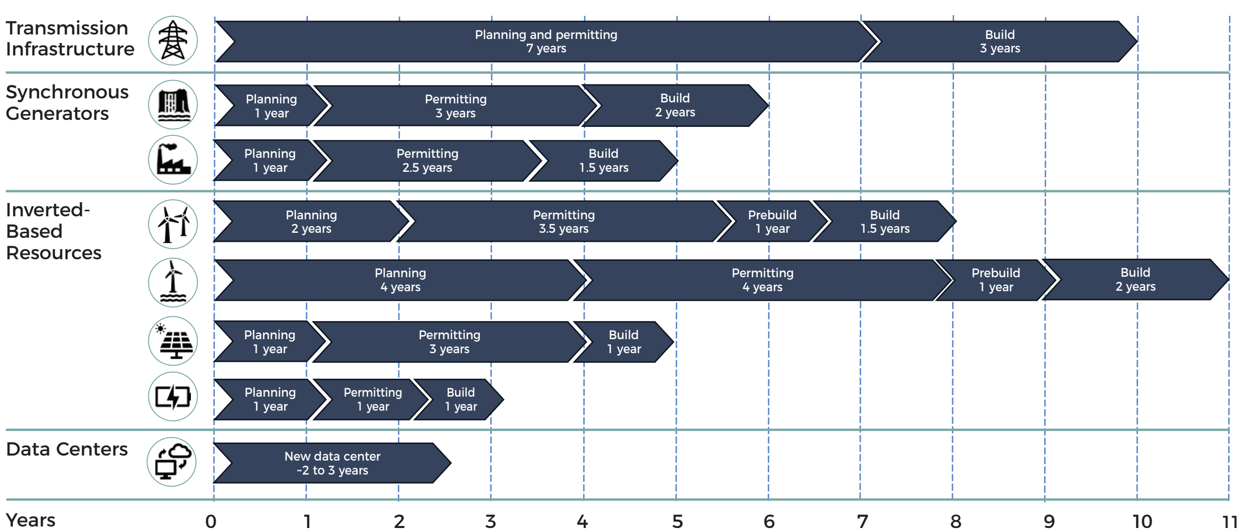


* Demand is measured by power consumption to reflect the number of servers a data center can house. Demand includes megawatts for storage, servers, and networks.

US data center demand is forecast to grow by some 10 percent a year until 2030. SOURCE: McKINSEY & CO.

As demand grows, generation capacity and the infrastructure to transport power must also expand. But upgrading the grid faces major obstacles, especially issues with siting, permitting, and supply chains. While it takes one-and-half to two years to build large load facilities like data centers, new generation plants take three to five years. Electric transmission infrastructure can take up to a decade to plan, permit, and construct. These discrepancies are illustrated in Figure 1.4.

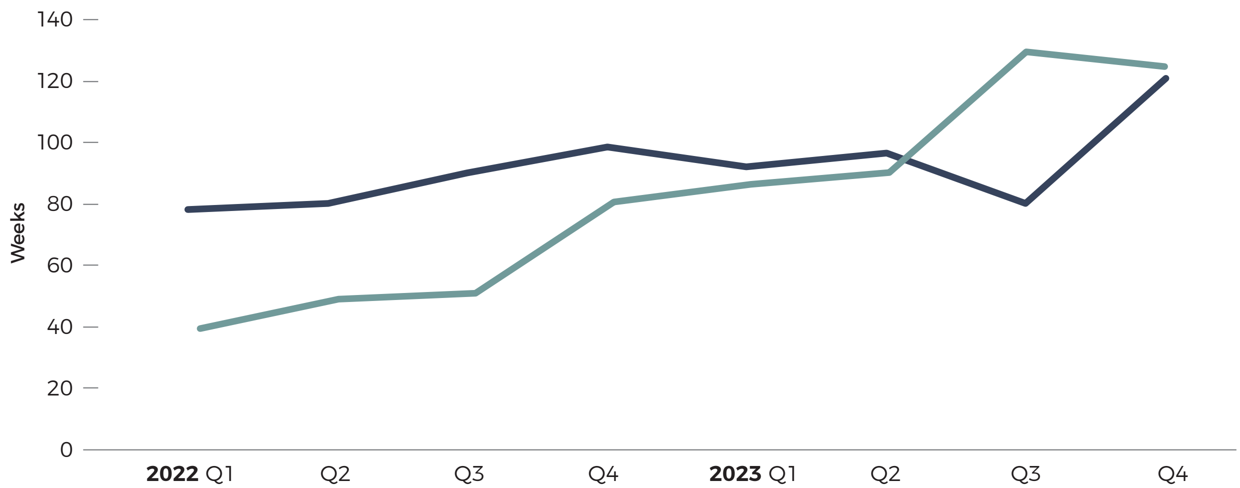
FIGURE 1.4. Illustrative Time to Market for Various Grid Projects



Timelines for grid infrastructure are not aligned with those for large load development, creating bottlenecks for grid supply of electricity. SOURCE: ADAPTED FROM S&P GLOBAL.

Construction timelines are further complicated by the scarcity of core equipment used by entities across the grid, including transmission and large load facilities. For example, nearly 70% of transformers in the U.S. are over 25 years old, and demand is expected to rise significantly by 2030. Prices have already surged by 80%. Lead times for power transformer have increased by 50%, while lead times for generator step up transformers have tripled since 2022 (see Figure 1.5) [6]. Similar supply chain constraints affect other grid equipment such as circuit breakers and switchgear.

FIGURE 1.5. Growth in Large Power Transformer Lead Time



Power transformer lead times have continued to grow, raising growing concerns about a stable and reliable supply chain to enable electricity sector developments. SOURCE: NIAC.

Bulk Power System Connection of Large Loads

The size of large loads connecting to the electric grid can often dictate the connection points—whether distribution, sub-transmission, or transmission voltages levels. This may be defined by the local utilities or may be based on cost-effectiveness. Utilities will have different practices and standards in this area [5]. Some illustrative examples could include (see Figure 1.6, p. 13):

Distribution Connected

- Large loads around less than 5 MW may be connected to typical distribution circuits along with other customers. This may require some upgrades to local distribution equipment (e.g., upgrading transformers, increasing circuit capacity, adding voltage devices, etc.).
- Larger loads in the 5–20 MW range may be served with one or multiple distribution circuits (i.e., "express feeders") extended directly to the site. This may require trenching and conduit to the nearby distribution substation and may also require upgrades to substation equipment such as transformer upgrades and additional circuit bays.

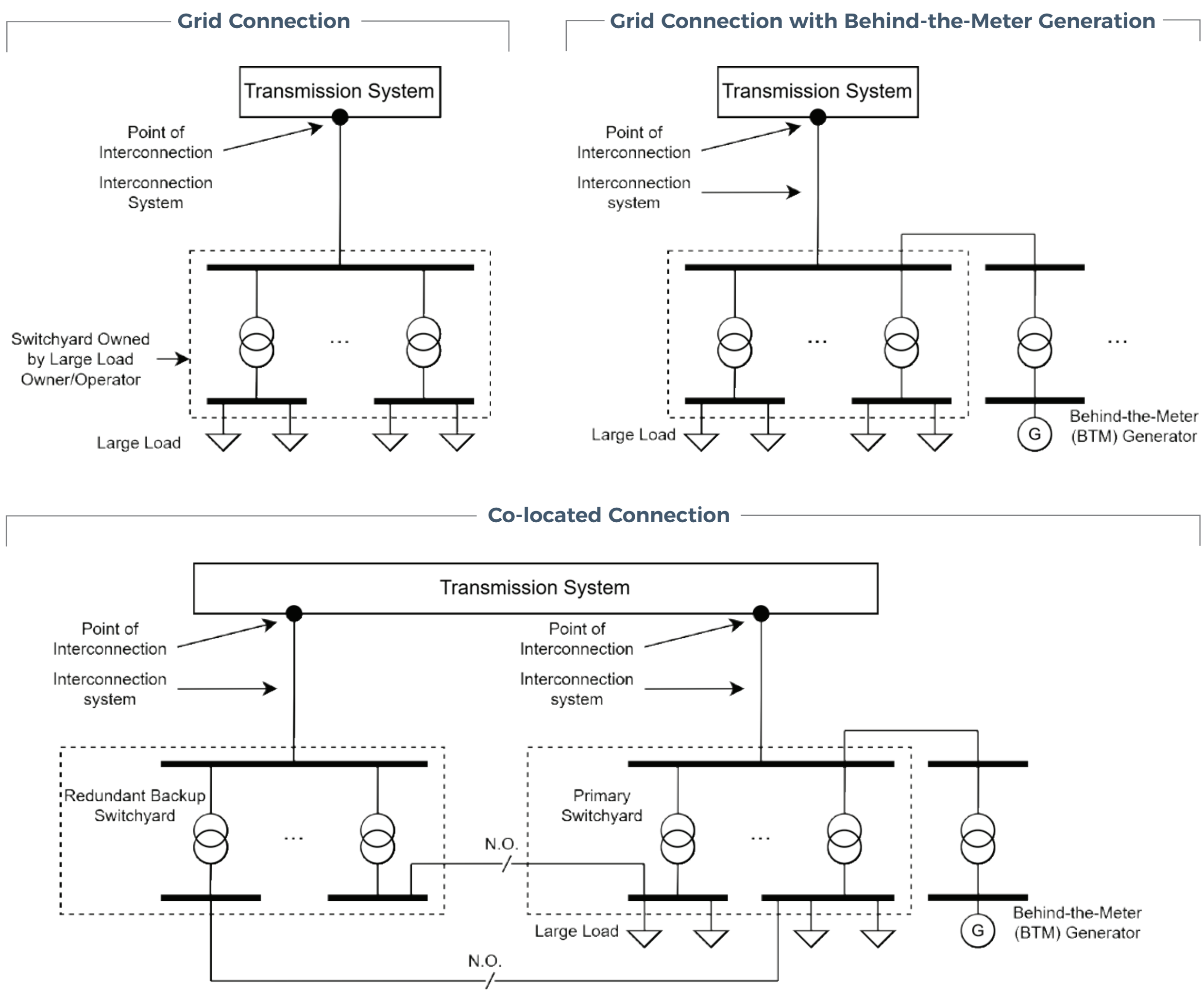
Sub-Transmission Connected

- Larger loads on the order of 20–150 MW may seek connection to the sub-transmission network (e.g., 69 kV), where available, due to the proximity to more urbanized areas fed by these circuits and access to available capacity for larger demand levels. These loads may be served by creating a new substation, transformer, and circuit to the site, as needed.

Transmission Connected

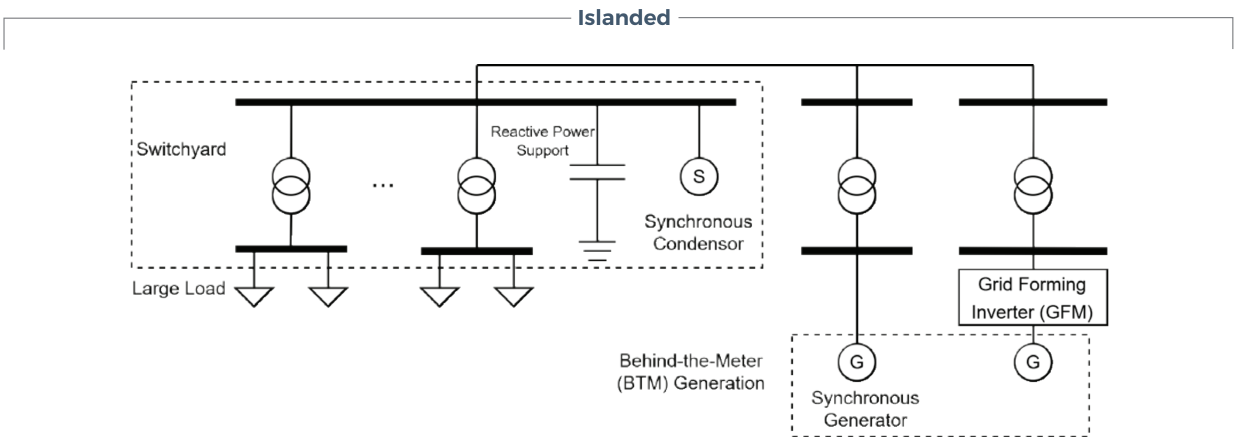
- Large loads on the order of 150+ MW are served by a dedicated substation at higher voltage levels such as 230 kV or 345 kV. So-called “megaloads” of 500 MW and above may require connection to the 500 kV backbone network. Transmission-connected large loads may require dedicated switchyards with utility service brought in to them or other unique configurations/

FIGURE 1.6. **High-Level Illustrative Examples of Grid Connection for Large Loads**



CONTINUED ON PAGE 14

FIGURE 1.6. High-Level Illustrative Examples of Grid Connection for Large Loads (CONTINUED)



Example utility connections for large loads grid connection, grid connection with behind-the-meter (BTM) generation, co-located connection, with BTM generation and redundant backup switchyard, islanded. SOURCE: ELEVATE ENERGY CONSULTING..

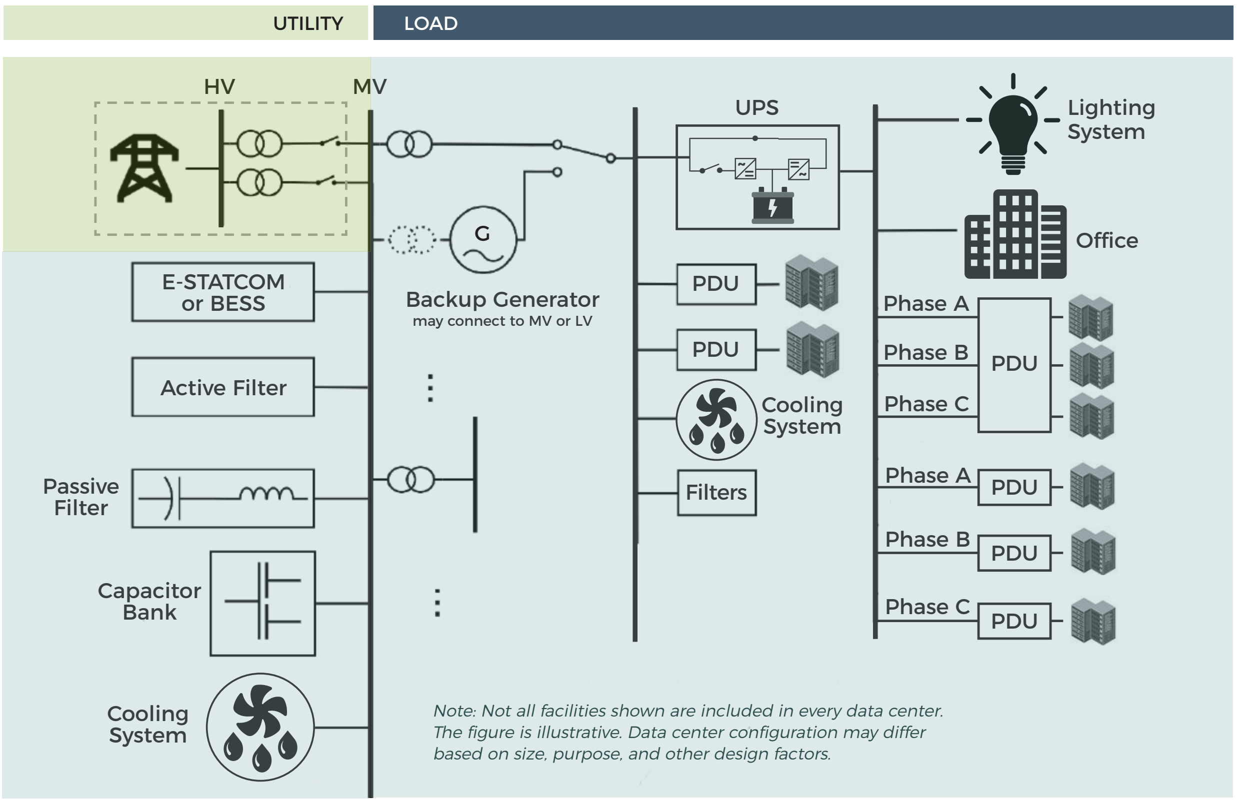
delineations due to their size. Interconnecting systems will typically be redundant or involve a looped network with multiple feeds into a large campus of loads.

As more large loads seek connection at higher voltage levels, it can be assumed that the cost of network upgrades will also increase. This is because the cost of transformers, circuit breakers, switchgears, and other interconnecting network devices increases by voltage class. In addition, larger loads may cause BPS performance violations (thermal overloads, voltage issues, instability conditions, oscillations, or other risks) that must be mitigated to reliably serve these loads.

Example Electrical Layout of a Data Center

While utility service is typically redundant to ensure reliable delivery of power to the customer, electrical infrastructure within the customer fence of a data center is also designed for reliable, continuous power delivery, with built-in redundancy and backup systems to prevent outages. Power typically enters the customer switchyard at high voltage (HV) or medium voltage (MV). The HV/MV bus, switchgear, filters, shunt reactive devices, power factor correction, dynamic reactive power devices, and other auxiliary loads may be tied to this bus. MV to low voltage (LV) transformers step the voltage level down to appropriate levels for distribution within the data center. Large cooling units are typically connected to the LV network to manage IT thermal constraints. The remaining power is distributed through a network of power distribution units (PDUs) or switched-mode power supplies that supply conditioned electricity to individual server racks and IT equipment. This power supply equipment may lie behind uninterruptible power supplies (UPS) that provide temporary backup power in the event of loss of service from the utility and help regulate voltage and frequency stability for the sensitive loads behind them. Figure 1.7 (p. 15) shows an illustrative oneline diagram of the electrical infrastructure of a data center.

FIGURE 1.7. Illustrative One-line Diagram of Data Center Electrical Infrastructure



Example utility connections for large loads grid connection, grid connection with behind-the-meter (BTM) generation, co-located connection, with BTM generation and redundant backup switchyard, islanded. SOURCE: ELEVATE ENERGY CONSULTING.

To further improve uptime and electrical reliability at the facility, data centers may incorporate backup generators, usually powered by diesel, to take over in case of a prolonged grid outage. These generators are automatically engaged through an automatic transfer switch (ATS) when utility power is lost. If present, the UPS devices allow for the servers to maintain power for a short time until the ATS can switch in the backup generation (typically diesel gensets) to continue service. The entire system is monitored and controlled through an energy management system that balances loads, detects faults, and maintains operational efficiency.

Lastly, data centers may also be coupled with co-located generation or battery energy storage systems (BESS), which could be either “behind the meter” or “in front of the meter.” Those resources may participate in wholesale electricity markets or help create a “flexible load” that provides grid services. They may also be used to condition the load in order to shield the external grid from the effects of varying processes (described in the subsequent chapter). This is an evolving aspect of large load interconnections.

2

Grid Reliability Challenges for Data Center Interconnections

While the economic and societal benefits of providing reliable electricity to large load customers are immense, electric utilities are also responsible for ensuring grid reliability at every moment of every day and minimizing risks to serving end-use customers. Establishing a clear baseline understanding of the specific and unique types of grid reliability challenges associated with large loads, particularly data centers, can help industry align with common practices. This chapter aims to educate electricity sector stakeholders about the gravity of the challenges and emphasize the need for swift action.

The Importance of a Reliable Grid

Grid reliability is not just a technical concern—it is the backbone of modern society. A single widespread outage can trigger billions of dollars in economic losses, disrupt critical industries, and erode public trust in utilities and regulators. Hospitals, emergency services, and essential infrastructure rely on uninterrupted power, meaning failures can put lives at risk. In an era of increasing cyber threats and extreme weather, grid instability also poses serious national and local security risks, making communities vulnerable to cascading failures.

Without proactive measures to minimize reliability threats, the consequences could be catastrophic —impacting everything from financial markets to public safety and national defense. Hence, the economic drivers of new large load customers must be delicately balanced with the roles and responsibilities of assuring grid reliability (see Figure 2.1, p. 17).

Challenging Attributes of Data Center Loads

Modern data center loads have unique attributes that can create challenges for conventional grid planning, design, and operations. These challenges include, but are not limited to, the following (see Figure 2.2, p. 18):

- **Size:** Recently proposed data center loads are significantly larger than historical large loads, some by an order of magnitude. And size plays a key role in defining impact to the BPS both individually and in aggregate. As the size of loads increases, technical characteristics which have been in-

FIGURE 2.1. Balancing Act of Economic Drivers of Load Development and Assuring Grid Reliability

ECONOMICS

- Significant long-term, predictable revenue streams for utilities
- Transmission expansion and development
- Enhanced infrastructure utilization
- Potential for demand flexibility
- New service models
- Tax breaks, incentives, and economic development packages
- Local jobs creation

GRID RELIABILITY

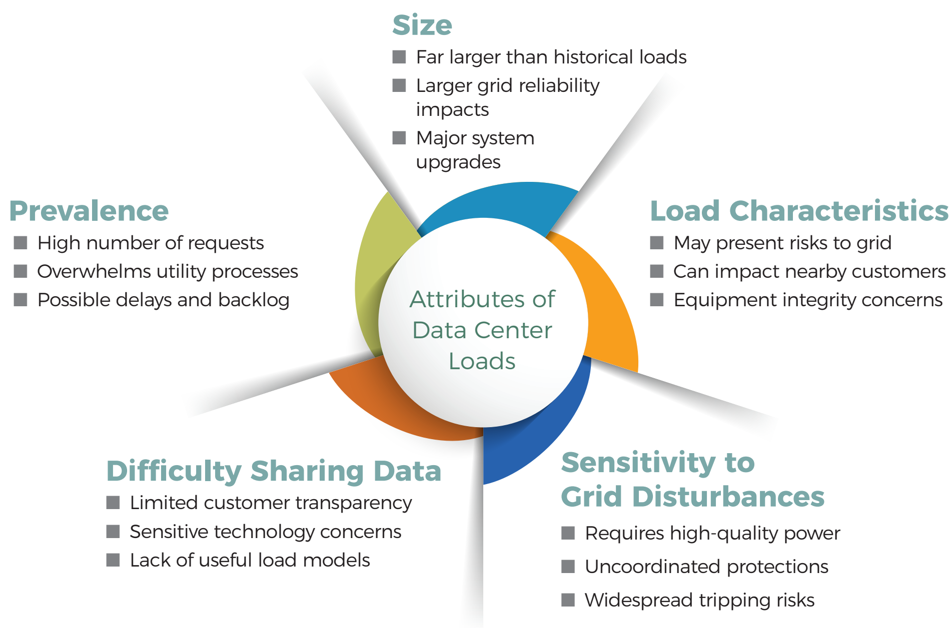
- Overloaded or congested transmission infrastructure
- Voltage and frequency stability issues
- Interconnection backlog inundation
- Regulatory risks and hurdles
- Uncertain operating characteristics
- Reliance on baseload generation to serve loads

Balancing rapid development of large loads such as data centers and grid reliability will be a focal point and notable challenge for the electricity sector in the decades ahead. SOURCE: ELEVATE ENERGY CONSULTING.

significant in the past become very important, and can fundamentally alter the existing ecosystem of generation, transmission, and load. For example, the addition of a very large load in a rural region near existing generation can trigger large high-voltage transmission expansion projects, the need to procure large voltage-supporting devices, and the design of highly complex protection schemes intended to prevent long-term damage to existing generators. Issues like these stem directly from the size of modern large loads and require fundamental reorganization of the existing power system.

- **Prevalence:** Combined with the size of each load and its potential impact on regional grids, the large number of data center requests may easily overwhelm utility interconnection processes and engineering resources. Without (and even with) overhauling existing processes and practices, the aggressive interconnection schedules desired by both customers and utilities are infeasible.
- **Difficulty in Sharing Data:** Data center customers are often unable or unwilling to share the information and data necessary for grid planners and operators to make informed decisions, even with strict confidentiality agreements in place. This is due in part to the sensitive nature of the technology being used, but also to the customer's own data gaps: They may not even know the necessary details about their site's design and performance characteristics.
- **Load Characteristics:** The varying nature of data center loads and of AI data center loads in particular can result in disruption to nearby existing loads, including residential, commercial, and industrial customers. These disruptions can range from mere annoyances (e.g., flickering lights) to severe disturbances that cause the interruption of industrial processes. In the most severe cases, unmitigated variance in output from the loads can cause damage to large substation equipment or permanent damage to BPS generators.
- **Sensitivity to Grid Disturbances:** Data center loads require very high-quality power supply from the grid and are extremely sensitive to variations in this supply. Routine disturbances in the power grid can result in disconnection of the load or take-up of the load by backup systems on site. Sudden

FIGURE 2.2. **Attributes of Data Center Loads**



Data center loads have unique attributes and operational characteristics that create new challenges for grid planners and operators compared with historical large loads. SOURCE: ELEVATE ENERGY CONSULTING

removal of a large load from the grid puts significant strain on the power system and introduces the risk of instability, requiring operators to maintain additional reserves and potentially dispatch generation resources with special flexible characteristics.

Grid Impact and Risks Caused by Data Center Loads

Given the factors above, operational characteristics of data centers could manifest into grid reliability risks if not properly modeled, studied, and mitigated. To be clear, data centers, like all large loads, are not an inherent risk to grid reliability. But failing to adequately plan for and mitigate the impacts of large data centers dramatically increases the potential for problems. So it is imperative that utilities analyze their operational characteristics and potential impacts to the BPS during the interconnection process.

The following subsections describe in more technical detail the operational characteristics of data centers and the types of impact they can have on the power grid.

Load Ramping, Variability, and Uncertainty

The power electronic nature of data centers allows them to ramp very quickly, which can induce swings in power consumption that affect the balance of generation and load. This can have the following effects:

2 This involves the automatic and autonomous response of generator turbine-governor or active power-frequency controls that change active power output for variations in frequency beyond small deadbands.

- **Frequency Control and Balancing Reserves:** Balancing Authorities (BAs) constantly maintain frequency within acceptable limits using the automatic response of generator primary frequency response[2] and secondary controls like automatic generation control (AGC). These measures are not designed to handle large fluctuations in demand. Rather, they are designed for random variability of smaller loads (e.g., residences, businesses, commercial buildings, and even industrial processes) that average out to "noise" on the system. Variability of large loads on the order of 500 to 1,000+ MW have a notable impact on the ability of BAs to maintain tie line flows and frequency within limits, which requires BAs to carry more balancing reserves.
- **Difficulty in Dynamic Voltage Control:** Large variations in load are accompanied by large changes in power flowing through transmission corridors, which in turn causes fluctuating demand for reactive power used to hold voltages within normal levels throughout the system. Just as the existing system is designed to accommodate small random variations in active power but not large variations, it is also generally not designed to accommodate large random variations in reactive power. Depending on the variation of the load, additional large voltage-controlling devices may be required throughout the transmission system to ensure operators are able to control voltage during real-time operations.
- **Synchronous Generation Strain:** Fast ramping of loads may cause frequency variations beyond generator control deadbands[3] which could strain and adversely affect the lifespan of synchronous generator turbines. Inverter-based resources (IBRs) like wind and solar plants may need to provide more frequency control, which could require procuring more fast-acting reserves. Grid operators may need to increase regulation of reserves to manage these spikes.
- **Restoration:** Utilities must manage large ramps during system restoration following severe outages or emergency conditions. Establishing ramp rate limits on large loads could help smooth system operations.

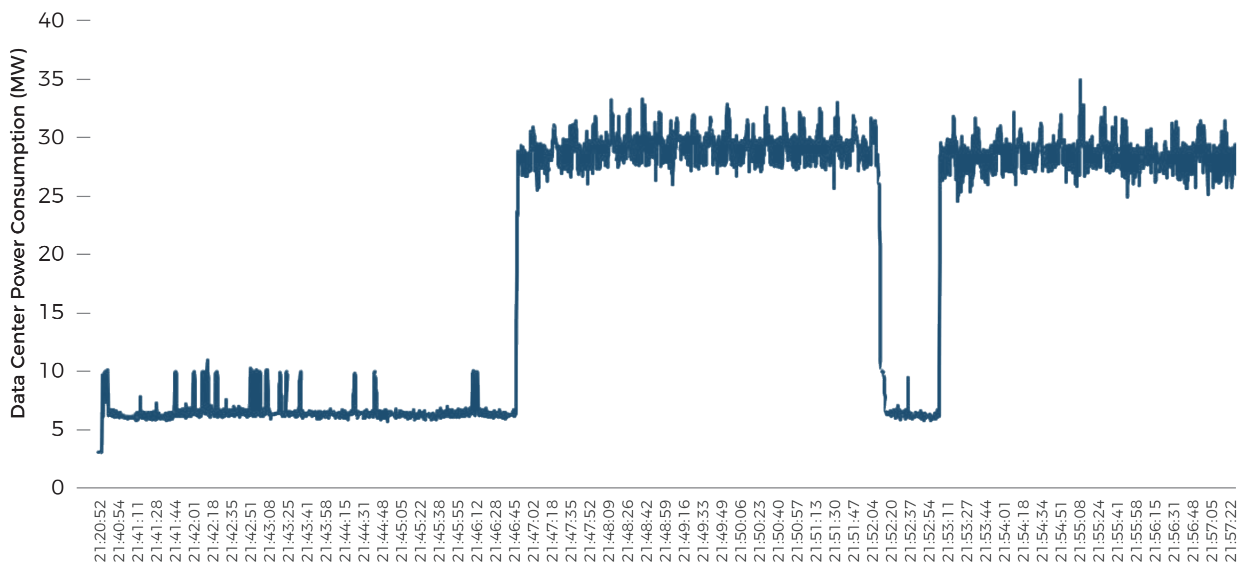
Note that not all data centers exhibit significant ramping, variability, and uncertainty; some may be relatively constant loads with high load factor (i.e., rarely offline). This depends on the digital services provided by the data center and on the design of the facility. However, even in designs with high load factor and low variability, the sheer size of these loads can present problems during more infrequent events such as when the site comes offline or back online, requiring mitigations discussed above.

Load Cycling and Oscillation Risks

Related to their capacity for short-term load ramping, data centers may cycle through multiple periods of higher and lower demand over time. AI workloads such as deep learning training and inference involve significant yet intermittent computational power. Graphics processing units (GPUs) and accelerator-based workloads often process data in batches, causing rapid swings in power consumption as different job phases execute. AI models leverage parallelized computations across

3 Deadbands are small margins around nominal 60 Hz frequency to avoid constant action of controls, which is particularly important for wear and tear on electromechanical systems.

FIGURE 2.3. AI Training Power Consumption Example



New and challenging load consumption patterns have been observed particularly for AI data centers, which can pose potential grid stability and reliability risks and thus must be effectively modeled, studied, and mitigated.. SOURCE: EDGETUNEPOWER, INC.

thousands of GPUs, tensor processing units (TPU), and central processing units (CPU).[4] These units often synchronize at certain steps, leading to periodic spikes and dips in power demand. Large-scale AI training involves massive and possibly cyclical or quasi-periodic surges in computational power demands. These effects may multiply if they are synchronized across data center locations.

Observations of power consumption of data center load have shown how unconventional they are compared with historical end-use loads, with activity like AI training runs leading to extremely intermittent power consumption. Figure 2.3 shows an example of a 50 MW data center block (the entire facility has four points of connection totaling 200 MW). Active power consumption captured with a microprocessor-based relay high speed data recorder shows power consumption jump from 6 MW to 30 MW in a matter of 290 ms (about one-quarter of a second). Power consumption is then highly variable for about 5 mins, with numerous 5+ MW spikes. Then it drops briefly to low power consumption levels before returning to high power consumption. Note that this facility is not interfaced with the grid though a UPS, so the power consumption is observed directly on the grid side of the customer interface.

These fluctuations could present risks to the interconnected BPS and its natural modes of oscillation (with frequency and oscillatory characteristics that affect the entire system).[5] If demand from data centers (particularly AI data centers) exhibit oscillatory behavior at frequencies in the range of natural power system modes (typically 0.1–0.4 Hz or so), the system could experience poorly damped oscillations on a wide scale that could lead to system instability. For example, an event

4 Data centers may use a combination of these types of processing units to optimize performance and efficiency.

5 Similar in nature to the infamous Tacoma Narrows Bridge collapse in 1940 where wind-induced oscillations at or near the resonant frequency of the bridge cause amplifying movements until it eventually catastrophically collapsed.

in 2019 involving a malfunction at a synchronous generator site in Florida caused amplified power oscillations across the entire Eastern Interconnection up to Minnesota and into New England [6].

Load Ride-Through Performance

Inadvertent disconnection of large end-use loads, particularly when aggregated across multiple locations, can pose a serious threat to grid reliability. Data centers may be prone to disconnection during grid events if not coordinated with utility protection system designs (e.g., fault duration, number of reclosing attempts). This is due to the sensitivity of power electronic server loads, strict requirements of digital uptime, and the availability of on-site backup generation. Yet faults and other grid events are inevitable, and they occur daily due to a variety of natural and manmade causes. As mentioned earlier, a large data center disconnection event in Northern Virginia in 2024 raised serious concerns among utilities and regulators. These types of behaviors are not adequately modeled today or included in grid reliability studies, given current industry practices, which could create blind spots for grid operators that could exacerbate emergency operating conditions during grid events.

Data Center Load Dynamic Performance

The dynamic performance of end-use loads depends on the composition and control systems of the facility and can significantly influence local and regional grid stability, particularly for large-scale installations. Data center loads typically consist of power electronic equipment, cooling systems, and supporting power infrastructure. The power electronics include servers, storage systems, and networking equipment that handle digital data processing. Cooling systems manage the substantial heat produced by this equipment and may include computer room air conditioners and handlers, liquid cooling systems for high-density AI workloads, and water-based pumps and fans. The power infrastructure includes UPS systems, power distribution units (PDUs),[6] power converters, backup systems, BESS, generators, and other electrical equipment. Most of the end-use loads are interfaced with the grid through UPS systems, which significantly influence the facility's electrical behavior. Collectively, these components determine the facility's dynamic response and can impact grid stability depending on the facility's size and integration characteristics.

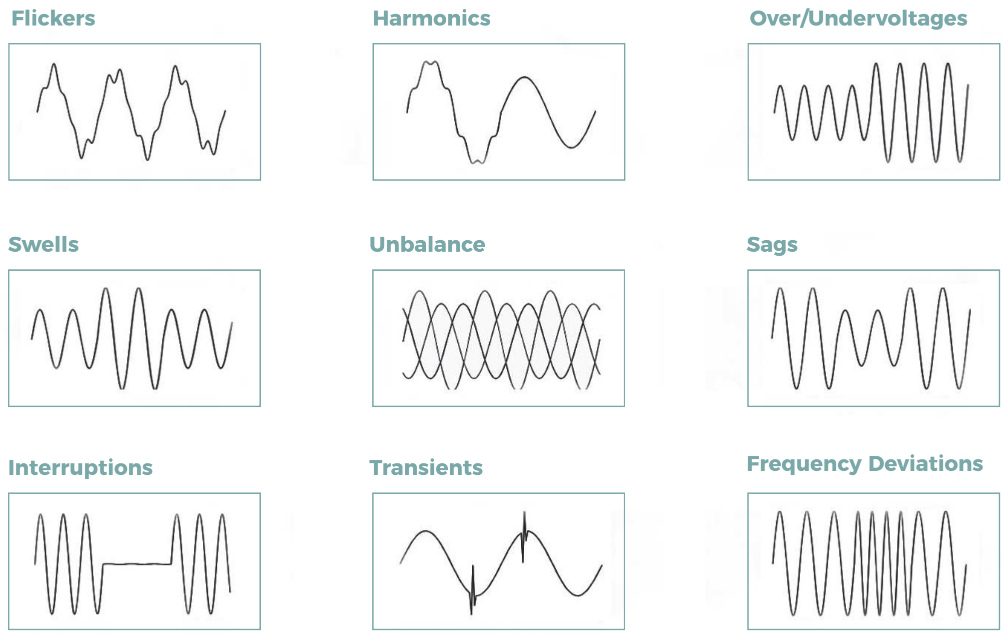
Power Quality and Harmonic Emissions Concerns

All power system components may introduce potential power quality issues that must be studied, monitored, and addressed. These issues can range from voltage sags and swells to harmonics, frequency variations, flicker, transient surges, power factor correction, electromagnetic compatibility, and more. Utilities normally evaluate and mitigate these concerns using a suite of measurement devices and specialized studies. Some of these studies require significant amounts of carefully specified data to correctly analyze and mitigate concerns.

Harmonic emissions from data centers stem primarily from the nonlinear nature of components at the site. UPS systems, switched mode power supplies, and variable frequency drive (VFD)-driven cooling loads are often the main culprits, because of the rectifiers they use for power conversion.

6 PDUs convert higher voltage power to voltages suitable for power electronic IT equipment (e.g., 480V or 208V).

FIGURE 2.4. **Types of Power Quality Issues**



SOURCE: ELEVATE ENERGY CONSULTING. ADAPTED FROM FS, INC. (WWW.FS.COM).

Utilities have applied stringent power quality requirements (e.g., IEEE 519) to large loads for many years [7]. Customers may need to install harmonic filters, higher performance equipment with lower harmonic distortion, and power factor corrections to meet these requirements and mitigate problems.

Subsynchronous Oscillation Risks

Subsynchronous oscillations (SSO) are a family of oscillation phenomena that have been studied for many decades. These oscillations have multiple contributing factors including series resonances in the external grid, resonant mechanical modes in synchronous generator shaft systems, and damping characteristics of power electronic converters. There are several types of SSO that are of concern with data center loads, including:

- The load cycling and oscillatory behavior driven by digital processing described previously. If the fluctuations are large enough and their frequency overlaps with critical generator shaft mode frequencies for nearby generators, the generators can be permanently damaged.
- Subsynchronous torsional interaction (SSTI) where load rectifier controls are negatively damped at frequencies overlapping with generator torsional frequencies.
- Subsynchronous control interactions (SSCI), which are similar to SSTI except that the instability results from overall negative system damping overlapping resonance points in the network due to series compensated transmission lines. This is of large concern for IBR generation systems, but the extent of the risk for data center controls will depend on the specific nature of the load.

All forms of SSO require highly detailed data and sophisticated modeling to analyze and mitigate. Components of load which interface with the system via power electronics are of particular interest, but the relevant details of these elements are not easily available to date. In regions where synchronous machines are present, a significant amount of detailed design data is required from the machine manufacturers, and this data is often difficult to obtain.

As data center interconnections grow in both size and number, the need for conducting these studies—particularly in areas with synchronous generators and series-compensated lines—may grow as well. Utilities and customers can resolve issues with SSO with careful tuning, damping devices, filters, special protection schemes, energy storage, and other mechanisms.

Protection System Impacts

Data centers are unlikely to contribute significant amounts of fault current to the system, primarily because most of the facility load is electronic. The IT equipment is almost entirely power electronic, and the cooling loads are driven by VFDs that decouple the motor from the grid, have current-limiting features, and/or reduce output during faults.

Nonetheless, rapid load variability, harmonics, and grid-paralleled on-site generation could cause issues with utility protection systems. So utilities must study how connecting a new large load would affect these protection systems, especially with any grid-paralleled onsite generation and any fault current that could be contributed by the large load facility. Protection studies will show whether utilities can properly detect and clear faults within their standards, as well as whether they need to modify an existing protection system to align with features of the large load facility. The impact and cost of these modifications may vary depending on the type of protection system (distance relaying, current differential, communication-assisted schemes, etc.).

3

Challenges With the Large Load Interconnection Process

Utilities may find themselves torn between the economic opportunity of quickly connecting large loads and the obligation to thoroughly assess the impact those loads will have on the reliability and cost of electricity across the grid. As the size and breadth of large load interconnections grows, and the economic pressure of quickly connecting these loads to the system rises, it becomes critically important for customers and utilities to conduct the engineering studies, assessments, and analyses necessary to maintain reliable operation of the grid.

Currently, a lack of standardized interconnection processes for large loads may be weakening the ability of the utility to effectively meet those obligations. This chapter summarizes some of the limitations of historical large load interconnection processes, possible areas of opportunity and improvement, and how utilities can improve interconnection processes to better assess potential grid reliability risks.

Issues with Rate Design and Customer Equity

Regulated electric utilities are responsible for delivering reliable, secure, and safe electricity to customers in a just and affordable manner. State utility regulatory agencies approve retail electricity rates and tariffs to ensure utilities can meet electricity demand, maintain affordability, support economic development by attracting new loads, and align with state energy policies. In the context of large load interconnections, several areas of rate design warrant particular attention [8]:

- **Cost allocation** for network upgrades associated with large load interconnections, and the possibility of shifting costs onto existing ratepayers.
- **Minimizing stranded asset risk** from underutilized transmission or generation infrastructure if forecasted demand levels fail to materialize.
- **Resource adequacy and energy assurance** challenges stemming from challenges building new generation and transmission fast enough to meet these demands.
- **Grid reliability risks** associated with the volatile and uncertain characteristics of newer large loads such as rapid voltage and frequency fluctuations or impacts on power quality.

- **Deployment of emerging technologies** including grid enhancing technologies (GETs), small modular reactors, and long-duration energy storage, while managing financial and societal risks.
- **Balancing state policy objectives** such as decarbonization and economic development with grid reliability limitations amid rapid changes in generation mix and consumption behaviors.

Tariff designs must clearly define eligibility based on customer demand characteristics, establish contract terms that provide sufficient certainty for utility infrastructure investments, and implement rate structures that reflect the true cost of service while incentivizing reliable and beneficial consumption behaviors.

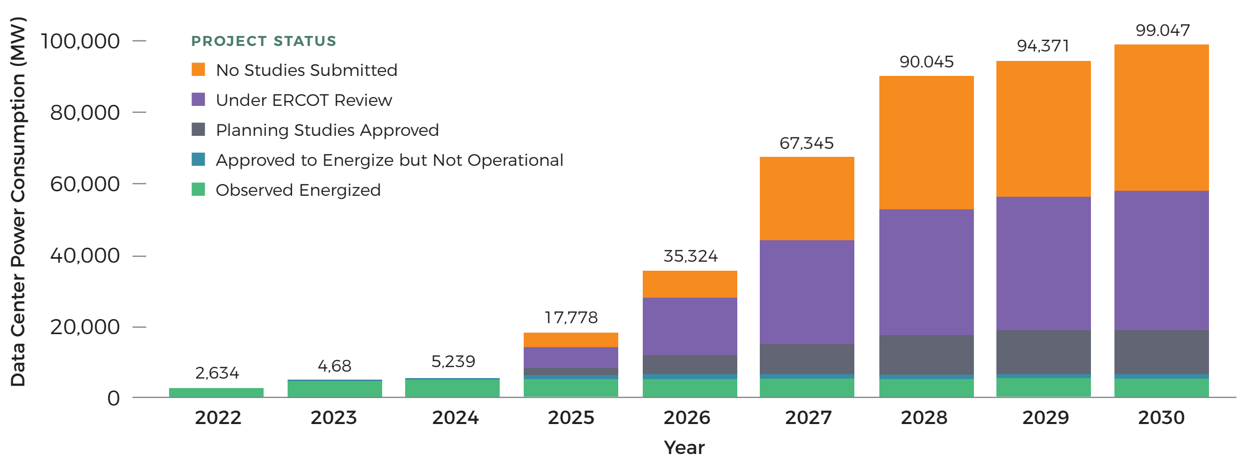
In this environment, utilities and system operators have to wonder: "Which large load applications are real?" Introducing a standardized and transparent load-side interconnection process can help minimize speculative load application behavior and provide clarity for both utilities and developers

Problems with Speculative Interconnection Requests

The electricity sector is experiencing a surge in speculative interconnection requests for data centers, stemming from a fragmented and opaque load interconnection process. Currently, there is often no formal or transparent load interconnection queue, and the barriers to entry in terms of time, technicality, and financial commitment are quite low. This environment encourages developers to submit multiple requests for potential projects, seeking out least-cost connection locations and leading to inflated demand projections and inefficiencies.

For example, Figure 3.1 shows how the ERCOT large load interconnection queue balloons from 2025 to 2030. Most projects in this queue have no studies submitted to ERCOT or currently under review, and only a small fraction have completed studies approved or approval to energize.

FIGURE 3.1. **ERCOT Large Load Interconnection Queue**



The large load interconnection queue has ballooned in ERCOT and is expected to continue; however, many of the proposed interconnection applications have not had reliability studies submitted or those studies are under ERCOT review. SOURCE: ERCOT.

In this environment, utilities and system operators have to wonder: “Which large load applications are real?” Introducing a standardized and transparent load-side interconnection process can help minimize speculative load application behavior and provide clarity for both utilities and developers [9], [10].

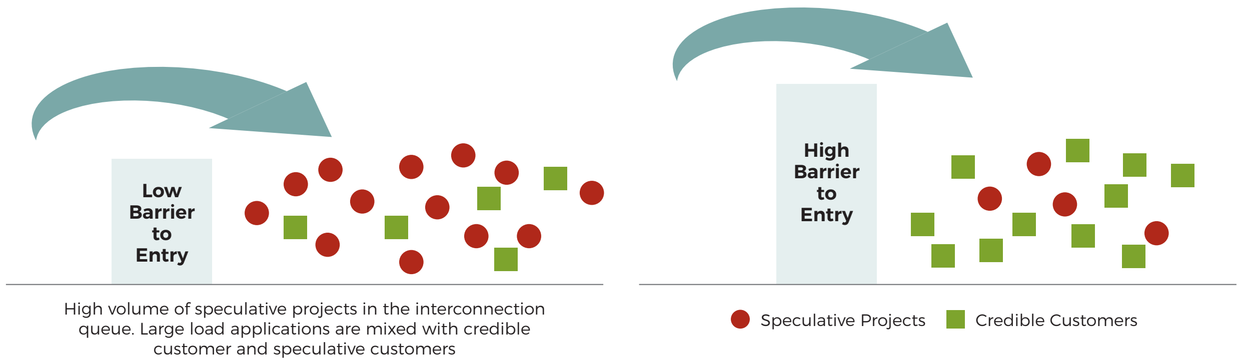
Little to No Barrier to Entry

The prevalence of speculative load interconnection applications makes it increasingly difficult to distinguish credible customers from those submitting speculative requests. This issue arises due to a combination of factors that reduce the barriers to entry for prospective applicants, effectively allowing them to engage with the utility without significant consequences. In many cases, large load interconnection applicants face minimal or no financial commitments, lack site control, have limited financial credibility, submit redundant or duplicative applications, or are technologically unprepared. Some regions even allow applicants to enter the queue with little to no “readiness” indicators—a simple phone call or email may be enough to initiate the utility’s analysis. Refundable application fees, low or no study costs, and the absence of strict site control requirements further lower the threshold for participation.

While such ease of access may have worked when most applicants were established commercial and industrial customers, today’s landscape is different. Growing demand from multiple industries has led to a surge in speculative applications, with many entities seeking to secure a queue position “just in case.” Without stronger readiness requirements, these speculative projects can overwhelm the interconnection process, delaying legitimate projects and creating inefficiencies across the system. Figure 3.2 illustrates how a low barrier to entry results in a high volume of applications dominated by speculative projects, leading to significant downstream consequences.

FIGURE 3.2. Illustration of Speculative Interconnection Projects with a Low Barrier to Entry

THE BARRIERS: Financial Commitments; Site Control; Financial Credibility; Unique Applications; Technical Requirements Met



Raising the barrier to entry for new large load interconnection requests can help weed out more of the speculative requests, leaving more certainty and likelihood of interconnection success. SOURCE: ELEVATE ENERGY CONSULTING.

An Opaque Large Load Interconnection Process

In most cases, the large load interconnection process is bespoke and varies across utilities and jurisdictions. Large load policies and procedures are subject to a broad and changing set of stakeholders, which prevents standardized application requirements, study assumptions, and cost allocation.

This opaque load interconnection process creates significant challenges for both utilities and large load customers. Applicants struggle to understand interconnection timelines, costs, and technical requirements—another reason many applications may be speculative in nature. Utilities must process redundant or unviable requests, diverting resources from legitimate projects and slowing down the queue. Additionally, uncertainty around available capacity and project feasibility can lead to misinformed investment decisions, increasing financial risk for developers and utilities alike.

Without a clear and structured interconnection framework, utilities risk bottlenecking grid expansion efforts, delaying critical infrastructure, and ultimately hindering economic growth

The absence of a formal, transparent queue exacerbates these issues, as moving up or down the list of loads being studied can seem arbitrary or be influenced by factors like a project's economic development priority for the utility or state. This unpredictability discourages collaboration, erodes stakeholder trust, and may lead to disputes or regulatory intervention. Furthermore, a non-transparent process makes it difficult for policymakers and regulators to assess system constraints and plan for future infrastructure needs. Without a clear and structured interconnection framework, utilities risk bottlenecking grid expansion efforts, delaying critical infrastructure, and ultimately hindering economic growth [10].

PHOTO: ISTOCKPHOTO/GERVILLE

Minimal or Nonexistent Technical Requirements for Large Loads

Traditional load interconnection processes have been built around a "load-serving" philosophy, where utilities are expected to meet customer demand without imposing stringent technical requirements. As a result, large load customers are rarely required to provide detailed performance specifications before interconnection.

To properly assess and mitigate potential reliability risks, utilities need critical data, including ride-through capabilities, power quality characteristics, load composition, time-varying behavior, and comprehensive system models. Without this information, utilities face major blind spots in planning and reliability assessments.

The absence of standardized technical requirements has far-reaching consequences. Utilities must dedicate significant time and resources to identifying and obtaining missing data from applicants. Without clear performance standards, latent reliability risks can arise, potentially requiring costly network upgrades that may be passed on to existing ratepayers. At worst, inadequate interconnection practices could result in voltage instability, equipment damage, or even safety hazards for utility personnel and the public. Establishing structured technical requirements is essential to ensuring grid reliability and mitigating these risks.

Inadequate Large Load Interconnection Studies

The NERC FAC-002-4 Reliability Standard establishes requirements for each Transmission Planner and each Planning Coordinator to study the reliability impacts of interconnecting new electricity end-user facilities. These studies assess the reliability impact of the new interconnection on affected systems; assure the end user's adherence to the NERC Reliability Standards, TO planning criteria, and facility interconnection requirements; and must include steady-state, short-circuit, and dynamics studies, as necessary.

Although the NERC standard requires studies, there are no established standard industry practices in this area, leaving utilities to set them on a case-by-case basis. While some utility judgment is typically acceptable, too much leeway can lead to biases and disparities between specific projects or customers, and unclear and potentially unjust interconnection processes for customers. Case-by-case judgment is also prone to error, because individual engineers are tasked with filtering industry data and creating their own practices rather than relying on a consensus of informed industry experts. Further, lack of standardized studies can also lead to missed reliability risks before interconnection and potential grid instability, damage to electrical equipment, and public safety risks down the line. These systemic risks and the need for standards to address them are precisely why the energy sector has reliability organizations like NERC.

Lastly, because of the low barrier to entry and high volume of speculative interconnection requests, utilities may be too overwhelmed to conduct detailed studies for all applications. Moving toward a cluster study-based approach, similar to the generator interconnection queue reforms, could alleviate the serial challenges in the interconnection queue [11].

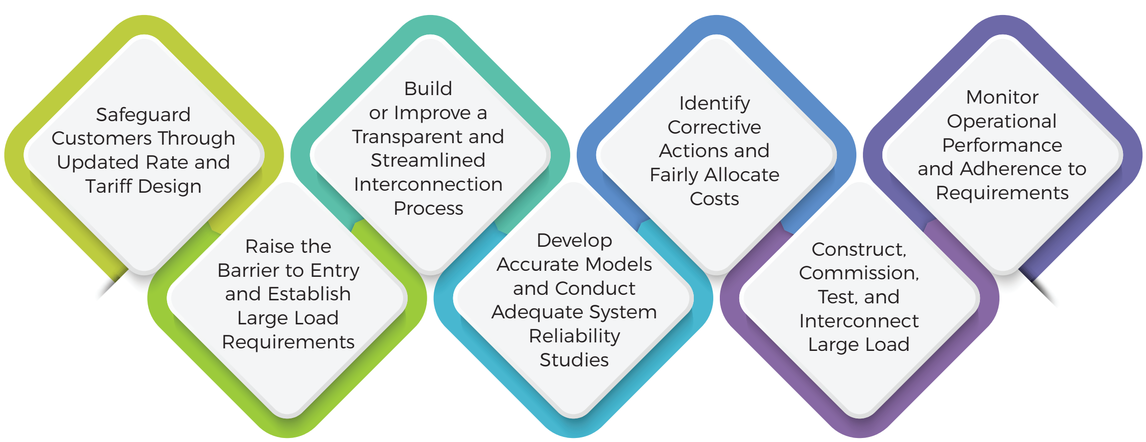
4

Process Improvements for Large Load Interconnections

The rapid growth of large loads seeking connection to the BPS—mostly driven by data centers and AI loads—is reshaping utility interconnection processes. While large load customers bring economic opportunity, they also introduce significant planning, operational, and financial challenges that utilities must navigate. If not carefully managed, large loads can strain grid reliability, create cost shifts that unfairly burden existing ratepayers, and disrupt long-term system planning.

To balance these risks with the potential benefits, utilities must modernize their approach to large load integration—ensuring fair cost allocation, clear interconnection requirements, and robust reliability protections. By proactively addressing these challenges, utilities can safeguard system stability, create a more predictable and efficient interconnection process, and foster a regulatory environment that supports both customer growth and grid resilience. This chapter covers some of the areas for large load interconnection improvement, as illustrated in Figure 4.1.

FIGURE 4.1. Key Components to Large Load Interconnection Process Improvements



While different transmission providers may have varying large load interconnection processes, there are some rather consistent key components of an effective process described in this report. SOURCE: ELEVATE ENERGY CONSULTING.

BOX 2

Safeguard Existing Customers during Large Load Growth

To protect existing ratepayers during such volatile conditions, utilities and regulators can consider implementing safeguards when designing tariffs for large load customers. These may include [12], [8]:

FINANCIAL SAFEGUARDS

Customer-Paid Interconnection and Grid Upgrade Costs: Large load customers should pay the full cost of transmission and distribution system upgrades associated with the direct connection of the load to the utility system.

Fair Allocation of Network Upgrade Costs: Large load customers should pay an equitable portion of any broader system network upgrades needed to reliably connect the large load (e.g., new transmission infrastructure to address overloads). The cost allocation methodology should be carefully reviewed to protect existing ratepayers from subsidizing infrastructure upgrades that benefit a subset of customers.

Financial Guarantees and Collateral Requirements: Utilities can require high security deposits or collateral to prevent applicants from defaulting and protect ratepayers from stranded costs.

Contractual Commitments and Exit Penalties: Utilities can require long-term contracts (e.g., 15-20 years) for large load customers with notable and enforceable exit penalties to help ensure utilities can recover infrastructure investment costs and avoid stranded assets.

DEMAND CHARGE SAFEGUARDS

Minimum Demand Charges: Utilities can require large load customers to contribute to fixed costs (i.e., fixed level of demand), even during periods of usage below this level.

Demand Ratchets: Utilities can bill demand on a percentage of the highest recorded demand over a specified period, ensuring stable cost recovery (e.g., 50-80% demand ratchet based on the highest demand in the past 3 to 6 months).

Minimum Load Factor Requirements: Large load customers must maintain a baseline level of demand or load factor to help avoid network underutilization and associated costs.

GRID RELIABILITY AND OPERATIONAL SAFEGUARDS

Resource Adequacy Contributions: Large load customers may be required to provide some degree of resource adequacy contributions or be subject to higher demand charges or capacity fees. Some customers may be able to lower rates or receive credits, such as those who participate in demand response, have self-generation or storage capabilities, or can reduce demand during peak operating conditions.

Demand Response and Curtailment Options: Utilities can require large load customers to reduce net consumption during peak periods or grid emergencies (e.g., through curtailing demand or on-site generation).

ENVIRONMENTAL AND SUSTAINABILITY REQUIREMENTS

Renewable Energy Procurement: Large load customers may be required by state policies to purchase new electricity from clean energy resources rather than contractually consume energy from existing zero-carbon resources intended for existing customers.

The safeguards described in Box 2 (p. 30) are intended to balance the economic benefits of large load customers with the need to protect existing ratepayers from financial risks and to support the utility in terms of operational reliability obligations. Regulators and utilities must carefully structure tariffs to ensure large customers contribute fairly to system costs while maintaining grid reliability and affordability.

ADDITIONAL CONSIDERATIONS AND SAFEGUARDS

Table 4.1 outlines some additional non-market considerations and safeguards that utilities could consider to ensure fairness, prevent cost shifting to existing ratepayers, and maintain grid reliability when large load customers make financial arrangements outside traditional utility tariffs.

TABLE 4.1. Additional Considerations and Safeguards for Large Loads

Topic	Consideration	Safeguard
Power Purchase Agreements (PPAs)	Some large-load customers enter PPAs that allow them to procure power directly from generators at wholesale prices while still relying on the grid for backup power or peak needs.	Regulators should ensure that customers with PPAs contribute appropriately to transmission and reliability costs if they intermittently use power outside their established PPA. Ensure standby service rates and grid access fees reflect the true cost of reliability support for large loads that rely on the transmission system.
Market Participation Risks	If large loads have access to behind-the-meter generation, they may manipulate market pricing to their advantage.	Regulators should monitor market manipulation (e.g., demand reduction in exchange for market payments) and ensure compliance with grid reliability obligations.
Economic Development Riders (EDRs)	Large loads consume vast amounts of energy, increasing utility and local tax revenues yet provide mixed levels of employment opportunities or other benefits and may foreclose the possibility of service other loads.	Tie rider benefits to clear and measurable contributions beyond energy consumption and revenues such as investments back into the community, local hiring, or grid support services.
Contract Transparency and Regulatory Oversight	Private PPAs, bilateral contracts, and EDRs often occur outside traditional utility ratemaking processes, limiting transparency.	Regulators should require disclosure and approval of key contract terms and revisions thereof.

SOURCE: ELEVATE ENERGY CONSULTING.

EMERGING CONSIDERATIONS FOR RATEPAYER SAFEGUARDS

Load-serving entities, regulatory commissions, grid operators, and other stakeholders must consider how adding new large loads can affect rates and service for other ratepayers. For example:

- Can existing resources be used to reliably serve these loads?
  - If existing resources (e.g., merchant generators or renewable projects under virtual PPAs)[7] are brought under a load serving entity's control for the purpose of serving large loads, what are the resource adequacy impacts of doing so?

7 A virtual PPA (VPPA) contract is typically between a new renewable generator and a new large load. The new large load does not own and is not responsible for the physical electrons generated by the generator. Instead, the VPPA allows the new large load to acquire RECs while continuing to consume energy from its utility [39].

- What impacts will large loads have on fuel, congestion, and ancillary services costs?
  - Oftentimes these charges are passed through in rates via fuel adjustment clauses that are allocated to all retail customers. Should that allocation change with large loads?
  - How should those costs be assigned if they are not explicitly priced (e.g., as in an organized energy market)?

Raise the Barrier to Entry and Establish Interconnection Requirements

Utilities can limit the interconnection queue to creditable customers with viable projects by bolstering application requirements with measures such as:

- **Higher Financial Commitments:**
  - Significantly higher non-refundable application fees and deposits, sometimes based on $/MW demand capacity.
  - Higher study fees to allow utilities to hire adequate staff to perform increasingly complex studies.
  - Milestone-based payment schedules.
  - Pre-payment for network upgrades.
  - Long-term electric service contracts.
  - Higher minimum demand charges of their contract capacity.
  - Withdrawal penalties.
- **Site Control:**
  - Signed purchase agreement, long-term lease, or option contract (with substantial commitment) with property owner(s).
  - Proof of zoning compatibility.
  - Conditional use permits, in some cases.
  - Local governmental approval or conditional approval.
  - Air quality, water use, stormwater, and wetland permits.
- **Financial Credibility:**
  - Demonstration of customer financial strength, such as credit rating.
  - Audited financial statements.
- **Avoiding Duplicative Requests:**
  - Agreements between third-party developers and end-use customers.
  - Contract, letter of intent, or binding agreement between developers and end-use customers.
  - Disallowing multiple interconnection requests from a single entity (or parent entity) for the same site or project, unless there is a technically justified need.
  - Restrictions on queue position transfer.

- **Technical Requirements (see Chapter 5 for more details)**
  - Site plans and electric designs such as oneline diagrams, transformer and substation specifications, and protection and control designs.
  - Settings and equipment capabilities for UPS, on-site generation, and other devices.
  - Detailed expectations for system performance and power system-facing behavior and dynamic characteristics, which may include modeling in some cases.
  - Equipment procurement timelines or proof of orders.
  - Signed agreements with engineering, procurement, and construction contractors.

Measures like these can help utilities reduce backlogs in the queue and avoid wasting resources on nonviable applications. For further help, Appendix A of this report provides a list of questions that utilities can ask during the interconnection process and information they should expect large load applicants to provide.

To be effective, these measures need to be enforced. For example, applicants who fail to meet the technical requirements, site control, payment schedules, or other milestones should risk losing their queue position or being removed from the queue entirely. This can help shift utility resources and attention to more serious, committed customers.

Build or Improve a Transparent and Streamlined Load Interconnection Process

A well-defined and transparent interconnection process is essential to ensuring that all large load customers are treated fairly while maintaining grid reliability and efficiency. Establishing clear procedures not only improves consistency for how requests are handled but also expedites processing, reducing uncertainty for both utilities and customers.

A well-defined and transparent interconnection process is essential to ensuring that all large load customers are treated fairly while maintaining grid reliability and efficiency. Establishing clear procedures not only improves consistency for how requests are handled but also expedites processing, reducing uncertainty for both utilities and customers.

Currently, utility approaches to large load interconnection vary widely. Some utilities lack a formal process altogether, addressing large load requests on an ad hoc basis, which can lead to inconsistent decision-making and delays [13]. Others have queue-based processes, but a lack of transparency leaves customers uncertain about their position in the queue or expected timelines. Implementing established milestones and clear timelines—covering application processing, system impact studies, upgrade determinations, and interconnection agreements—creates predictability for all stakeholders and fosters a more effective planning environment.

As mentioned above, one key improvement is the adoption of a cluster study approach, similar to the generator interconnection process reforms seen in Federal Energy Regulatory Commission

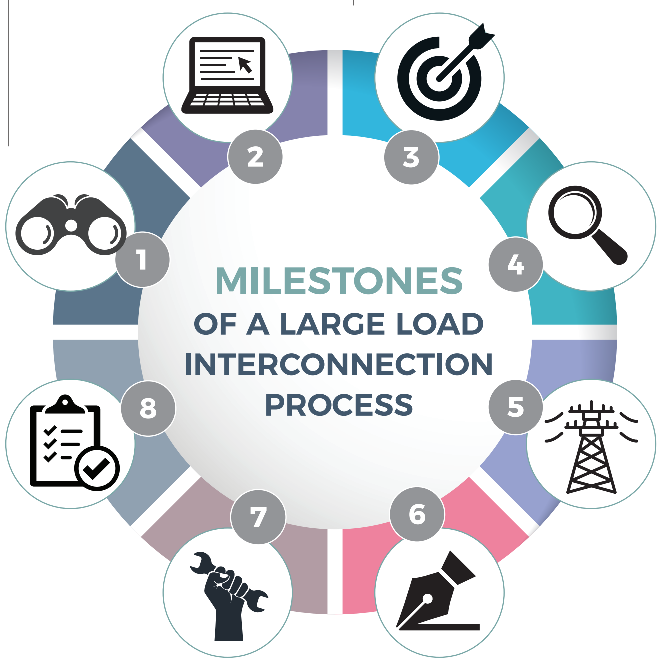
FIGURE 4.2. Milestones of a Large Load Interconnection Process

MILESTONE 1
Pre-Application Phase
Large load customers engage with utilities early in the process to discuss their tentative plans for load interconnection, including project details, siting, and other plans. Utilities can share their expectations for interconnection timelines, requirements, processes, and more. This allows both parties to gain a mutual understanding and align on expectations between the utility/independent system operator (ISO) and the customer.

MILESTONE 2
Interconnection Application
The large load customer submits a formal interconnection application with details about demand size, location, technical aspects (design, diagrams, models, etc.), and load ramp-up, accompanied by financial deposits.

MILESTONE 3
Initial Screening and Feasibility Study
The utility may conduct high-level viability assessments for the proposed large load interconnection, focused on items such as the voltage level required for interconnection, access to nearby transmission infrastructure, potential direct-connect network impacts, the need for broader network upgrades, and known obstacles or issues.

MILESTONE 4
Large Load System Impact Study
The utility will perform detailed reliability studies (see Section 7) to quantify the effects the large load has on the transmission and distribution system (if applicable). The studies will analyze the impacts on thermal overloading, system voltages, stability, and other reliability factors. They will also determine the necessary system upgrades needed to alleviate any system performance issues identified.



MILESTONE 5
Large Load Facilities Study
The utility performs a study focused on the detailed engineering designs, substation configuration, protection system upgrades, and other cost estimates required for direct-connect infrastructure modifications. This information is an input into the construction phase of the project.

MILESTONE 6
Signed Interconnection Agreement
The utility/ISO and customer should sign an agreement to formalize the terms and conditions for interconnection. Both parties will draft and negotiate the terms, outlining roles and responsibilities, cost responsibility, schedule, and operational performance expectations, as well as ensuring compliance with regulatory requirements and other industry standards.

MILESTONE 7
Construction and Commissioning
The large load customer constructs the facility itself. Depending on their agreement, the utility and/or customer may construct the electrical facilities required to connect the load. The utility also constructs any broader network upgrades required to connect the facility reliably. The load customer conducts testing and commissioning procedures to verify system readiness. The utility may require documentation and verification that the facility is operating reliably and compliant with applicable requirements.

MILESTONE 8
Post-Interconnection Monitoring and Compliance
The utility and large load customer each monitor reliability of the facility and adherence to requirements and procedures, as applicable. Post-commissioning monitoring equipment (power quality, disturbance reporting, harmonics meters, etc.) may be analyzed to monitor performance. Periodic reviews may be done by the utility or customer to verify compliance with requirements.

Large load interconnection processes vary by transmission provider; however, there are common milestones for a large load interconnection process. SOURCE: ELEVATE ENERGY CONSULTING.

(FERC) Order No. 2023. By evaluating multiple large load requests together, utilities can assess system impacts more holistically, streamline study efforts, and fairly allocate necessary network upgrades. This approach enhances efficiency while ensuring that new loads do not impose undue costs or reliability risks on existing customers.

Developing or improving a structured large load interconnection process requires careful consideration of fairness, efficiency, and long-term grid stability. By adopting best practices from generator interconnection reforms, utilities can modernize their approach, providing a framework that supports growing load demand while maintaining reliability and equitable cost allocation. Figure 4.2 (p. 34) illustrates high-level milestones in the large load interconnection process that utilities could consider.

Each step in the process will have additional details regarding expectations, requirements, deadlines, data sharing, etc. However, having a structured approach such as the one listed above will help emphasize early engagement between the utility and customer, a thorough analysis by the utility, clear expectations and agreements, and continuous oversight throughout the process.

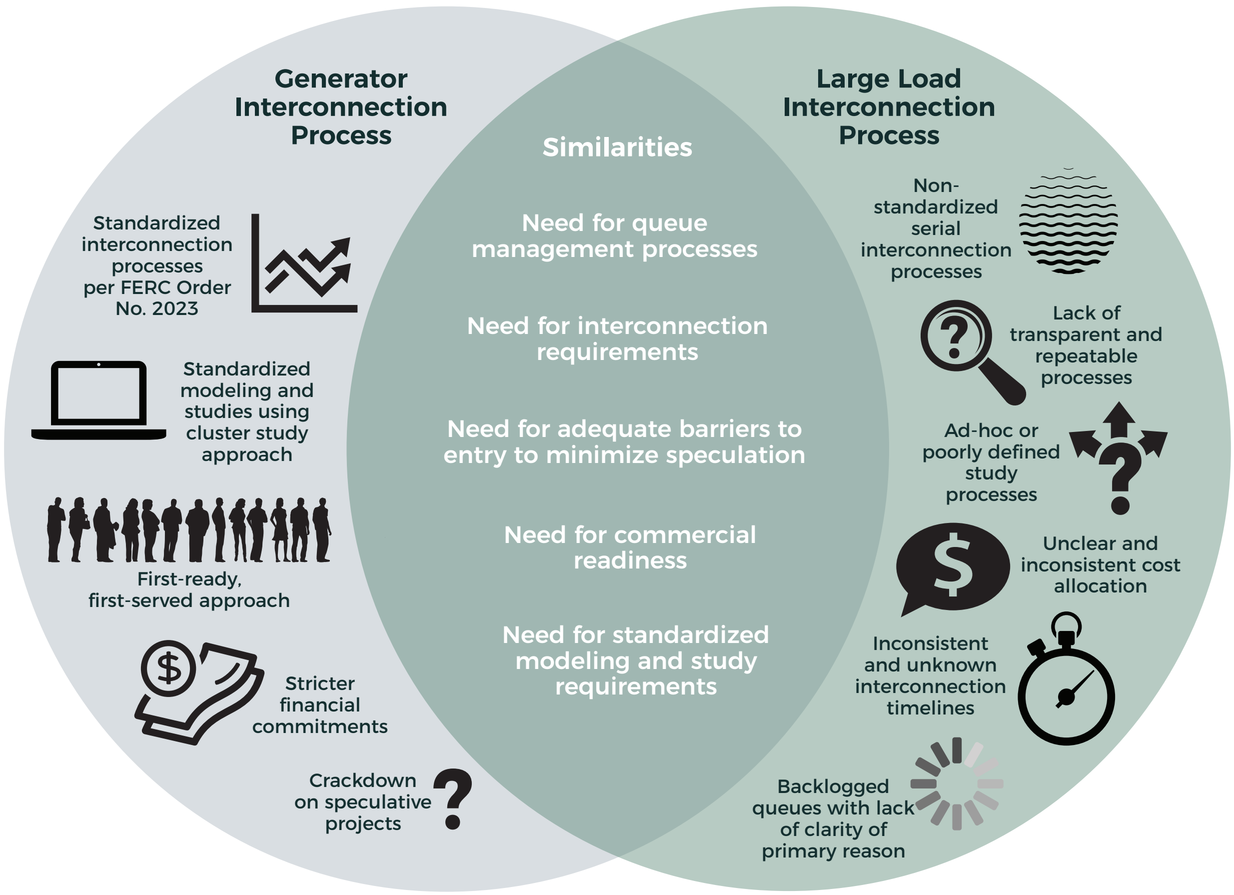
Similarities with Generator Interconnection Reforms and Standards Improvements

Over the past decade, generator interconnection reform has been a focal point for FERC, culminating in Order No. 2023 [14]. This rule sought to address mounting interconnection backlogs, improve study accuracy, and ensure fair cost allocation in response to an influx of renewable generation projects. Prior to these reforms, interconnection queues in regional transmission organizations (RTOs) and ISOs had ballooned, with projects facing delays of three to five years or longer due to inefficient serial study processes and uncertain network upgrade costs as projects dropped out of the queue. FERC Order No. 2023 introduced several measures, including a “first-ready, first-served” cluster study approach, stricter financial commitments from developers, and standardized modeling requirements. These measures aimed to reduce speculative projects clogging the queue and ensure that only viable projects progressed, ultimately benefiting both new generation developers and the reliability of the broader grid [11].

Utilities now face a strikingly similar challenge with large load interconnection. Just as uncoordinated generator interconnection processes led to overwhelmed queues and uncertain system impacts, the rapid influx of high-demand customers such as hyperscale data centers, cryptocurrency mining operations, and industrial electrification projects threaten existing planning frameworks. Many utilities still rely on relatively ad-hoc processes to evaluate large load interconnection requests, leading to inconsistent study timelines, possible gaps in load analysis and grid preparation, uncertainty in

Many utilities may still rely on ad-hoc processes to evaluate large load interconnections which could lead to inconsistent study timelines, possible reliability risks that remain unearthed, uncertainty in upgrade costs and cost allocation, and potential risks to grid reliability.

FIGURE 4.3. Similarities and Differences between the Generator and Large Load Interconnection Processes



The generator interconnection queue and the large load interconnection process have key differences yet also have a number of similarities that industry could learn from as large load interconnection processes mature. SOURCE: ELEVATE ENERGY CONSULTING

upgrade cost allocation, and risks to local grid reliability. Without clearer interconnection requirements, well-defined study methodologies, and structured queue management reforms, utilities risk exacerbating delays, misallocating costs, and overlooking potential system reliability concerns. Applying lessons from FERC's generator interconnection reforms—implementing transparent queue management rules, requiring financial readiness milestones, standardizing studies, etc.—may help utilities create a more efficient, fair, and proactive approach to integrating large loads while maintaining grid stability. Figure 4.3 shows similarities and difference between these processes.

Develop Accurate Large Load Models and Perform Interconnection Studies

The entire large load interconnection study process relies on the customer providing accurate, site-specific, and detailed information regarding the electrical details of the facility across different simulation domains. These studies are critically necessary for ensuring grid reliability, particularly

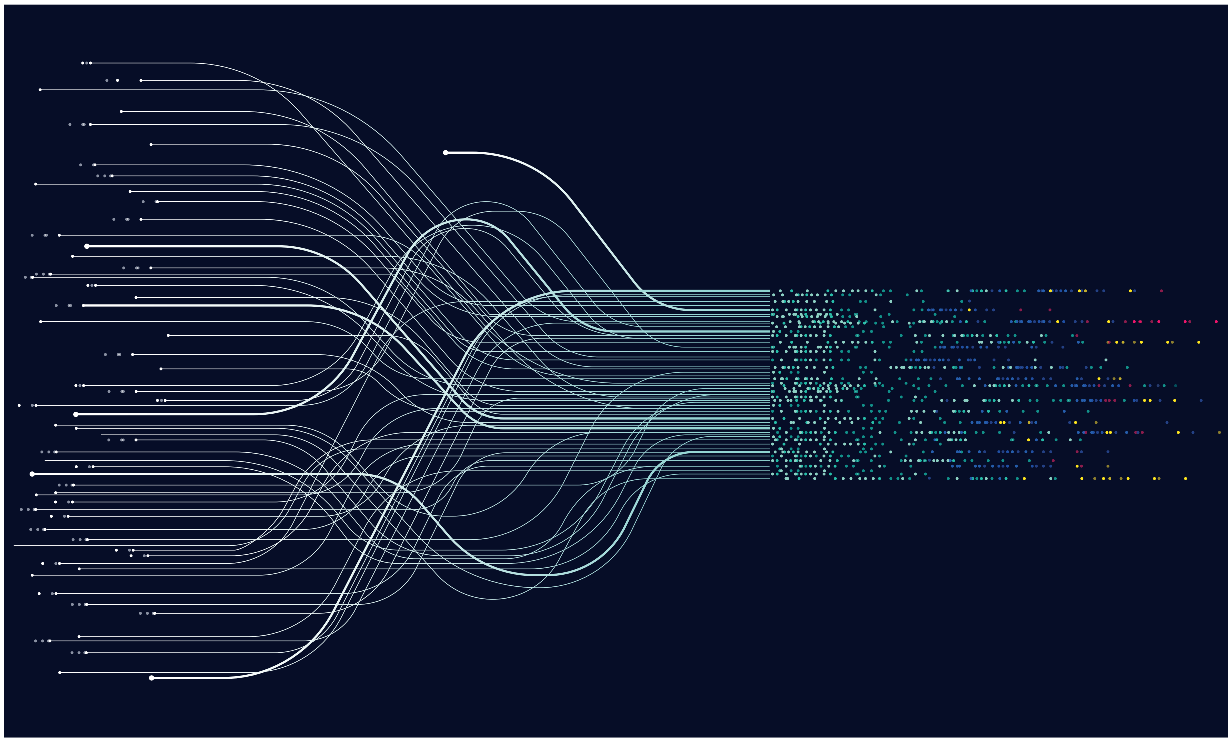


IMAGE: ISTOCKPHOTO/KROT STUDIO

given the size and operational nature of the large loads being connected. Thus, in most cases, basic powerflow studies are insufficient to adequately assess the reliability impacts of large loads on the distribution and transmission system. Different types of models are required based on the studies needed, and determination of the types of studies needed depend on many factors including location, size, technology, etc. Models may include phasor domain transient (PDT) dynamic models (standard library or user-defined), electromagnetic transient (EMT) models (non-manufacturer-specific or manufacturer-specific), a harmonics model, and possibly a short-circuit model if grid-paralleled on-site generation is present. Chapter 6 describes these models in detail. Chapter 7 describes the types of reliability studies performed during the System Impact Study and the Facility Study phases.

Identify Corrective Actions

The results of the interconnection studies will identify if any corrective actions are needed to address potential reliability risks presented by the addition of large loads. These corrective actions may involve a lower demand level that avoids the reliability issues, building new transmission infrastructure or upgrading existing infrastructure (e.g., reconductoring), and other solutions.

It is important to recognize that the solutions should be tailored to the specific reliability issues, and multi-value solutions may play a key role in alleviating multiple reliability risks. For example, if the addition of the load causes grid voltage control or voltage stability issues, these types of challenges can be solved by an array of voltage solutions such as shunt capacitors, static synchronous compensators (STATCOMs), and static var compensators (SVCs). However, if grid strength or fault current levels are also a concern, then synchronous condensers may be a better solution. Lastly, if generation assets are being connected in the area, requiring dynamic reactive capability or grid forming (GFM) batteries could be ideal. Thus, there are many solutions to solve new load issues that can be deployed to solve specific grid reliability risks [15].

Equitably Allocate Costs

The cost allocation of network upgrades should be carefully reviewed to ensure that undue costs are not placed on existing customers. To that end, utilities and state regulators can consider the following steps:

- Use a cost causation principle that ensures that customers triggering the necessity of network upgrades bear an appropriate share of the costs. Direct connection facilities should be paid entirely by the large load customer. Careful attention to cost causation for the broader network upgrades helps avoid shifting undue cost to other ratepayers.
- Identify and differentiate shared and direct assignment costs. Costs can be allocated based on whether they benefit a single customer (direct assignment) or allocated across multiple customers (shared). This could apply to multiple interconnection requests simultaneously or could assign a portion of costs to existing customers.
- Establish cost sharing mechanisms for high-growth areas where network upgrade costs can be equitably distributed among multiple interconnecting customers.
- Use transparent and predictable cost allocation formulas that ensure a clear methodology and a fair and equitable approach. These formulas should be approved by the appropriate regulatory bodies.
- Consider refund and/or credit mechanisms that fairly reimburse early customers who fund system improvements that benefit future customers.
- Again, reduce speculative projects by raising the barrier to entry such that only credible requests are considered and costs are more reasonably assigned.

Construct, Commission, Test, and Interconnect Large Loads

Both the utility and the large load customer will enter a period of engineering, procurement, and construction of their respective facilities to connect the load to the grid. Once those facilities are constructed, adequate commissioning tests are needed to ensure both the load and the grid facilities operate as designed and are tested to ensure personnel and public safety as well as reliable service. Given how fast large loads are growing, utilities are strongly encouraged to play an active role in the large load commissioning process to ensure that they acquire final electrical drawings and documentation, as-left settings, protection and controls, and other data. The final as-left settings of the site should match those used during the interconnection study process, and any discrepancies should be reviewed by the utility. For example, if the as-left protection and control settings are configured in a way that does not align with the utility protection system reclosing schemes, this could lead to systemic risks of data centers tripping offline during normal grid faults. This was a root cause of the large data center event that occurred in Northern Virginia [4].

Lack of coordination and communication between the utility and the large load customer could result in hidden failure modes that could result in catastrophic grid risks. Furthermore, these types of issues result in modeling and study efforts that fail to match reality, further exacerbating the risk of grid reliability issues.

Monitor Operational Performance and Adherence to Requirements

Utilities should require large load customers have adequate disturbance monitoring and operational real-time telemetry so that the utility can adequately assess the operational performance of the site and conduct forensic event analysis when needed. This will include requirements for the large load customer to participate in forensic event analysis efforts conducted by the utility in the event of any abnormal performance detected. These efforts not only help the utility ensure reliable operation of the grid but also can help the customer mitigate any issues that could result in its unexpected tripping or disconnection from the grid, improving operational uptime.

BOX 3: NEED FOR MORE RESOURCES AND STAFF

The industry has broadly struggled, and in some ways failed, to address these types of issues during the construction and commissioning of new generation over the past decade [16]. While work continues to get new generators caught up, the industry cannot afford to make a similar mistake with the forthcoming wave of large loads. Utility leadership, large load developers, and regulatory staff must devote more resources and staff to properly model, commission, and document the capabilities, performance, and as-left settings at these installations. Failure to complete these critical steps can and will introduce catastrophic risks to BPS reliability.

PHOTO: ISTOCKPHOTO/GERVILLE

5

Technical Interconnection Requirements for Large Loads

The large load interconnection process assesses BPS reliability impacts of new large loads and identifies corrective actions necessary to mitigate any reliability risks posed by the new connection. These assessments rely on performance criteria which the newly connecting resource must adhere to. All transmission providers, transmission planners, and planning coordinators have system performance requirements for the transmission system per applicable NERC Reliability Standards [17]. However, they may lack in terms of technical detail for large load interconnections. If large loads can connect without satisfying specific reliability needs, the transmission system could experience a notable degradation of performance and risk. The risk grows when new technologies are introduced on the grid before system planners have gained an adequate understanding of the technology to establish appropriate requirements.

A new level of diligence is required given the degree of highly speculative requests for interconnection driven by speed and minimizing economic impacts.

Historically, industry has not defined comprehensive technical requirements for large load customers because such customers were less common and could be handled on a case-by-case basis. Utilities have also preferred a customer-serving approach that minimizes adverse impacts on end-use customers. This approach worked in the past but is no longer sufficient. A new level of diligence is required given the degree of highly speculative requests for interconnection driven by speed and minimizing economic impacts.

Therefore, to help ensure reliable operation of the BPS, it may be time for transmission providers to define clear, effective, and appropriate requirements for large load customers. Such requirements place demands on prospective customers but—as the utility industry has observed with IBRs—present them with a more transparent and equitable process. All large load customers are held to the same expectations and can proactively prepare and design facilities to meet these expectations along the way.

Learnings from Europe and the UK

The European Network of Transmission System Operators for Electricity (ENTSO-E),[8] established the *Demand Connection Code (DCC),* which was approved by the European Commission in 2016 [18]. The DCC established standardized grid code requirements for different types of demand connections to the transmission system. The regulation applies to new and significantly modified transmission-connected demand facilities, distribution networks connecting to the transmission system, and end-use demand units providing demand response. Of relevance to this paper is the former category: transmission-connected demand facilities (see Table 5.1, p. 42).

As the electric reliability organization in North America, NERC is well suited to take on the role of coordinating these harmonized standards, particularly for transmission-connected large loads.

The United States lacks a similar framework for large load interconnection requirements, leaving a patchwork of regional standards and in many regions no standards at all. This presents an opportunity to establish nationwide harmonized standards and requirements that ensure grid reliability and resilience amid a boom of large load demand in the decades ahead. As the electric reliability organization in North America, NERC is well suited to take on the role of coordinating these harmonized standards, particularly for transmission-connected large loads. The EU's structured approach could inform similar regulatory frameworks in the U.S. for integrating large industrial and data center loads into the transmission system.

PHOTO: ISTOCKPHOTO/SEFA OZEL

8 ENTSO-E is the association for cooperation of the European transmission system operators (TSOs) with 40 member TSOs representing 36 countries, and is responsible for the reliable and coordinated operation of Europe's electricity system.

TABLE 5.1. **High-Level Overview of EU Demand Connection Code Requirements**

Requirement	Details
Frequency Stability	
Disconnection and Reconnection	Facilities must disconnect if system frequency exceeds defined thresholds (e.g., above 51.5 Hz or below 47.5 Hz). Reconnection must be staggered to avoid sudden load surges that could destabilize the grid.
Limited Frequency Sensitivity Mode (LFSM)	Industrial loads must automatically reduce consumption when frequency is too high (LFSM-O) and may increase consumption when frequency is too low (LFSM-U) to help stabilize the grid.
Rate of Change of Frequency (RoCoF) Immunity	Facilities must remain connected during fast frequency changes (e.g., up to 2 Hz/s), preventing unnecessary tripping that could worsen instability.
Voltage Stability	
Voltage Ride-Through (VRT)	Industrial loads must remain connected during voltage dips (e.g., down to 0.15 p.u. for 150 ms) and surges, following defined recovery curves to prevent cascading disconnections.
Reactive Power Capability	Facilities must provide reactive power support within a specified range (e.g., 0.95 lagging to 0.95 leading power factor) to help regulate voltage.
Voltage Setpoint Adjustments	Facilities must allow transmission operators to adjust voltage setpoints dynamically to maintain grid stability.
System Restoration	
Blackstart Contribution	Certain industrial loads must coordinate with transmission operators to adjust demand during blackstart restoration processes, ensuring a stable power-up sequence.
Islanded Operation	Some facilities must be able to operate in islanded mode, supporting grid sections that have been temporarily disconnected from the main system.
Demand Response	
Frequency Control Demand Response	Large loads must be able to adjust power consumption dynamically in response to frequency deviations, with response times as low as 2 seconds.
Voltage Control Demand Response	Facilities must support voltage regulation by adjusting reactive power consumption or generation when requested by the transmission operator.
System Balancing Demand Response	Large industrial consumers participating in balancing markets must meet performance standards for load modulation, including response speed and duration.
Compliance, Monitoring, and Testing	
Pre-Connection Compliance Studies	Facilities must perform system impact studies, including dynamic stability analyses, before receiving approval to connect.
Real-Time Monitoring	Loads above a certain capacity must provide real-time telemetry (e.g., MW, MVAr, voltage) to transmission system operators (TSOs) for continuous monitoring.
Periodic Testing and Reporting	Transmission operators may require periodic testing and compliance reporting to verify that facilities continue to meet grid code requirements.

The EU Demand Code Requirements lay a solid foundation for establishing capability and performance expectations for large loads that the US and other areas can likely learn from. SOURCE: ELEVATE ENERGY CONSULTING

Categories of Large Load Technical Interconnection Requirements

A comprehensive set of technical interconnection requirements for large loads is essential to support a reliable BPS. While a full evaluation is beyond the scope of this paper, transmission providers and ISO/RTOs should consider the following high-priority categories:

- **Load Interconnection Size Limits:** Historically, the loss of a single large end-use load has not posed significant reliability risks, as many customers sought multiple service connections for redundancy. However, as load interconnection request sizes grow, single points of connection may introduce new reliability challenges. Advances in digital service transfer between data centers reduce the need for multiple service points, making it critical for transmission providers to assess the risks associated with losing single or aggregated large loads. To mitigate these risks, transmission providers may impose interconnection size limits such as capping the amount of load at a single point of connection or limiting the number of direct-connect tapped loads [5]. It may also be possible to ramp up the requirements and gating as the interconnection size becomes larger.
- **Model Sharing:** Transmission planners should define modeling requirements for large loads across power flow, transient stability, electromagnetic transient (EMT), and short-circuit studies. Required models should include equipment characteristics, control narratives, and verification details. Grid planners must specify whether standard library models suffice or if user-defined models are necessary, ensuring accurate models for use in grid planning and operational studies.
- **Data Recording and Monitoring Requirements:** Large load customers should have recording and monitoring data to support real-time monitoring, event analysis, and model validation. Required data sources may include SCADA telemetry (e.g., breaker status, voltage, current, power), sequence of events recording (SER), digital fault recording (DFR), dynamic disturbance recording (DDR), and power quality monitoring. Not all data may need to be transmitted in real-time; in some cases, data can be stored locally for quick retrieval upon request. This large load monitoring data should be shared with transmission providers to support event analysis activities, confirm operational characteristics and performance, and validate technical performance requirements of the large load facilities.
- **Voltage and Frequency Ride-Through Requirements:** Electric reliability organizations and/or ISO/RTOs should establish large load ride-through requirements, defining the voltage and frequency ranges for which large loads must remain connected. Without these capabilities, large loads may trip unexpectedly during disturbances, exacerbating grid instability. Ride-through standards should align with industry guidelines such as NERC PRC-024, NERC PRC-029, and IEEE 2800-2022.
- **Power Factor and Reactive Power Requirements:** Large load facilities must operate within a defined power factor limit, typically ±0.95, to manage reactive power impacts on system stability. For large loads, tighter limits may be necessary to prevent excessive reactive power consumption. Customers unable to meet these standards may need to install power factor correction (e.g., shunt capacitors, reactors) or dynamic compensation devices such as STATCOMs to support voltage stability, and may require more detailed power quality and dynamic reactive power resource studies.

PHOTO: ISTOCKPHOTO/GERVILLE

- **Power Quality Requirements:** Transmission providers should enforce power quality standards to protect grid stability and customer infrastructure. Key criteria include voltage range compliance (ANSI C84.1), harmonic distortion limits (IEEE 519), flicker mitigation (IEEE 1453), phase imbalance control (IEC 61000-3-13), and transient surge protection. Compliance testing and periodic reporting should be required, with corrective actions enforced for non-compliance. Specialized studies and monitoring equipment may be required to adequately protect existing customers.
- **Oscillation Requirements:** Large load facilities must not introduce or amplify oscillations that could destabilize the grid. Loads with power electronics, motor drives, or cyclical operation must be assessed for forced oscillation risks. Facilities near series-compensated lines, synchronous generation, or large inverters should undergo EMT studies to evaluate SSO risks. Pre-operational assessments, real-time monitoring and protection, and forensic event analysis should be implemented to detect and mitigate oscillatory disturbances. It is important to be clear and specific when defining requirements for oscillations. For example, quantification of the maximum level of oscillation at each voltage level, as well as the allowed frequency content of the oscillations, will determine the cost of mitigation on the part of the load customer.
- **Short-Circuit Requirements:** Transmission providers should define minimum and maximum short-circuit current levels at the customer interface to ensure the customer rates equipment appropriately. If a facility configuration contributes to excessive fault currents, customers may be responsible for mitigation measures identified in the interconnection study process.
- **Protection Requirements:** Protection coordination studies should extend beyond circuit-level protection to include facility-level schemes. Coordination should cover UPS/rack-level protection for data centers, ensuring integration with utility systems. Utility protection departments are

already resource constrained, so standardized approaches and industry guidelines in this area would be valuable moving forward. Utilities should have visibility into critical facility protection and control systems to coordinate responses to faults, reclosing events, and UPS load pick-up and/or trip conditions. If backup generation operates in parallel with the grid, studies must evaluate fault contributions, breaker duty impacts, and coordination with utility system protection schemes.

- **Data Sharing Requirements:** In addition to providing models, large load customers must provide operational and planning data to support system modeling, reliability assessments, and real-time operations. Required data may include load forecasts, equipment specifications, real-time telemetry, outage and maintenance notifications, and event logs. Submission must adhere to utility-defined formats and update frequencies.
- **Operations and Control Requirements:** Large loads must operate in compliance with utility-defined operational reliability criteria. This may include ramp rate limits, real-time dispatchability, voltage/reactive power support, and ride-through capabilities. Automated and manual controls should be in place to respond to utility directives during normal operations and emergency conditions.
- **Communication with Utility Requirements:** Secure, reliable communication channels must be established between large load customers and utilities to enable real-time monitoring, coordination, and emergency response. Communication protocols should align with industry standards (e.g., IEEE, IEC 61850, NERC CIP) and support SCADA integration, event reporting, and 24/7 availability of key personnel.
- **Emergency Response and Coordination:** Large load customers must maintain an emergency response plan outlining contingency actions, communication protocols, and coordination with the utility during blackouts, frequency/voltage excursions, cyber incidents, or natural disasters. Designated personnel must be available for emergency coordination and drills as required. Facilities with backup generation or islanding capabilities must follow approved procedures for safe transitions.
- **Operations and Maintenance Requirements:** Large load customers must maintain electrical infrastructure, protection systems, and control equipment per utility and industry standards. Scheduled maintenance that could impact grid reliability must be coordinated in advance, and emergency maintenance must be reported immediately. Compliance with utility inspection, testing, and reporting requirements is mandatory. Maintenance requirements for the utility's interconnecting equipment must also be clearly defined and allow so the utility can provide periodic maintenance and testing of its electrical equipment.
- **Backup Generation Requirements:** Facilities with onsite backup generation must disclose details on capacity, operational modes, protection schemes, and interconnection status. Backup generators operating in parallel with the grid require fault contribution analysis and coordination with protection schemes. Utility approval may be needed for parallel operation, blackstart capabilities, and transfer switching arrangements.

- **Demand Response Requirements:** Large load customers participating in demand response programs must comply with dispatch signals, response times, and performance verification criteria. Load curtailment or shifting should be coordinated to minimize adverse grid impacts while aligning with market and reliability requirements. Customers must provide performance data to the system operator to verify compliance.
- **Cybersecurity Measures:** Large load facilities must implement cybersecurity protections to safeguard grid operations from cyber threats. Requirements may include secure authentication, encrypted communications, firewall protections, and compliance with applicable standards such as NERC CIP, ISO/IEC 27001, or NIST frameworks. Utilities may conduct audits, request compliance evidence, and require corrective actions. In severe cyber incidents, emergency disconnection may be necessary.
- **Utility Right to Monitor and Enforce Compliance:** Transmission providers must have the authority to monitor, verify, and enforce compliance with interconnection requirements to ensure system safety and reliability. This includes real-time operational data access, site inspections, and compliance testing. If a facility is found non-compliant, utilities must have the authority to mandate corrective actions at the customer's expense. If non-compliance poses reliability or safety risks, utility operators must be empowered to exercise disconnection rights as outlined in interconnection agreements.

All requirements should be grounded in the need for ensuring an adequate level of BPS reliability, and costs for large load customers should be considered in defining reasonable yet necessary requirements that support the BPS while minimizing excessive costs to all customers. The size and nature of the new class of loads being connected to the system today necessitates the introduction of increased standards for interconnection. Failure to implement new, robust standards is placing unprecedented risk on the bulk electric system.

The size and nature of the new class of loads being connected to the system today necessitates the introduction of increased standards for interconnection. Failure to implement new, robust standards is placing unprecedented risk on the bulk electric system.

Appendix B provides more details on each of the topics listed above.

6

Large Load Modeling Considerations

Accurate models are necessary for transmission planners to study the reliability impacts of large loads connecting to the BPS. Customers must address any issues identified by planners before connecting to ensure reliable operation for all customers and to avoid system instability, uncontrolled separation, or cascading outages. Some utilities may require the large load customer to prepare and submit the models and supplemental documentation for review. Other utilities may prepare models themselves based on documentation provided by the customer.

In any case, the following models are generally required by the utility:[9]

- **Positive Sequence Powerflow Model:** Represents the steady-state operating conditions of the facility, including real and reactive power consumption, voltage levels, and network topology. This model is essential for assessing thermal loading, voltage stability, and contingency analysis.
- **Phasor Domain Transient (PDT) Dynamic Model (standard library model):** Uses standard model components in commercial software platforms (e.g., PSLF, PSS®E, PowerWorld) to represent the dynamic response of the facility to system disturbances. Suitable when load behavior can be captured using predefined library models.
- **PDT Dynamic Model (user-defined model):** Required when standard library models are insufficient to represent the facility's dynamic behavior such as unique power consumption characteristics, variable or oscillatory behavior, special control schemes, or power electronic interfaces. This model may be provided as a compiled DLL or equivalent for compatibility with utility simulation tools.
- **Electromagnetic Transient (EMT) Model (not manufacturer-specific):** Captures high-frequency and fast-response behavior of power electronics and control systems, as well as unbalanced conditions. This model is useful for evaluating voltage flicker, studying sub-synchronous impacts on generators due to variation in load output, and other impacts. Typically developed in EMT software such as PSCAD, EMTP-RV, or ATP.

9 The section does not discuss production cost modeling or capacity expansion modeling.

- **EMT Model (manufacturer-specific):** Captures highly detailed responses from the load, often representing power electronic interfaces specific to the equipment suppliers used in the plant. These models may be necessary for assessing interactions with nearby IBRs, assessing SSTI and SSCI, creating harmonics models (described below), or in some cases evaluating ride-through capability.
- **Short-Circuit Model:** Represents the fault current contribution of the facility, including contributions from rotating machinery, transformers, and power electronic interfaces including batteries and UPSs. This model is used for the coordination of protection schemes between the utility and large load facility and for system protection impact assessments. These models are typically provided in formats compatible with short-circuit analysis tools like ASPEN OneLiner, CYME, or CAPE.
- **Harmonics Model:** Details the harmonic emissions of the facility, including expected current and voltage harmonic distortion levels under normal and contingency conditions at varying load levels. This model must accommodate the harmonic impact from all the major components of the load plant. Essential for evaluating compliance with IEEE 519 limits and assessing potential resonance issues with system impedance characteristics. Typically developed using tools such as ETAP, PSCAD, CYME, or Harmonic Analyzer in DIgSILENT PowerFactory.
- **Documentation:** All models should be accompanied by sufficient documentation that includes equipment characteristics, control narratives, verification details, and how to use the models (where applicable). This ensures that utility planners can correctly interpret and apply the models in their studies.

The following sections provide a cursory overview of the different types of models that may be used in reliability studies today, with a specific focus on data center modeling.

Data Center Load Composition

Each data center load model should be developed and verified based on a detailed review of the site design and its specific operational characteristics. Percentages of load composition vary depending on the size of the facility, cooling method, density of power electronic equipment, type of servers and workloads, external temperature, load cycling, types of power conditioning equipment, etc. However, a high-level estimate of data center load composition can help improve overall awareness, data quality, and reasonability checks in the absence of actual data.

Data centers are typically comprised of the following end-use load components (see Table 6.1, p. 49) [19], [20]:

Percentages of load composition vary depending on the size of the facility, cooling method, density of power electronic equipment, type of servers and workloads, external temperature, load cycling, types of power conditioning equipment, etc. However, a high-level estimate of data center load composition can help improve overall awareness, data quality, and reasonability checks in the absence of actual data.

- **Power Electronics:** Highly nonlinear power draw, primarily from servers based on digital workloads and type of infrastructure. Power consumption from networking equipment and storage is minor by comparison.
- **Cooling Systems:** Continuous yet variable demands dependent on external weather conditions (e.g., ambient temperature). Consists of large 3-phase motor loads and some smaller 1-phase auxiliary loads. Variable frequency drives (VFDs) used extensively for fans and pumps to improve energy efficiency; redundant systems often available to avoid data center downtime due to cooling issues.
- **Power Infrastructure:** May introduce harmonics emissions from rectifiers and inverters. Could cause switching transients, interactions with other power electronic devices such as IBRs, voltage and frequency ride-through effects, etc.

The information in Table 6.1 pertains to the consumption of electricity, and this allocation of end-use load is less relevant to modeling these loads in grid reliability studies. For example, the power electronics interface with the AC grid through a UPS or a PDU and thus need to be modeled accordingly. Details regarding how data center load composition is considered in load modeling is described in subsequent sections.

TABLE 6.1.
Estimated Data Center Load Composition

Category	Load %	Description
Power Electronics	40–60%	**Servers (30–40%)** Rack-mounted and blade servers for compute workloads driven by CPUs, GPUs, and TPUs for AI, machine learning, and cloud **Storage Systems (5–10%)** Hard disk drive (HDD) and solid-state drive (SSD)/flash memory **Networking Equipment (5-10%)** Switches, routers, firewalls, and other communication equipment
Cooling Systems[a]	20–40%	**Computer Room A/C or Handlers (CRAC/CRAH Units) (10–20%)** Traditional air-cooled chillers, condensers, and compressors to maintain server room temperatures **Immersion and Direct-to-Chip Cooling (5–10%)** Emerging for high-density AI workloads, which reduces air cooling demand **Cooling Tower Pumps & Fans (5–10%)** Includes water-cooled systems and evaporative cooling units
Power Infrastructure[b]	10–15%	**Uninterruptible Power Supplies (UPS) (5–10%)** UPS systems convert AC electricity to DC and then to AC, providing fast transition to backup energy **Power Distribution Units (PDU) (2–3%)** PDUs convert high-voltage power to IT-friendly levels

a Many of the cooling system components are industrial 3-phase motors. The fans and pumps in particular use VFDs for energy efficiency purposes and are thus electronically connected to the AC grid.

b The power infrastructure equipment are electronically connected to the AC grid.

SOURCE: ELEVATE ENERGY CONSULTING.

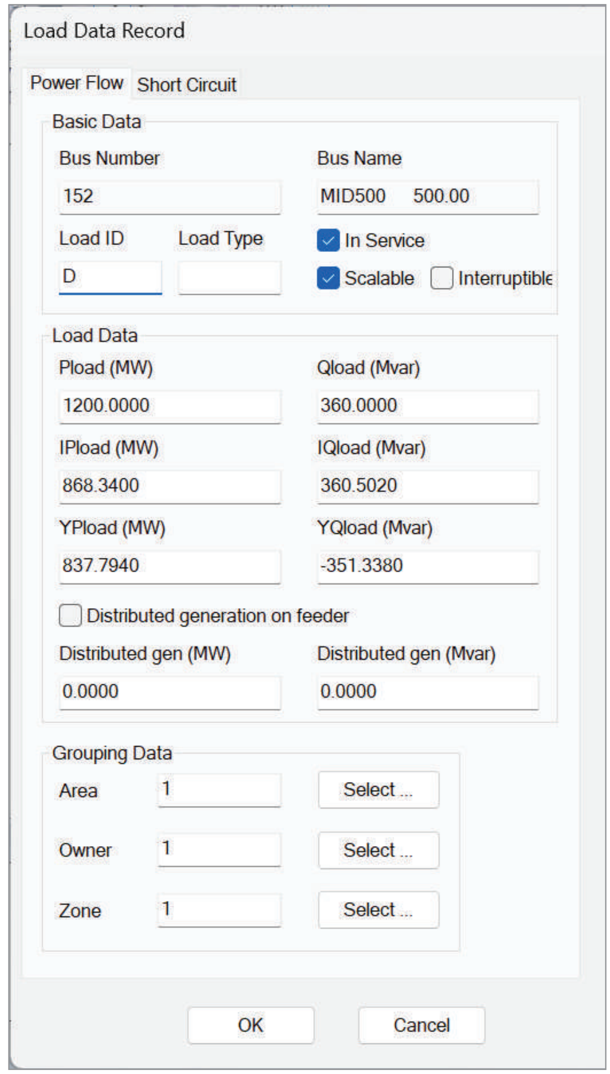
Note that the list above excludes substation equipment such as power conditioning equipment (e.g., STATCOMs), power factor correction such as shunt capacitors or reactors, or on-site backup generation (diesel gensets or BESS).

Powerflow Modeling

Steady-state power flow model representation includes a bus number, bus name, load ID, and snapshot representation of the active and reactive power consumption of the load for the given system conditions. Some simulation platforms have fields for scalability and any interruptible nature of the load. The load is assigned an area, zone, and owner ID code and may have specific parameters for representing behind-the-meter generation (although this may be explicitly modeled if sufficiently large). Figure 6.1 (p. 50) provides an example of a load record in the power flow case.

The utility may provide guidance as to how the active and reactive power demand should be modeled, and these values may be adjusted by the transmission planner during studies based on information supplied to them during the application process. For example, seasonal variations in cooling demand at the large load facility due to ambient temperate differences between winter and summer will need to be reflected in the model based on information supplied by the load customer.

FIGURE 6.1.
Powerflow Load Model Representation



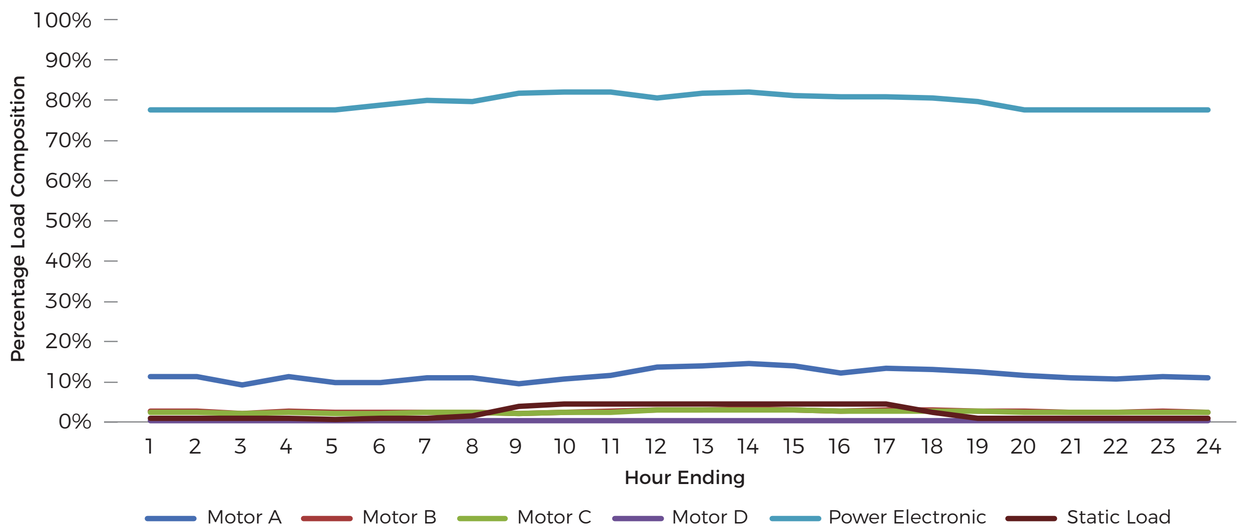
SOURCE: SIEMENS PTI.

Positive Sequence Dynamic Load Modeling

There are various standard library dynamic load models used in stability studies; each has its benefits and drawbacks. One of the more common dynamic load models is the composite load model [21]. The composite load model includes the following elements:

- **Collector System Equivalent:** Equivalent collector system impedances (resistance, reactance, susceptance).
- **Motor Loads:** Four types of motor loads including:
  - **Motor A:** 3-phase, constant-torque compressors used in air conditioning and refrigeration.
  - **Motor B:** 3-phase, higher-inertia fans whose torque is proportional to speed.
  - **Motor C:** 3-phase, lower-inertia pumps whose torque is proportional to speed squared.
  - **Motor D:** Single-phase air-conditioning compressors.
- **Power Electronic Loads:** Basic constant power load that ramps down based on voltage.
- **Static Load:** Conventional static load representation.
- **Distributed Generation:** Aggregate distributed energy resource (DER) representation.

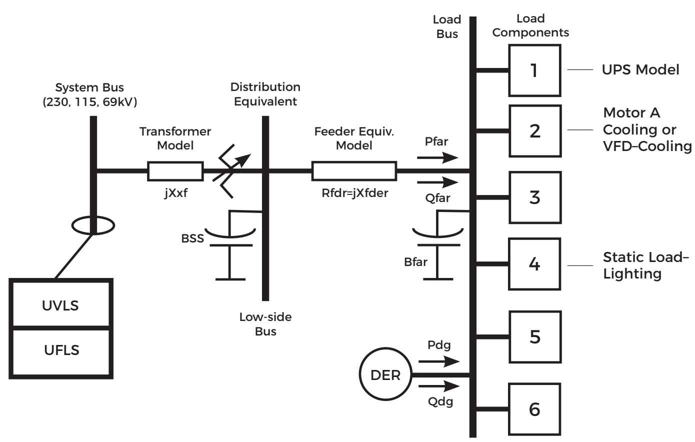
FIGURE 6.2. Percentage Load Composition for Composite Load Model Components



The majority of end-use loads at large data centers is power electronic. SOURCE: ELEVATE ENERGY CONSULTING.

The fractional percentage of the load composition must be assigned to the different load components. For example, in the WECC region, a default "data center" load model has been developed and is used for interconnection-wide base case creation and standard data center load modeling [22]. Figure 6.2 shows the load composition assumption for data center load over the course of a typical day. As the graph shows, almost 80% of the load is defined as power electronic, about 10% is Motor A, and the remaining 10% is Motor B, Motor C, and static load. Thus, the power electronic representation dominates the dynamic response of the load.

FIGURE 6.3. Evolving Composite Load Model Capabilities



Changes to the composite load model may enable a more accurate representation of data center loads in the future.

SOURCE: ELEVATE ENERGY CONSULTING. ADAPTED FROM EPRI..

The model was originally developed to represent aggregate loads connected throughout a distribution system, not individual large loads.[10] Researchers are investigating improvements to these models currently (see Figure 6.3) [23]. However, due to the lack of standard library dynamic load models available in the commercial software platforms, industry has used this model to fit other load types.

10 The model also includes a DER_A dynamic model component intended to represent aggregate amounts of distributed energy resources such as rooftop solar systems. Thus, it may be inadequate to represent co-located generation at large load facilities.

Technological advancements are far outpacing industry modeling improvements efforts to develop standard library models, which could lead to inaccurate modeling and potential reliability risks as data center load integration continues. Given these limitations, it may not be sufficient to continue modeling large loads such as data centers with simplified models such as the composite load model; industry may need to turn to more customized models to reduce risk.

User-Defined Dynamic Models

Existing standard library dynamic load models in commercial software programs lack sufficient control and protection components to properly model large loads such as data centers. Recent events in Northern Virginia and ERCOT have indicated that some large loads are highly voltage sensitive. For example, grid disturbances that are not very severe (e.g., shallow voltage dips with voltage that only reaches 85% of nominal) can lead to significant reduction of large loads. Furthermore, consecutive voltage dips that may occur typically during auto-reclosing attempts could lead to partial or full tripping of large loads. Neither of these phenomena can be currently captured using standard library load models. Furthermore, peculiar behavior of these loads even during normal grid conditions such as large and rapid fluctuations in power consumptions, as illustrated earlier in this report, may necessitate more sophisticated dynamic models. Therefore, a user-defined model may be necessary to capture such characteristics. In-depth and thorough understanding of the large load's behavior under normal and abnormal grid conditions is crucial for developing accurate and reliable user-defined dynamic models.

Electromagnetic Transient Modeling

EMT models are the highest-fidelity models used by power systems engineers for reliability analysis. These models represent the load and the grid in sufficient detail to accurately represent system

IMAGE: ISTOCKPHOTO/NICO EL NINO

behavior during very fast events. The models typically are created with specific studies in mind and can vary in complexity and construction depending on what is being analyzed. For example, the following types of studies will require different elements to be represented accurately within the EMT model:

- **Detailed Ride-Through Evaluation:** Protection systems within the controls and plant relaying should be included in the model in sufficient detail to accurately disconnect the plant during grid faults of various severities and types, as well as frequency excursions and voltage transients. This includes the various protective systems in PDUs, VFD-based cooling systems, UPS load take-up logic, and others.
- **SSO Impacts:** If synchronous generators are nearby, the EMT model must have the capability to flexibly represent the possible range of oscillations or continuous variations in power consumption. Studies that evaluate the impact on generator shaft systems must also include a higher layer of detail in the synchronous generators. For studies evaluating SSTI and SSCI, correct representation of damping within the load is also required. This typically requires the EMT model for key components such as PDUs and UPS units to be specific to the individual equipment suppliers.
- **High-Frequency Impacts:** For special evaluation of higher frequency effects like harmonics or transients, the EMT model of the load and nearby system should consider impact of frequency on electrical characteristics of each component. For evaluating harmonic impact or creating harmonic models, the load model should also include the correct representation of switching and control circuits within each element, which may require manufacturer specific information.
- **Interactions with IBRs:** To correctly represent the impact of the load on nearby IBR control or protection circuits, the EMT model of the load should include correct dynamic representation at the frequencies of concern to the IBR. For example, if a STATCOM is installed nearby to mitigate voltage fluctuations caused by the load, the STATCOM could incorrectly interpret these fluctuations as system instability and act to protect itself. The EMT model should therefore include an accurate representation of the range of possible fluctuations, as well as the STATCOM controls.

In general, EMT models must be carefully specified and requested by the utility with a firm understanding of their end use in mind. Given that specification, they must be carefully constructed using detailed information about the ultimate load plant design.

In general, EMT models must be carefully specified and requested by the utility with a firm understanding of their end use in mind. Given that specification, they must be carefully constructed using detailed information about the ultimate load plant design.

Short-Circuit Modeling

Short-circuit models and studies are performed in order to adequately set the protection and control systems of a facility under various worst-case fault conditions. These studies aim to ensure that protection systems are both dependable and secure, ensuring that any faulted equipment is reliably tripped offline as quickly as possible under all scenarios, while also ensuring that any non-faulted equipment remains electrically connected and is not unintentionally tripped offline. Protection and

PHOTO: ISTOCKPHOTO/STREKOZA2

control systems between the utility and large load facilities must be closely coordinated to ensure reliable and secure performance of these systems, and likely may include some form of communications-assisted schemes between both sides of the interconnection. Critical components of the large load facility must be appropriately modeled in these short-circuit models, including maximum ramp rates of the load, grid-connected backup generation of the facility, any power quality impacts from the operational characteristics of the facility, and transfer switch functionality and settings.

Harmonics Modeling

Harmonics studies are typically performed in conjunction with measurement-based evaluations to understand the potential for equipment damage. Since the studies can be very complex and ultimately drive the design of expensive mitigation such as large filters, the models used in the studies must be as accurate as possible and minimize the use of “worst-case” assumptions. Creation of these models often utilizes either available measurement data (in cases where similar equipment already exists in operation), or detailed EMT models that correctly represent component harmonic injections. In both cases, the final harmonic model is typically either a voltage source or current source with an associated impedance. This representation varies with harmonic frequency and often varies with the operating point of the load.

7

Large Load Interconnection Studies

Utilities must conduct reliability studies when a new large load seeks interconnection to the grid. These studies quantitatively identify whether the large load can be reliably integrated to the BPS or whether network upgrades are needed to ensure reliable operation within acceptable performance limits. Transmission providers may have a defined study process that outlines how these studies are conducted, and this process may or may not be publicly available for prospective customers. Regardless, the process generally includes the studies shown in Figure 7.1. Each of these studies are described briefly in this chapter.

FIGURE 7.1. Types of Reliability Studies for Large Load Interconnection Studies

Powerflow Studies

- Thermal overloads and voltage violations
- Congestion and available transmission services

Transient Stability Studies

- Angular stability and electro-mechanical oscillation
- Voltage stability, ride-through performance, etc.

EMT Studies

- Complex stability phenomena
- Power electronic interactions and oscillations

Short-Circuit Studies

- Breaker duty, protection coordination, co-located generation

Some of the more common reliability studies used for studying large load interconnections. SOURCE: ELEVATE ENERGY CONSULTING.

Regulatory Guidance

The NERC FAC-002 Facility Interconnection Studies standard requires each Transmission Planner and each Planning Coordinator to study the reliability impact of "interconnecting new generation, transmission, or electricity end-user Facilities," as well as existing facilities "seeking to make a qualified change." The standard specifies the following studies [24]:

- The reliability impact of the new interconnecting facility.
- Adherence to applicable NERC Reliability Standards, regional and Transmission Owner planning criteria, and facility interconnection requirements.
- Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions.
- Study assumptions, system performance, alternatives considered, and coordinated recommendations.

Further guidance is available in the NERC TPL-001 *Transmission System Planning Performance Requirements* standard, which defines performance criteria for the BPS and serves as a starting point for contingency definitions. Utilities can have more stringent requirements, but the NERC standard establishes a ***minimum*** bar.

In particular, the NERC TPL-001 standard Table 1 includes the steady-state and dynamic stability performance planning events, defined as P0–P7 (see Table 7.1) [25]. Each category of transmission planning event includes whether non-consequential load loss and interruption of firm transmission service are allowed.

TABLE 7.1. NERC TPL-001-5.1 Table 1

Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault[7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault8 (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker)[8]	SLG	EHV, HV	Yes	Yes

CONTINUED ON PAGE 57

TABLE 7.1. NERC TPL-001-5.1 Table 1 (CONTINUED)

Category	Initial Condition	Event[1]	Fault Type[2]	BES Level[3]	Interruption of Firm Transmission Service Allowed[4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency (Fault plus stuck breaker[10])	Normal System	Loss of multiple elements caused by a stuck breaker[10] (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV, HV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer[5] 4. Shunt Device[6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency (Two overlap-ping singles)	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer[5] 3. Shunt Device[6]	3Ø	EHV, HV	Yes	Yes
		5. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Note: The footnotes above are identified in the NERC standard and should be referenced directly from the standard, if needed.

SOURCE: RECREATED FROM NERC.

Powerflow Studies

Powerflow and contingency studies are the foundational tools for power systems analysis, and are used to identify any thermal overloads and voltage violations under normal and contingency operating conditions. These studies also consider the effect of regional shifts in power transfers and outline any network upgrades required to mitigate the performance violations they identify. In some cases, powerflow tools are also used to assist in power quality analysis and flicker evaluation.

Considerations for these studies include:

- **Study Case Selection:** The most stressed study cases spanning a range of operating conditions (e.g., peak summer, peak winter, spring) to ensure reliability in all cases.
- **Load Level Assumptions:** Load at the full power consumption proposed in the customer contract, including worse-case power factor (i.e., reactive power demand) operating conditions.
- **Load Service:** A means of defining load study assumptions. Types may include:
    - **Firm Loads:** Requires network upgrades for power consumption beyond the level at which the thermal overloads or voltage violations occur.
    - **Controllable/Flexible Loads:** May be able to connect at higher demand levels, with agreement that the utility may curtail the load or dispatch it to a lower level to address specific network performance issues. This approach will likely differ between utilities and regions based on their system operating limit procedures.
- System Performance Deficiencies and Solutions: Potential system performance deficiencies that can affect reliability, along with solutions to overcome them. Solutions should consider a range of options, including transmission infrastructure investment and more advanced technologies. Types of solutions depend on the specific performance issue.

Transmission system upgrades are expensive, and a detailed discussion of how to allocate these costs lies beyond the scope of this paper. In general, larger transmission system upgrades can provide additional value to customers, unlock generator interconnections to meet regional or state policies, and support utility long-term planning. These impacts should be considered, and costs can be allocated fairly and equitably for the large load customer and existing ratepayers. However, multi-value alternative solution options should also be considered alongside expensive network upgrades to create a diverse and flexible system.

Transient Stability Studies

Transient stability studies explore and identify any stability-related issues that may arise with the connection of a new large load. They typically study a smaller subset of contingencies where potential instability risks are greatest. The transmission planner should have a process for identifying these contingencies and specifying the cases being studied.

Specific areas of focus for these types of studies include:

- **Angular Stability and Impact on Nearby Generation:** Ensuring that nearby generating units remain stable for new or modified contingencies and that large, fast changes in the load do not strain the mechanical systems of the generators unduly.
- **Impacts to Stability-Limited Transfer Paths:** Ensuring larger system-level stability metrics are met, particularly for intra-area or inter-area path flows across the system.
- **Transient Voltage Recovery:** Ensuring that the load does not adversely affect the ability of the system to recover voltages after a fault or other event.
- **Voltage Stability:** Ensuring that there is sufficient dynamic reactive support in the area to maintain reliability during and immediately following large events.
- **Large Load Ride-Through and Dynamic Performance Assessment:** Ensuring that the load can suitably ride through grid disturbances and that the dynamic response of the load does not have any adverse impacts on the system. This may require additional load protection system modeling beyond the standard library models and may require even more detailed analysis, as described below. In addition, the impact of possible ride-through failure on the system must be assessed.
- **Impacts on Local and Inter-Area Electromechanical Oscillations:** Ensuring there are no adverse impacts on local or inter-area oscillatory modes. This generally will require custom dynamic load modeling beyond standard library models, particularly when studying the effect of forced oscillations driven by cyclic load behavior from facilities like AI data centers.

EMT Studies

Electromagnetic transient (EMT) simulations are increasingly necessary due to the electronic nature of large loads such as data centers and the potential interactions these loads can have on other grid-connected components. EMT studies represent the data center and the surrounding grid in much more detail than conventional positive sequence stability studies and can study and identify more complex reliability risks. Examples of phenomena studied using EMT simulations include, but are not limited to:

- Impact on synchronous generator shaft systems.
- Sub-synchronous oscillations and torsional interactions.
- Harmonics and power quality.
- Capacitor switching transients and other types of transients.
- Inverter-based technology controller interactions.
- Ride-through evaluation and load take-off.
- Other complex stability phenomena.

Short-Circuit Studies

Short-circuit studies assess fault current levels, ensure equipment remains within acceptable fault duty ratings, and establish and verify protection settings for both the customer and the utility. These studies ultimately protect both the electrical infrastructure and the personnel working at these facilities.

While data centers are not a significant contributor of fault current, their electrical impedance characteristics will influence fault current levels and protective relay settings, particularly around the interconnection location. Thus, any new facilities study will ensure protection system coordination, identify upgrades required for direct interconnecting facilities, and screen for unacceptable impacts on the BPS. Utilities also conduct arc flash studies to ensure safe working distances and personal protective equipment requirements.

Co-Located Projects

With the transmission system increasingly congested, co-location of generation and load facilities has become increasingly attractive [26]. Many data centers are paired with or seek location alongside existing generating facilities. Many others pursue a “bring your own generation (BYOG)” approach, where the data center and generating facilities are developed together. These approaches may enable energy suppliers and large load developers to ramp up operations more quickly and leverage the grid for additional expansion if and when possible. It may also enable utilities to reduce burdens while seeking to ensure the same levels of reliability and cost for existing ratepayers.

New development models and partnerships are introducing large campuses of data centers driven by hyperscalers and combined with generation resources. These partnerships assure a power offtaker for the generation developer and spur development of the data center. The large parks may also be able to provide grid services and participate in wholesale electricity markets. However, this is an evolving landscape with regulatory obstacles, uncertainty regarding tariffs, and other factors. A lack of standardized frameworks for handling large loads, particularly large load co-location with generation, may be slowing development.

As a result, it is difficult to characterize how to study the addition of these resources and in which utility interconnection process they belong. Considerations include which study assumptions to use based on the generation and load agreements in place, the type of load service, and whether the resource (load and generation) is providing grid services.

8

Solutions for Bulk Power System Risk Mitigations for Large Loads

Rapid growth of large load consumers, particularly data centers, presents significant challenges for grid reliability, infrastructure planning, and real-time operations. Data center interconnection requests exacerbate challenges across the board: demand forecasting, minimizing stranded assets, supply chain issues, managing transmission system congestion, handling grid voltages and system stability margins, resource adequacy concerns, and policy implications. Utilities have many ways to mitigate these challenges. This section outlines some of the technical solutions being considered by industry today; however, this is not intended to be a comprehensive list.

Baseline Operational Performance Requirements Solutions

TECHNICAL INTERCONNECTION REQUIREMENTS

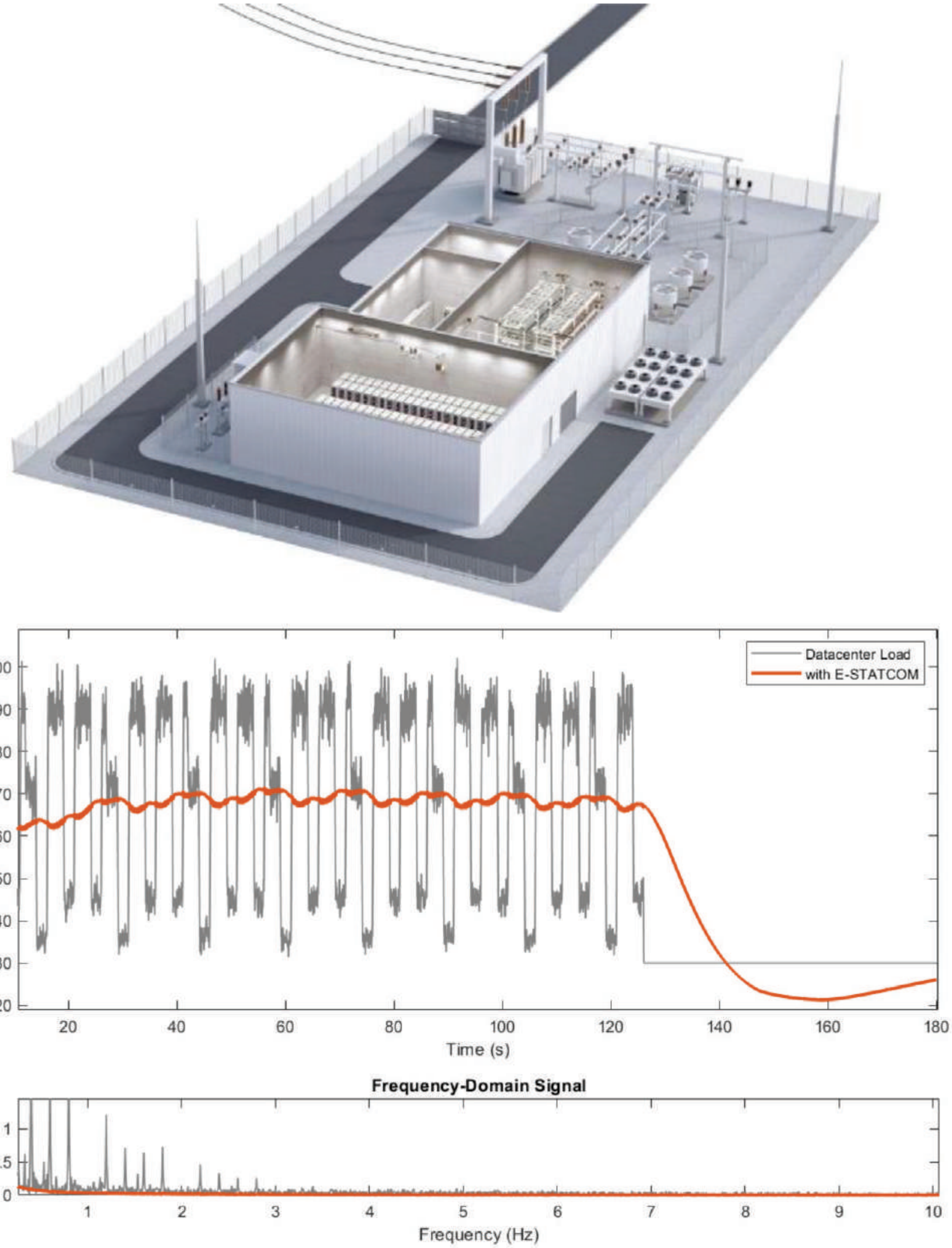
As discussed in Chapter 5, one of the most fundamental solutions to mitigate data center integration challenges is the development of clear, technically grounded interconnection requirements. These requirements help ensure that large load customers understand the performance expectations associated with connecting to the grid. By establishing obligations related to performance of the large load—power quality, voltage control, ramp rates, and disturbance ride-through, etc.—utilities can set a consistent baseline for system compatibility. Additionally, as detailed in Chapter 6, utilities should establish clear, consistent modeling requirements for large load interconnection studies. When these requirements are clearly communicated early in the planning process, data center developers can design their facilities to comply from the outset. This proactive alignment reduces the risk of costly redesign, delays, and operational issues during interconnection. Refer to Chapters 5 and 6 and Appendix B for more details.

Grid Stability and Load Power Quality Solutions

FLEXIBLE AC TRANSMISSION SYSTEM (FACTS) DEVICES AND OTHER GRID SUPPORT DEVICES

Numerous FACTS devices and other grid support devices can support grid reliability and stability. These include static synchronous compensators (STATCOMs), static var compensators (SVCs), synchronous condensers, medium voltage or high voltage direct current (MVDC/HVDC), and others.

FIGURE 8.1. E-STATCOM Solution – SVC PLUS FS



The E-STATCOM is placed between the grid and the variable load and helps smooth out active power demands from fluctuating loads.

SOURCE: SIEMENS ENERGY.

Enhanced static synchronous compensators (E-STATCOMs) are an emerging solution to help stabilize power demands for highly variable loads like data centers. E-STATCOMs are placed between the grid (or generator) and the variable load and include an energy buffer with tuned controls that inject and consume energy for short periods of time. The E-STATCOM provides dynamic voltage control, and an additional active power energy buffer smooths the demands from the variable loads. Reactive power compensation and voltage control combined with active power smoothing helps minimize system oscillations, improve power quality, and support system stability. Figure 8.1 (p. 62) shows an example +/- 75 MW, +/- 75 MVAR E-STATCOM and an illustration of how the energy buffer smooths active power consumption at the load point of connection.

BATTERY ENERGY STORAGE SYSTEMS

BESS can also provide grid reliability and stability benefits, helping smooth variable demands from AI, provide on-site backup power solutions, and deliver other grid services benefits. BESS may be coupled with other on-site generation to provide off-grid solutions for large data center campuses, and the BESS may participate in electricity markets and provide grid services if regulatory and market rules allow for such participation. The BESS may enable valuable load flexibility and support broader grid stability. Examples may include [27]:

- Peak shaving by discharging the BESS during high-demand periods to reduce net system load. This lowers electricity costs during times of scarcity and lessens resource adequacy concerns.
- Fast-responding controls that smooth power demand variability, particularly for AI data centers.
- Voltage ride-through support for nearby grid faults or other severe disturbances.

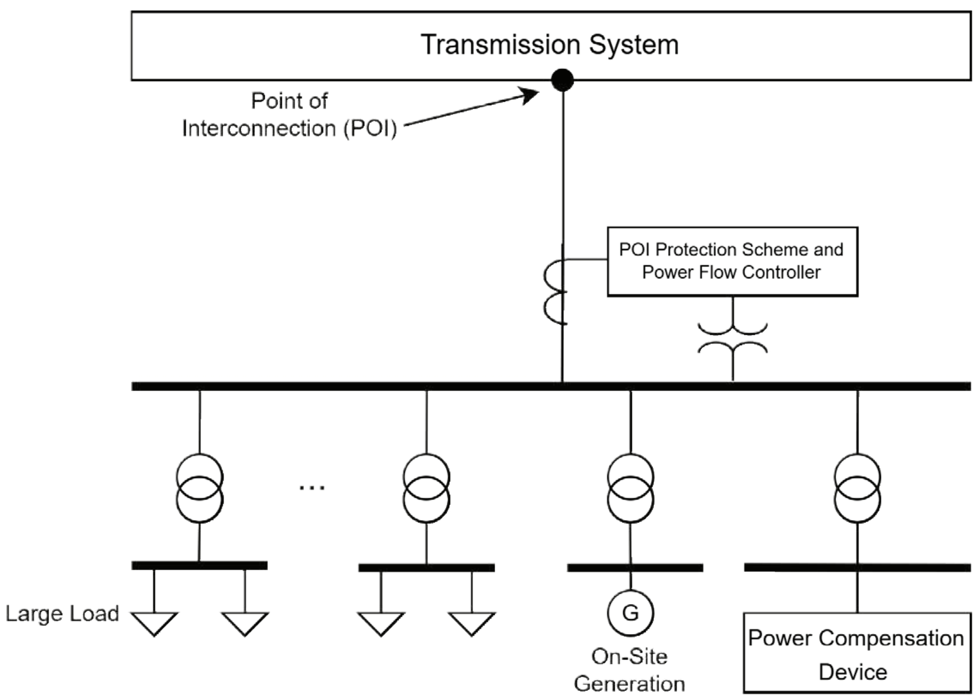
PHOTO: SMA.

- Grid forming (GFM) BESS that stabilize network stability, improve grid strength, and provide grid services that enable more widespread adoption of other IBRs across the system [28]. This can be advantageous in areas of the grid with limited or no synchronous generation nearby.
- Participation in ancillary service markets such as primary frequency response or fast frequency response and improved power quality.

PROTECTION SYSTEM COORDINATION AND ISOLATION SCHEMES

Large generation or load losses can affect adjacent turbine-generators or inverter-based resources, as well as causing large swings on the grid. Co-located load and generation facilities can design protection schemes to avoid large imbalances in generation and load at the point of connection to the grid and also protect their own infrastructure. These schemes may include rapid disconnection or power reduction of the behind-the-meter resources and loads at the facility. This can help avoid thermal network overloads, and stabilize grid stability under (if communication-assisted protections are put in place). Protection schemes enable large loads to connect without introducing stability implications, further enabling a more rapid large load buildout [29].

FIGURE 8.2. **Illustration of POI Protection Scheme to Manage and Maintain Power Flow**



SOURCE: ELEVATE ENERGY CONSULTING.

Transmission Infrastructure Buildout Solutions

TRANSMISSION INFRASTRUCTURE SOLUTIONS

Building out the transmission system is a long-term strategy and national goal in addition to answering the short-term need to serve the large loads of today. Investments in new transmission lines, substations, and reinforcement projects ensure that capacity keeps pace with increasing demand. Long-term planning efforts should prioritize transmission corridors that serve high-growth areas with significant data center activity. Identifying effective strategies to develop large-scale transmission projects—while maintaining affordability and meeting permitting requirements—is a critical priority for the industry.

To help accelerate large load connection, industry can look at innovative ideas beyond conventional transmission infrastructure construction. Some examples include:

- **Hot Line Reconductoring:** Upgrading some transmission and distribution circuits can be completed without de-energizing them, which minimizes service disruptions while increasing capacity. This method is particularly beneficial in areas with high load growth where outages for traditional reconductoring would be rather impractical.
- **Advanced Conductor Technologies:** Reconductoring existing transmission lines with advanced conductors can be a fast, cost-effective way to expand grid capacity using existing rights-of-way. Often this solution has faster permitting and regulatory approvals and shorter construction times compared with conventional new line construction [30].
- **Tower Raising:** For thermally limited issues caused by ground clearance on sagging transmission lines, tower raising can be a viable solution to increase line capacity beyond existing facility ratings. This may be paired with advanced conductor technologies to further maximize existing right-of-way utilization [31].

GRID-ENHANCING TECHNOLOGIES AND OTHER ADVANCED TECHNOLOGIES

Numerous grid-enhancing technologies (GETs) and other advanced technologies can help alleviate grid impacts for new large loads. Some examples include:

- **Dynamic Line Rating:** Dynamic line rating allow utilities to adjust transmission capacity based on real-time conditions such as ambient temperature, wind speed, etc., which may unlock additional real-time transmission capacity.
- **Power Flow Controls:** Power flow controls may help optimize grid utilization, alleviating network constraints such as thermal overloads or voltage violations.
- **Transmission Optimization:** Transmission operators can leverage real-time data to maximize grid capacity by optimizing the transmission system network topology.

Deploying these advanced technologies can improve system utilization and flexibility, reduce network constraints and congestion in real-time, minimize the need for curtailment, and enable faster interconnection of large loads. A combination of these solutions can improve hosting capacity for large loads without requiring extensive new infrastructure.

Load Flexibility and Utility Service Solutions

LARGE LOAD CUSTOMER FLEXIBILITY OPTIONS

Data centers have the technical potential to act as flexible loads, offering value to the grid. In certain cases, this load flexibility could help mitigate peak demands and support grid stability. While several pilot projects and research efforts show promise, widespread deployment remains limited due to technical, economic, and regulatory barriers. Load flexibility can be achieved various ways, including:

- Load reduction such as workload shifting/rescheduling and cooling system control.
- Onsite generation or energy storage dispatch to offset net demand.
- Participation in demand response or controllable load programs.

Flexible load strategies are well-suited for non-critical IT workloads that can be deferred and rescheduled without impacting business operations. When deployed at scale, flexible data centers could support local grid congestion issues as well as regional resource adequacy needs, serving as controllable and dispatchable demand.

UTILITY FLEXIBILITY OPTIONS AND SERVICE OFFERINGS

Utilities are considering developing customized interconnection offerings to enable more rapid integration of large-scale loads such as data centers. Some examples include:

- **Firm vs. Interruptible Service:** Allows for defined curtailment rights in exchange for lower cost of service and possible far less network upgrade costs.
- **Peak Load Curtailment Agreements:** Incentivizes demand reduction during grid stress events through financial or reliability-based incentives.
- **Flexible Interconnection Frameworks:** May include phased load deployments as generation or transmission expansion occurs, mobile generation or other interim solutions, expedited permitting, etc.

These types of utility services seek to provide scalable and grid-friendly integration opportunities that balance speed of deployment with critical grid reliability needs. Embedding load flexibility into utility planning practices can help accommodate a more aggressive data center expansion plan while preserving reliability.

9

Key Considerations for State Regulatory Proceedings

The pressure that large loads place on the transmission system, grid reliability, and cost allocation frameworks are already an issue in many state Integrated Resource Planning (IRP) processes, which include assessments of loads, resources, and reserve margins. However, planning frameworks may not be keeping pace with the unique challenges presented by large load interconnections, presenting an opportunity for reform. Regulators should require utilities to study and report on the impacts of large load interconnection requests as part of their existing resource planning obligations. In particular, utilities should be responsible for assessing how these loads affect system performance, reliability, and fairness to existing customers—and for proposing any needed investments, upgrades, or programmatic responses to manage those impacts.

This chapter is intended to support state regulators, utilities, and intervenors engaged in resource planning proceedings, with relevant considerations that may extend to rate and depreciation proceedings. The guiding questions in Box 4 and Appendix C may help these parties identify the types of information and analyses the utility should incorporate into resource planning processes to ensure that reliability and reasonable rates are maintained across all customer classes. Appendix C provides a more extensive list of questions for state regulators and other stakeholders to use when overseeing IRPs.

The high technical and economic stakes at the heart of interconnection make these questions complex, and they are not intended for regulators to answer directly. Rather, regulators can use these questions as a rule framework to help utilities systematically assess and transparently report the impact of large load interconnections on transmission system reliability and costs. Utilities should have the analytical responsibility of providing this information and are best positioned to carry out the studies and report results as part of their IRPs or filings.

Regulatory Rule Framework Considerations

At a high level, regulatory rules should address the following concepts (example draft language included in italics for reference):

PHOTO: ISTOCKPHOTO/BRIAN BROWN

- **Purpose:** This rule ensures that electric utilities systematically assess and transparently report the impacts of large load interconnections on transmission system reliability, network upgrade needs, and cost allocation.
- **Data Disclosure and Characterization of Large Load Requests:** Ensuring utilities collect and disclose[11] information about large load interconnections to support meaningful planning analysis.

  Utilities shall identify and characterize anticipated or pending large load interconnection requests above [X MW] as part of their Integrated Resource Plan (IRP). For each request, utilities shall:

  - *Provide expected peak demand and load shape (hourly or sub-hourly where available).*
  - *Indicate the interconnection point (transmission or distribution).*
  - *Describe the customer class and load use case (e.g., data center, industrial, crypto).*
  - *Identify known or proposed timing for energization and ramp-up.*
  - *Report whether and how these loads are included in the base load forecast.*

11 Utilities may anonymize data but should preserve sufficient detail to support planning analyses.

- **Transmission and Reliability Impact Assessments:** Ensuring that utilities study the impacts of large loads on system performance, capacity, and reliability using appropriate modeling methods.

  Utilities shall conduct transmission system impact assessments for each large load interconnection request, including:

  - *Power flow, stability, and contingency analysis under peak and shoulder conditions.*
  - *Impacts on local and system-wide planning reserve margins.*
  - *Implications for transmission congestion and curtailment risk.*
  - *Evaluation of any required network upgrades to maintain NERC-compliant reliability.*

  The utility shall summarize these results in the IRP and discuss mitigation measures or proposed investments.

- **Economic impact and cost allocation analyses:** Ensuring the cost impacts of large load interconnections are not unfairly shifted to existing customers.

  Utilities shall analyze and disclose the cost impacts of large load interconnections, including:

  - *Identification of direct and indirect costs (e.g., network upgrades, capacity procurement).*
  - *Proposed mechanisms for allocating those costs (e.g., direct assignment vs. socialization).*
  - *Analysis of rate impacts for existing customers under different cost recovery scenarios.*

  The utility shall propose just and reasonable cost allocation methodologies consistent with state and federal ratemaking principles.

- **Planning Integration and Investment Response:** Ensuring utilities incorporate study results into their actionable plans, budgets, and investment priorities.

  Based on reliability and economic analyses above, utilities shall propose any necessary:

  - *Transmission or distribution investments.*
  - *Demand response or non-wires alternatives.*
  - *Resource adequacy additions.*
  - *Revisions to interconnection study processes or thresholds.*

  These proposals shall be clearly linked to the identified large load interconnection impacts and included in the utility's IRP action plan or preferred portfolio.

- **Reporting, accountability, and continuous improvement:** Institutionalizing regular updates and adaptive improvement of planning rules.

  Each utility shall file an annual or biennial update on large load interconnections, including:

  - *New or withdrawn interconnection requests.*
  - *Updated load characterizations and timing.*
  - *Adjustments to system impact or cost allocation analysis.*
  - *Progress on any infrastructure investments proposed in previous IRPs.*

  Additionally, every [X] years, each utility shall propose improvements to this rule framework based on lessons learned and evolving system needs.

BOX 4

Questions for Regulators to Consier When Assessing Whether Utility Proposals to Serve Large Loads are Just and Reasonable

Grid Reliability and System Planning

- How does the proposed large load impact local and regional reliability, including contingency planning and system stress scenarios?
- Are existing transmission and distribution infrastructure upgrades needed, and who bears the cost?
- What are the risks of large load concentrations creating localized voltage stability or congestion issues?
- How will the seasonal and daily load shape of the large load impact resource adequacy, peak demand, and capacity planning for the larger network?
- Does the utility have sufficient generation capacity to meet the demand without triggering excessive reliance on emergency generation or imports?

Cost Allocation and Consumer Protection

- Who is paying for the interconnection and transmission upgrades, and how are costs allocated between the requesting customer, existing ratepayers, and utility shareholders?
- Are interconnection applicants being asked to make appropriate financial commitments, such as deposits or guarantees, to prevent speculative projects? [32], [33]
- Does the interconnection process prioritize the public interest, ensuring that large commercial loads do not unfairly shift costs onto existing residential and small business customers?
- Are cost-recovery mechanisms transparent, and do they align with regulatory principles of fairness?
- What happens if the large load (e.g., a data center) ceases operations prematurely? Will existing customers be left with the cost of underutilized infrastructure?

Prioritization

- What controls or processes do you have in place to ensure that all customers are treated fairly with respect to study and construction timelines?
- How does the utility or grid operator ensure transparency in interconnection studies and approvals for large loads?
- Are interconnection requests first-come, first-served, or are they prioritized based on economic benefits, reliability needs, or emissions reduction goals?

Stakeholder Engagement

- Is there a neutral third-party evaluation of the interconnection's impacts to ensure objectivity and protect public interest?

Demand Flexibility

- Can the large load be curtailed or shifted during peak demand periods to avoid unnecessary capacity expansions?
- Has the utility considered whether it is in the public interest to require contractual provisions that allow for interruptible service, pricing incentives, or time-of-use (TOU) rates to shape demand?

10

Potential Federal Actions to Address Large Load Risks

The Federal Power Act (FPA) established the legal framework for regulation of electricity in the United States. The Energy Policy Act of 2005 added Section 215 to the FPA, calling for the creation and certification of an Electric Reliability Organization (ERO) as directed by FERC [34]. Since 2006, NERC has fulfilled the role of the ERO, and NERC and its six Regional Entities comprise the ERO Enterprise.

NERC establishes and enforces Reliability Standards for the bulk power system, subject to FERC's review and approval [17]. The ERO Enterprise assesses, investigates, and audits Registered Entities to measure compliance with the Reliability Standards, and can also impose penalties for violations of the Reliability Standards through its compliance and enforcement division [35]. Section 215 applies specifically to the bulk power system and excludes local distribution facilities. The activities of NERC (and NERC members) are governed by the NERC Rules of Procedure [36].

The Rules of Procedure state that "each bulk power system owner, operator, and user shall comply with all Rules of Procedure of NERC that are made applicable to such entities by approval pursuant to applicable legislation or regulation" [36]. Hence, NERC has an Organization Registration program that identifies and registers bulk power system users, owners, and operators "who are responsible for performing specified reliability functions to which requirements of mandatory NERC Reliability Standards are applicable" [37]. The standards also use defined terms and acronyms defined in the NERC Glossary of Terms Used in NERC Reliability Standards [38].

The NERC Compliance Registry includes fourteen (14) entity types that are subject to applicable NERC Reliability Standards:

- Balancing Authority
- Distribution Provider
- Generator Owner
- Generator Operator
- Planning Coordinator
- Reliability Coordinator
- Resource Planner
- Reserve Sharing Group
- Frequency Response Sharing Group
- Regulation Reserve Sharing Group
- Transmission Owner
- Transmission Operator
- Transmission Planner
- Transmission Service Provider

There presently is no defined NERC registration classification for large load customers. Large loads connected directly to the bulk power system or connected indirectly through distribution circuits (even if dedicated connections) are not subject to any applicable NERC Reliability Standards. Thus, there are no federal reliability-based regulations imposed on large loads to support bulk power system reliability, resilience, and security.

Historically, this may have sufficed as individual large loads were unique in nature and typically not a significant size. However, with the changing nature of large loads, it may be suitable for federal regulators to set clear, effective, just, and nondiscriminatory requirements on large load customers through applicability of the NERC Reliability Standards.

Table 10.1 (p. 73) summarizes the NERC Reliability Standards that could apply to NERC-registered large load entities connecting to the BPS [17].

TABLE 10.1. **Review of NERC Reliability Standards and Potential Applicability to Large Loads**

Standard	Standard Title
CIP-002-7	Cyber Security — BES Cyber System Categorization
CIP-003-10	Cyber Security — Security Management Controls
CIP-004-8	Cyber Security — Personnel & Training
CIP-005-8	Cyber Security — Electronic Security Perimeter(s)
CIP-006-7	Cyber Security — Physical Security of BES Cyber Systems
CIP-007-7	Cyber Security — System Security Management
CIP-008-7	Cyber Security — Incident Reporting and Response Planning
CIP-009-7	Cyber Security — Recovery Plans for BES Cyber Systems
CIP-010-5	Cyber Security — Configuration Change Management and Vulnerability Assessments
CIP-011-4	Cyber Security — Information Protection
CIP-012-2	Cyber Security – Communications between Control Centers
CIP-013-3	Cyber Security – Supply Chain Risk Management
CIP-015-1	Cyber Security – Internal Network Security Monitoring
COM-001-3	Communications
COM-002-4	Operating Personnel Communications Protocols
EOP-012-2	Extreme Cold Weather Preparedness and Operations
FAC-001-4	Facility Interconnection Requirements
FAC-002-4	Facility Interconnection Studies
FAC-008-5	Facility Ratings
IRO-001-4	Reliability Coordination - Responsibilities
IRO-010-5	Reliability Coordinator Data and information Specification and Collection
MOD-032-1	Data for Power System Modeling and Analysis
PER-006-1	Specific Training for Personnel
PRC-004-6	Protection System Misoperation Identification and Correction
PRC-005-6	Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance
PRC-012-2	Remedial Action Schemes
PRC-017-1	Remedial Action Scheme Maintenance and Testing
PRC-019-2	Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection
PRC-027-1	Coordination of Protection Systems for Performance During Faults
PRC-028-1	Disturbance Monitoring and Reporting Requirements for Inverter-Based Resources (*only IBRs)
PRC-029-1	Frequency and Voltage Ride-through Requirements for Inverter-based Resources (*only IBRs)
PRC-030-1	Unexpected Inverter-Based Resource Event Mitigation (*only IBRs)
TOP-001-6	Transmission Operations
TOP-003-7	Transmission Operator and Balancing Authority Data and Information Specification and Collection
VAR-002-4.1	Generator Operation for Maintaining Network Voltage Schedules

SOURCE: ELEVATE ENERGY CONSULTING.

APPENDIX A
Large Load Data Submittals

It is important to gather sufficient information from large load customers, particularly data center customers, that provides the utility with sufficient information to conduct reliability studies and assessments of grid impacts.

This appendix outlines fundamental information utilities should request from data center developers for new delivery points. The same types of information can be adapted for modification of existing delivery points. The information is based on various utility large load interconnection forms, applications, and requirements [39], [40], [5], [41].

Customer Information

Company name	
Current customer?	
Company address	
Company point of contact (POC) name	
Company POC phone number	
Company POC email	
Company POC fax number	

Readiness Information

Site control obtained?	
If no, what are the plans to obtain site control?	
If yes, what is the name, address, and contact information for property owner of record?	
Financial institution name, address, and contact information	
Property owner signature	
Financial institutions signature	

Load Interconnection Request Information

New load interconnection request or modification to existing request?	
Load address or GPS coordinates	
Load delivery point to transmission/distribution system	
Description of load connection to electric grid	
Prefer overhead or underground service?	
Delivery point nominal voltage level	
Seasonal Peak MVA Transmission Service Request	
Description of inter-hourly, hourly, daily, seasonal, and annual load characteristics including peak MVA demand, load profile, etc.	
Expected load capacity factor (annual % of peak demand) and calculation of capacity factor	
Expected demand ramp-up (phase-in) including month and year, and peak demand requested	
Description of power requirements at startup (i.e., commissioning, testing, etc.)	
Description of reliability or redundancy requirement (i.e., dual feeds, redundant systems, coordination with UPS, etc.)	

Interconnection Request Timeline

Requested load energization date	
Expected date for load customer construction to start	
Expected date for load customer construction to be complete	
Requested date for utility construction to commence	
Requested data for utility construction to be completed	
Other related engineering, procurement, or construction milestones	

Load Substation Transformer Information

Transformer primary voltage	
Transformer secondary voltage	
Transformer nameplate capacity (MVA)	
Transformer impedance (R/X/B) and base values	
Transformer tap ranges	
Transformer tap position	
Fixed or under-load tap changing	
Transformer connection (e.g., wye-wye, delta-wye, etc.)	
Transformer make and model	

Load Composition Information

Load Type	Spring Day (50–70 ˚F)	Summer Peak (100–115 ˚F)	Winter Peak (0–30 ˚F)
Motor A: % of total load consisting of 3-phase induction motors used in industrial air conditioning compressors or refrigeration systems (e.g., large building central air cooling)[a]			
Power Electronic Motor A: % of Motor A load comprised of electronically-interfaced motor loads such as variable frequency drives (VFDs)[b]			
Motor B: % of total load consisting of 3-phase induction motors used in commercial ventilation fans and air handler systems[a]			
Power Electronic Motor B: % of Motor B load comprised of electronically-interfaced motor loads such as VFDs[b]			
Motor C: % of total load consisting of 3-phase induction motors used in water circulation pumps in cooling systems.[a]			
Power Electronic Motor C: % of Motor C load comprised of electronically-interfaced motor loads such as VFDs[b]			
Motor D: % of total load consisting of single-phase air conditioning loads (most commonly found in residential A/C units, not commercial)[a]			
Power Electronic Load: % of total load consisting of power electronic devices/converters such as servers, high-efficiency appliances, consumer electronics, computers, etc.[a]			
Static/Other: % of total load remaining consisting of other loads such as lighting, cooking, small water heaters, etc.[a]			
Equivalent impedance (R and X) between customer delivery point and end-use loads (i.e., tie lines, transformers, substation delivery equipment, etc.) with description impedance base values and how this impedance was derived.			

a Total % of load should sum to 100%; otherwise, an explanation shall be provided.

b These %'s should be a percentage of the reported value preceding this cell. For example, if Motor A load is 10% of the load yet if it is all connected via VFD, then the subsequent cell should state 100% (not 10%).

Load Reconnection Information

Manual or automatic reconnection to grid? (Explain characteristics)	
Immediate reconnection or delayed reconnection? (Explain process)	
Time to reconnect, if automatic (seconds)	
Reconnection frequency and voltage settings (thresholds, deadband, duration), hysteresis curve, etc.	
Reconnection ramp rate and ramp rate limit (% of total load/min)	
Description of reconnection process and time (stages, specific loads, etc.)	

Load Backup Power and UPS Information

Total backup (emergency) generation capacity (MVA)	
Backup generation fuel type	
Backup generation duration (based on typical access to fuel/energy)	
Total discharge capacity of backup battery energy storage systems (BESS) (MVA)	
% of digital load processes shifted to redundant locations off-site	
Time duration for load transfers to occur	
UPS voltage sag threshold and duration curve for disconnection (list of trip values and durations)	
UPS voltage swell threshold and duration curve for disconnection (list of trip values and durations)	
Description of measurement quantities used for voltage sag and swell measurements (location(s) at site, per-phase or 3-phase, RMS filtered quantity or instantaneous point of wave measurement, etc.)	
UPS high and low frequency threshold and duration curve for disconnection (list of trip values and durations)	

Load Operational Performance Information

Load power factor range (lead/lag)	
Description of load cycling performance (random, price-sensitive, hourly, daily, seasonal, etc.)	
Maximum ramp limits (% of total load/min)[a]	
Narrative describing the frequency or variability of expected load ramping	
Power quality issues or concerns that affect system performance (e.g., large motor loads starting, power factor, total harmonic distortion, chopped waveform loads, planned capacitors and filters, etc.)	

a If the load is expected to ramp or cycle within a minute (i.e., seconds or less), this information should be provided separately with a description of the load ramping, oscillation, and/or cycling characteristics—magnitude, duration, frequency, etc.

Grid-Connected Generation

Total capacity of customer generation that connects and interacts with the grid (MVA) (additional generation information will be required)	
Operational characteristics of generation behavior when connected to the grid such as participation in wholesale electricity market, ancillary services, charging/discharging patterns, demand-side management, etc.	

Interconnection Request Documentation

Site Plan, Layout, and Electrical Design	
Site plan including layout, substation configuration, access roads, and equipment	
Electrical single line diagram including layout and configuration of customer electrical equipment	
Site Electrical Protection Design	
Electrical protection and control design functional diagrams including protection system equipment (make and model), protective functions enabled, and protection settings for each protection	
Transformer nameplate ratings, test reports, specification sheets, and saturation curves	
Site Electrical Controls	
Electrical operating procedures and operational characteristics description	
Control narrative explaining any applicable load control set points, operating characteristics, etc.	
Ride-Through Performance	
All UPS protection and control settings, including voltage and frequency disconnect and reconnect measurements and settings	
Load site voltage and frequency ride-through capability curve and a description of how the curve was derived	
Number of successive faults and the duration of faults the load can successfully ride-through including a description of how this information was derived	
Modeling Information	
Positive sequence dynamic model using the composite load model (or other utility-accepted dynamic model(s))	
Positive sequence user-defined dynamic model, when requested by utility	
Electromagnetic transient (EMT) model	
Short-circuit model	
Harmonics model or information, if required	
Control block diagrams, control narratives, model documentation, and technical justification narrative of model development	

APPENDIX B
Technical Requirements for Large Loads

This appendix provides additional details and insights regarding some of the technical requirements outlined in Chapter 5.

Load Interconnection Size Limits

Loss of a single end-use load has not historically had a significant reliability risk to the BPS, and large load customers often have sought multiple service connection points to improve reliability of service. However, with ever-increasing load interconnection request sizes, single load connection points may pose reliability risks to the local or interconnected grid. The ability to transfer digital services across loads (e.g., cloud data center resilience) may reduce the need for customers to seek additional service points.

Thus, transmission providers should consider the loss of single large load customers, loss of credible multiple load connection points, and the aggregate loss of large load customers due to common grid events in reliability studies. In some cases, it may be prudent to establish load interconnection limits at a single point of interconnection to minimize risk. Large load customers can connect larger loads to the system; however, they would require multiple service points. Above a certain size threshold, service points may need to be from different transmission substations to avoid risks of loss of a substation.[12]

ERCOT has proposed such limits due to concerns with grid frequency and voltage control for inadvertent tripping of large loads. Dominion Energy also limits the number of direct-connect loads (tapped facilities) on transmission lines to four and relies on engineering judgment in applying this criterion. Dominion also limits the amount of direct-connect load at any substation to 300 MW for reliability reasons [5].

12 This is a credible contingency studied as part of NERC CIP-014 risk assessments: https://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-014-3.pdf

Model Sharing

Each transmission provider should specify modeling requirements for large load customers that span the different types of simulation domains used to conduct reliability studies. Types of models may include:

- Powerflow model and/or information.
- Phasor domain transient (PDT)[13] dynamic model.
- Electromagnetic transient (EMT) model.
- Short-circuit model.

Each transmission provider should specify the format and level of detail for each model type and specify the corresponding documentation (model structure and block diagrams, controls narrative, load composition breakdown, etc.) that must accompany the model submission. Given the depth and complexity of some of these studies, these types of requirements must be rather detailed. The transmission planner and large load customer can work collaboratively through the study, and the requirements should be defined clearly to help facilitate effective collaboration.

The transmission provider should determine if standard library models are sufficient or if detailed user-defined models are needed, where applicable. The dynamic models should also be accompanied by a controls narrative, and electrical protection systems should be represented in each model, where applicable.

Data Recording and Monitoring Requirements

Each transmission provider should specify data recording requirements for large load customers. This data is used for monitoring the performance of large loads during grid events, conducting model validation, and forensic event analysis. Examples of measurements include:

- **SCADA Telemetry:** Data within the customer substation—whether utility- or customer-owned—capturing the status of all breakers, switches, and electrical devices, as well as voltage, current, and power quantities throughout the station.
- **Sequence of Events Recording (SER):** Recording enabled in all protective relays and other similar devices capturing the status and cause of change for any devices within the facility—breakers, reactive devices, switches, transformers, auxiliary loads, etc.
- **Digital Fault Recording (DFR):** Data about the main connections between the load customer and the utility including triggered, high-speed, point-on-wave measurements voltage, current, frequency, and active and reactive power.

13 i.e., fundamental frequency positive sequence dynamic simulation models such as PSLF, PSS®E, etc.

- **Dynamic Disturbance Recording (DDR):** A continuous recording device (e.g., a phasor measurement unit) capturing positive sequence voltage and current phasors, frequency, active power, and reactive power at the connections between the load customer and the utility. This functionality can be integrated into most modern microprocessor-based relays.
- **Power Quality Monitoring:** Power quality indicators to ensure compliance with the utility's power quality standards and to support forensic event analysis.

Voltage Ride-Through Requirements

Each transmission provider should establish voltage ride-through requirements that define the range of voltages for which the large load must remain connected to the BPS. Without some degree of ride-through capability, large loads could unexpectedly or abnormally trip or disconnect from the system for normal grid faults. As illustrated in Chapter 2, unexpected disconnection from the grid due to normal grid faults can cause severe performance issues to the grid that can result in instability, uncontrolled separation, or cascading outages.

Voltage ride-through requirements should strike a balance that considers the following:

- Normal clearing time of transmission and/or sub-transmission system protective relaying.
- Large load facility design (end-use component capabilities, PDU and UPS ride-through settings and capabilities, etc.).
- Generator ride-through capability curves.
- Latest versions of NERC PRC-024 and NERC PRC-029 [17] and international requirements [18].
- IEEE 2800-2022 Clause 7 ride-through requirements [42].

While there may be some additional costs to ensuring ride-through performance, these pale in comparison to the costs associated with system-wide network upgrades to minimize voltage drop during and immediately following grid fault events (e.g., STATCOMs, synchronous condensers, and transmission infrastructure). This is an inevitable situation due to the physics of the electric power system. Grid planners and operators cannot expect to lose unknown and potentially significant amounts of power every time a fault occurs.

Large load customers can design their equipment, protection systems, and controls to reasonably accommodate the need for some degree of ride-through performance. However, excessively wide ride-through performance curves should not be unnecessarily introduced to avoid costly solution options.

Frequency Ride-Through Requirements

Each transmission provider should also establish frequency ride-through requirements that define the range of frequencies for which the large load must remain connected to the BPS. Again, abnormal or unexpected disconnection of large loads during abnormal frequency events could further exacerbate grid reliability risks. This is particularly a concern during overfrequency conditions where excess generation versus load is driving frequency high. Additional load tripping would further drive frequency upward and could disconnect additional loads, resulting in cascading outages and widespread system instability.

While frequency disconnection is less of a concern and risk for large loads, particularly in large, interconnected bulk power systems, it is still important to establish a performance basis to be able to effectively plan and operate the system. These requirements will often get programmed into protective relaying at the site and are used as a basis for designing other protection systems within the facility.

Utilities establishing frequency ride-through requirements for large loads should consider requirements for generation assets such as NERC PRC-024, NERC PRC-029, and IEEE 2800-2022, along with reasonable equipment capabilities for large load facilities.

Power Factor / Reactive Power Requirements

Each transmission provider should establish power factor requirements that ensure large load facilities are designed and operated to maintain steady-state reactive power limits within a defined range of consumption (or production). For example, large loads may be required to remain within ± 0.95 power factor within the normal operating range around nominal voltage schedule. For a 1,000 MW data center, this would equate to consuming upwards of 330 MVAR reactive power from the system. Thus, for very large loads, tighter power factor limits may be required.

Large load customers unable to meet these requirements may be required to install supplemental reactive power devices to keep reactive power within defined limits. Depending on the reactive power profile of the load, this may require shunt capacitors/reactors for slowly varying changes or dynamic reactive devices such as STATCOMs for variable or sporadic changes in reactive power.

Power Quality Requirements

Each transmission provider should establish power quality requirements to prevent equipment damage for both the utility and customer infrastructure, ensure high quality of service, and avoid instability and harmonics issues. Power quality requirements may include the following:

- **Acceptable Voltage Range:** The large load facility shall not cause voltages to exceed acceptable ranges, in accordance with utility practices and/or applicable standards (e.g., ANSI C84.1 [43]).
- **Harmonics:** The large load facility shall not contribute total harmonic distortion (THD) at its point of interconnection (POI) beyond the limits specified in IEEE Standard 519 or its successor [44]. Individual harmonic components may be specified and shall be operated within.
- **Flicker:** The large load facility shall not cause voltage flicker to exceed defined permissible levels and must align with IEEE Standard 1453 [45]. Flicker events shall not cause undue interference to other customers or compromise utility operations.

14 Note that forced oscillations can occur at the generation, transmission, or distribution level and interact with the larger grid.

- **Imbalance:** The large load facility shall maintain balanced load across all electrical phases to limit voltage unbalance at the POI to less than defined limits and/or applicable standards (e.g., IEC 61000-3-13 [46]).
- **Transients and Surges:** Equipment installed at the large load facility shall not introduce transients or surges that negatively impact the utility infrastructure or operations; protection and mitigation measures such as filters or surge suppressors may be required.

Large load customers are required to perform compliance testing for power quality and submit periodic reports to verify ongoing compliance. Acceptable testing methods are outlined in IEEE, IEC, or other relevant standards. Failure to comply with power quality requirements may result in disconnecting the facility from the utility system until it complies.

Oscillation Damping Requirements

Each transmission provider should establish oscillation damping requirements to ensure that large loads are contributing positive damping to the bulk power system and are not inadvertently causing forced oscillations, particularly those that can interact with local or system modes. Equipment and processes within the large load facility (e.g., motors, drive, power electronics, digital processes) may seek to operate on a cyclic or repetitive oscillatory basis, and these types of behaviors can have adverse impacts on the local and large interconnected grid. The large load facility shall not introduce or amplify oscillations at synchronous, subsynchronous, or supersynchronous frequencies.

Oscillatory behavior of the large load facility (i.e., ramps up and down on a cyclical basis) can interact with the natural system modes (i.e., inter-area modes) which can amplify the forced oscillation across the entire interconnected system. These types of forced oscillations should be carefully studied and avoided. An example of this occurred at a generation[14] facility in Florida in 2019, where a measurement error resulted in cyclical oscillations in the plant at about a 4-second periodicity (i.e., 0.25 Hz frequency). This coincides with one of the natural system modes and resulted in the entire Eastern Interconnection experiencing multi-hundred MW swings for 18 minutes, until the plant was disconnected. Upon further investigation, the facility experienced damage that required significant repairs and maintenance before bringing the unit back online [6].

Additionally, if the large load facility is being connected near other large power electronic devices or transmission network series compensation, this could introduce SSO risks. These conditions require EMT simulations to ensure that subsynchronous interactions (SSI) will not occur. This requires accurate and careful modeling of the large load facility, the surrounding transmission network, and any nearby generation and loads.

These types of oscillations, depending on the nature and cause of the oscillation, can occur very quickly and unexpectedly. Therefore, it is important to study them ahead of real-time operation and to have adequate monitoring equipment to detect and mitigate them, if possible. This may require immediate operational actions to address the oscillation as well as forensic event analysis and information sharing between parties to make any design, protection and control, or operational adjustments.

Short-Circuit and Protection Requirements

Each transmission provider should establish minimum and maximum short-circuit current levels at the customer interface to ensure customer equipment is rated appropriately. This is particularly relevant in situations where the large load facility may have grid-paralleled generation that can notably affect short-circuit levels. The load customer (or co-located generator customer) may be responsible for mitigation measures regarding excess fault current levels.

Load customer protection schemes will also need to be coordinated with the utility protection system philosophy. These utility protection philosophies can vary widely, and the industry would benefit from aligning on common or best practices. Regardless, the following are a few areas where careful coordination is necessary:

- Using utility-defined protection schemes, equipment, and/or settings for the direct connection facilities in which the load customer is connecting to the larger grid.
- Ensuring that facility-level protections and settings are provided to the utility to ensure that grid faults do not cause any misoperation or adverse impacts system-wide. Coordination should cover UPS/rack-level protection for data centers, ensuring alignment with utility systems.
    - In the Northern Virginia event described in Chapter 1, data center protection settings were not properly coordinated with utility reclosing schemes; thus, widespread data center tripping occurred for what the utility considered “normal operation.”
- If backup generation operates in parallel with the grid, studies must evaluate fault contributions, breaker duty impacts, and coordination with system protection schemes.

Data Sharing

Each transmission provider should establish data sharing requirements that ensure large load customers provide the transmission providers with all relevant operational and planning data for each large load facility to support system modeling, reliability assessments, engineering evaluation, protection coordination, and real-time operations. Examples of such data include:

- Load forecasts, including both short-term (days and weeks ahead) and long-term (load growth over months and years).
- Equipment specifications, ratings, and nameplate diagrams.
- Protection and control schematics and settings relevant to utilities interconnection requirements.
- Real-time telemetry (SCADA) for operational data exchange.
- Event monitoring data and logs following grid disturbances, trips, and other major types of facility operations.
- Backup generation information, including details on capacity, operational modes, protection schemes, interconnection status, and designs that adhere to utility back-up generation requirements.
- Demand response capabilities and real-time status.

- Outage and maintenance activities (both planned and unplanned) and corresponding impacts to facility load forecasts.

All data submissions by large load customers must adhere to utility-defined formats and update frequencies.

Given the sensitive and competitive nature of large load facility information, utilities may also want to establish non-disclosure agreements (NDAs) or similar contracts to ensure both the utility data and large load customer data are fully protected. One enhancement to these contracts could include specific language that prohibits either party from selling, sharing, or disclosing any shared/submitted information.

Operational Control and Communications Requirements

Each transmission provider should establish requirements for real-time operation and communication for large load customers. Large load facilities must operate in compliance with utility-defined operational reliability criteria. This may include ramp rate limits, real-time dispatchability, voltage/reactive power support, and ride-through capabilities. Automated and manual controls should be in place to respond to utility directives during normal operations and emergency conditions.

Transmission providers must set requirements for secure, reliable communication channels between large load customers and utilities to enable real-time monitoring, coordination, and emergency response. Communication protocols should align with industry standards (e.g., IEEE, IEC 61850, NERC CIP) and support SCADA integration, event reporting, and 24/7 availability of key personnel.

In addition, specific types of operational notifications by the large load to the utility should be put into the transmission providers requirements. These may include:

- Energization notifications and communications.
- Interim operations notification when the large load is only operating for a defined period of time (e.g., not continuous operations).
- Emergency operational conditions at the large load facility.
- SCADA and other real-time control status, including failures and communications outages.
- Limited operations notification when outages, maintenance, equipment failure, or other incidents at the large load facility occur that impact the load level of the facility or the grid interconnection.

Emergency Response and Coordination

Each transmission provider should establish requirements for large loads to develop, maintain, and share an emergency response plan that outlines contingency actions, communication protocols, and coordination with the utility during equipment failures, blackouts, frequency/voltage excursions, cyber incidents, natural disasters, or other major types of incidents. The emergency response plan should also include designated personnel that must be available for emergency coordination and drills with the utility, as required. Emergency response plans must also include backup generation details and conditions when they would be in operation, all of which must adhere to the transmission provider's backup and parallel generation requirements. Facilities with backup generation or islanding capabilities must follow approved procedures for safe transitions, as defined by the transmission provider and relevant industry standards.

Emergency response plans must be shared with the transmission provider upon any updates to the plan. Key information to be shared with the utility includes:

- Key personal contact information for the utility, including 24/7 Emergency Hotline, local facility operation center, local onsite staff, dedicated account representative, dedicated grid/electrical engineer for the facility, on-site technicians, on-site security, and facility manager.
- Initial notification procedures.
- On-going update procedures as emergencies progress in time.
- Post-emergency review process between large load and transmission provider.

Operations and Maintenance Requirements

Each transmission provider should establish requirements for large load customers to maintain their facility's electrical infrastructure, protection systems, and control equipment per utility and industry standards. These requirements should include communication and coordination of scheduled maintenance; large load customers should be required to immediately report emergency maintenance or operational outages to their transmission provider. Compliance with utility inspection, testing, and reporting requirements should be mandatory and defined in the requirements.

Transmission providers should clearly define ownership and maintenance responsibilities for all grid-connected equipment. Maintenance schedules should be set in accordance with equipment manufacturer recommendations and coordinate these schedules far in advance so that planned outages and other maintenance events do not affect grid reliability. Requirements can also set the expectation for quick communication and coordination between the two parties regarding any urgent or unplanned maintenance that may be required over the life of the facility.

Demand Response Requirements

Each transmission provider should require any large load facility that is participating in demand response programs to share all relevant demand response details and to comply with demand response dispatch signals, response times, and performance verification criteria. Important requirements include:

- Coordination of load curtailment or shifting to minimize adverse grid impacts while aligning with market and reliability requirements.
- Utility audits of load demand response capabilities and performance over time.

- Definitions for all monitoring data and other information necessary to evaluate the demand response of the facility over time.

Utility Right to Monitor and Enforce Requirements

Each transmission provider should have the right to monitor and enforce compliance with the requirements outlined for large load customers to maintain the safety, reliability, and quality of service across the electric system. Specific rights include:

- **Monitoring and Data Access:** The transmission provider has the right to monitor the performance and operational characteristics of the large load facility at the point of interconnection. The large load customer shall provide the utility with access to relevant operational data, including but not limited to real-time measurements, event logs, protection and control settings, electrical equipment configuration and design, and any applicable compliance reports, upon request.
- **Site Inspections:** The transmission provider may conduct electrical site inspections of the large load facility to verify compliance with interconnection and operational requirements. The large load customer shall provide reasonable access to authorized utility personnel.
- **Compliance Verification:** The transmission provider should reserve the right to require the large load customer to perform tests and verification procedures to demonstrate compliance with other specified requirements. Such procedures may include, but are not limited to, desktop engineering analysis, harmonic measurement and analysis, load flow and dynamic studies, protection coordination assessments, and power quality assessments.
- **Corrective Actions:** If the large load facility is non-compliant with any of the requirements, the transmission provider may issue a notice requiring corrective actions within a specified timeframe. The customer is responsible for implementing corrective measures at their own expense to restore compliance.
- **Disconnection Authority:** The utility reserves the right to temporarily or permanently disconnect the large load facility from the electric system if non-compliance with requirements poses a risk to system reliability, safety, or other customers; if the customer fails to implement corrective measures within the specified timeframe; or if emergency conditions arise that necessitate disconnection to protect the grid. Disconnection should be performed in accordance with the defined requirements and within applicable regulatory and contractual provisions.
- **Notification:** The utility should provide reasonable notice of any required monitoring, inspections, or enforcement actions, except in cases where immediate action is necessary to protect system reliability or public safety.

These types of provisions should be included in the contractual requirements between the transmission provider and the large load customer as a condition of interconnection and continued service, but may also be documented in the facility interconnection requirements.

APPENDIX C

Detailed List of Questions for State Regulators

As large loads become more common and impactful, utilities need clear, proactive plans to manage them. This chapter provides state regulators, utilities, and intervenors involved in planning, rate, or depreciation proceedings with questions to support rigor and accountability throughout the interconnection process. These questions help ensure that large load interconnections are reviewed fairly, that reliability risks are identified, that consumers are protected, and that costs and responsibilities are shared appropriately.

Protecting Existing Customers

- What measures are being taken to ensure that costs and risks associated with the interconnecting large load are not being passed onto existing customers?
- What financial safeguards are in place to ensure that debts or financial obligations do not adversely impact ratepayers?
- Will existing customers be subsidizing infrastructure investments or operational costs in any way? Why or why not? How is this guaranteed?
- What is the plan for dealing with stranded assets if large load customers do not materialize, suspend development, or operate for a shorter duration than the generator assets?
- What contingency plans are in place to ensure that unrealized demand (e.g., from abandoned projects or loads that demand less energy than projected) does not adversely affect existing customers?
- How is the utility assuring that large load customers will remain in the region long term?
- Are existing customers adequately represented and educated on the benefits and risks presented by large load customers? Is the commission ensuring that ratepayers and stakeholders have opportunities for informed input into current and future decisions?
- How are existing customers and ratepayers being protected from higher energy costs and prices given the large increase and demand and incremental generation costs?

- What are the projected economic benefits (e.g., construction job creation, permanent job creation, tax revenue) of this project?

Jurisdictional and/or Legal Issues

- Do the proposals or plans for large load interconnection seek or require changes to the existing regulatory process? What are the primary drivers or reasons for such changes?
- What specific regulatory requirements are being avoided with such changes, and what measures are in place for oversite, where applicable?
- Does the proposed approach align with other utilities and states? If not, would the petition or proposal establish new precedents for avoiding any specific jurisdictional obligations?
- What impacts would this have on existing ratepayers?
- Does the petition or request align with broader state-level resource goals and goals of the broader electricity market?

Large Load Application Process

- What information is required for the initial large load interconnection request? Is the information adequate to assess the credibility, certainty, and readiness of the interconnection customer to seek transmission service?
- How does the transmission provider assess the adequacy and completeness of the information provided at the time of interconnection request to ensure that all models are provided and all technical requirements are met by the proposed facility?
- What financial commitments (i.e., deposits) are required for large load interconnection requests? Do those financial commitments escalate throughout the interconnection process?
- What site control requirements exist for large load interconnection requests, and are these considered as part of a “readiness” assessment?
- What technical and financial capabilities are required for an interconnection customer to be deemed a credible applicant? Is that criteria made public?
- How does the transmission provider ensure that this project is not being added to other interconnection queues in other regions around the region or country?

Large Load Interconnection Requirements

- Are the large loads connecting to the distribution system or transmission system? Who is the interconnecting entity?
- How are the distribution and transmission providers coordinating interconnection requirements to ensure alignment of transmission and distribution system reliability needs?
- Have the distribution and/or transmission provider established clear, effective, consistent interconnection requirements for large loads that include the key topics described in this paper?

- Do those requirements include data sharing, modeling, operational performance limitations (e.g., ramp rate limits), oscillations, ride-through performance, monitoring data, event analysis support, and the various other topics covered in this report?

Large Load Queue Management

- Does the utility have a dedicated queue process for large load interconnection requests?
- Is this queue process administered by the transmission or distribution organization (or department) or economic development department, and how are these organizations and departments collaborating with each other through the process?
- What type of queue process is used—serial, cluster, other? What is the reasoning for the type of queue process used?
- If using a serial queue process, what checks and balances are in place to ensure that load interconnection requests are processed in a timely manner and that speculative interconnection requests are removed from the queue without causing unnecessary backlogs or delays for other legitimate requests?
- Are there defined timelines for how long a large load interconnection request can remain in the queue before being removed?
- Are clear, explicit queue milestones, costs, and timelines established that hold the large load customer accountable to move the queue process along? Are the costs for queue application and milestone development high enough to discourage speculative projects?

Large Load Operational and Performance Considerations

- Does the transmission provider require the large load customer to provide some form of narrative or other data that explains how the large load facility will operate when connected to the bulk power system?
- Is the large load customer required to provide the following information to the transmission provider/transmission planner?
    - Facility electrical topology and single line diagram.
    - Protection and control systems throughout the facility and their associated settings.
    - Load voltage and frequency ride-through curves (threshold and duration).
    - Load variation narrative and explanation (frequency and magnitude of variations).
    - Expected ramp rates.
    - Restoration settings.
    - UPS protection and control settings.
    - Load composition information.
    - Auxiliary equipment capabilities, ratings, and protection settings.

- Explanation and technical details related to fast ramping and oscillatory behavior.
- Power quality impacts.
- Short-circuit levels.
- Backup generation and grid-paralleled generation information.
- Transformer and other equipment ratings, documentation, etc.

Load Forecasting

- Is there a defined or formalized methodology for determining when large load interconnection requests enter system demand forecasts and are subsequently included in integrated resource planning and other long-term transmission or resource procurement activities?
- What specific interconnection milestones (site control, financial, technical, etc.) must be met for considering large loads in models and studies?
- How are large loads differentiated from other demand growth projections?

Large Load Modeling

- Have large load modeling requirements been established by the transmission provider or transmission planner? Do they include production cost, steady-state powerflow, dynamic stability, EMT, and short-circuit models?
- Are these models required as part of the large load interconnection application? Or are they required at later stages throughout the interconnection study process? Are these milestones established and enforced?
- How are these models verified to be accurate representations of the equipment proposed?

Large Load Interconnection Studies

- What is the process and what are the milestones for initiating large load interconnection studies?
- Are any types of cursory or high-level analyses done prior to conducting a more comprehensive interconnection study? Why or why not?
- What type of large load studies are conducted for each interconnection request? Do they satisfy the study-specific questions detailed below?
- What criteria determine whether a type of study is required (e.g., interconnection request size)? Are these criteria codified, shared with applicants, and available publicly?
- What are the average costs of conducting large load interconnection studies?
- What mechanisms exist for recovering transmission system costs from large load interconnection customer requests? Are large load customers paying for studies performed by the transmission provider, whether qualitative or quantitative? If not, how are these costs covered by the utility?

- **Production Cost Analysis Studies:**
  - Are 8,760-hour studies being conducted to ensure that large loads can be met at all hours of the day given the projected resource mix proposed by the utility?
  - Are large load demand profiles (daily, seasonal, price-sensitive, and other variabilities) documented, well-understood by the utility, and modeled appropriately?
- **Powerflow and Contingency Analysis Studies:**
  - Which powerflow base cases are used to conduct steady-state thermal and voltage violation analysis?
  - How many contingencies are included in these studies?
  - Are the NERC TPL-001 planning standard contingencies included in the analysis, or at least a more stringent list of contingencies?
  - Are N-1-1 operating conditions considered?
- **Dynamic Stability Studies:**
  - What method is used to reduce the list of contingencies to study in dynamic simulations? How many contingencies are studied for each load interconnection in this domain?
  - Are electromechanical oscillations considered in dynamic studies?
  - Are the resonant effects of data center AI load ramping/variability considered in these studies (i.e., a form of forced oscillation)?
  - How are the stability impacts on nearby generators considered in these studies?
  - Are motor restart studies conducted?
- **Short-Circuit Studies:**
  - Are breaker duty studies conducted?
  - Are short-circuit studies (ASPEN, CAPE, etc.) conducted for large load interconnections, or are these studies only conducted in positive sequence simulation platforms?
  - How are impacts to protection systems analyzed for large load interconnections?
  - What protection system modifications must be made for these large loads?
  - What long-term effects are large loads having on short-circuit levels across the system? Are these effects positive or negative?
- **EMT Studies:**
  - Are EMT studies being conducted for large load interconnections? If not, why not?
  - Are fast-ramping and oscillatory behaviors of data centers, particularly AI data centers, studied by the utility in the EMT domain? How is the utility studying potential electromagnetic transients (e.g., capacitor switching)?

- How are subsynchronous oscillations, subsynchronous control interactions, and/or sub-synchronous torsional interactions being studied to ensure large loads do not cause serious adverse impacts or damage with existing power electronic controllers or synchronous generators?

Transmission Network Upgrades

- How is the utility coordinating with stakeholders to address transmission network performance deficiencies and assess potential network upgrades required for large load interconnections?
- What alternative solutions are considered as part of network upgrades beyond transmission infrastructure investments?
- What advanced technologies are included in these sensitivity assessments? Examples include GFMinverter technology, FACTS devices, high voltage DC (HVDC) technologies, controls tuning, BESS, etc.

Cost Allocation for Network Upgrades

- Are the large load customer direct connection facilities allocated the full costs of network upgrades?
- Is this consistent across transmission and distribution connections? Are existing load service requirements for typical residential, commercial, and smaller industrial facilities used for large load interconnections? Do practices need to adapt for large load customers, even if dispersed across multiple distribution load points?
- Is the large load customer entitled to any refund or discount of contributions made to direct connection costs?
- How are broader network upgrade costs allocated to large load customers?
- For any costs not fully accounted for by the large load customer, what cost allocation methodology is used for allocating the broader upgrades to large load customers versus being considered “network benefits”?
- How does the cost allocation methodology compare with utilities in different states or regions, and why?
- How are the full suite of network impacts considered in the cost allocation considerations? Examples include increased congestion levels, voltage issues, degradations in stability, reduced operational maintenance windows, etc.

Financial and Other Terms of Service

- Does the utility use tariffs or special contracts to hold large load customers to minimum load factors or a specified power factor range? How are customers penalized if they fail to meet these targets?
- Does the utility levy monthly demand charges? How are charges calculated—by contract capacity, peak demand from previous months, or a combination of both (i.e., demand ratcheting)?
- Do utility tariffs or contracts reserve the utility's right to reduce supply to large load customers when necessary to maintain grid reliability (e.g., during extreme weather events)?
- What language do utilities use to specify customers that are subject to large load tariffs? Do they identify industries by name, which may be discriminatory? Or do they identify the characteristics (volatility, non-permanence, etc.) that distinguish a load as extraordinary and qualify it for the tariff?
- Do utilities require collateral or minimum credit ratings from customers to protect against delinquent bill payment?
- Do utility tariffs specify an exit fee for large load customers that exit the tariff or terminate service before the end of the term?
- What are the terms of power purchase agreements offered by power plant operators and electricity markets? Do they enable customers to "game the system" (e.g., buying low-cost energy behind the meter and selling it back to the market for profit in times of high demand)?
- Who bestows economic development benefits and how do they determine eligibility? Must the customer meet a threshold for full-time equivalent jobs? Is the threshold too low or too high?

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Practical Guidance and Considerations for Large Load Interconnections

The electricity sector is poised for record demands and sustained growth in the years ahead. A 2023 study of nationwide demand trends found that grid planners had nearly doubled their five-year load growth forecasts from 2.6% to 4.7% in just one year. This surge is fueled by both individual and aggregated end-use loads with high electricity demands. Multi-sector electrification—driven by digitalization, heat pumps, electric vehicle charging, and other factors—continues to push overall electricity demand higher. However, the primary driver of demand growth is the wave of "large load" interconnection requests to the BPS· particularly form data centers.

This report serves as a practical guide to improving and harmonizing utility practices for processing, studying, and assessing large load interconnection requests. It also serves as a reference for state regulatory bodies in their effort to ensure that utility constituents are fully evaluating the potential impacts that large loads, particularly data centers, can have on grid reliability and existing customers. This guidance is especially useful in regions with limited experience integrating data centers and among utilities with constrained resources or bandwidth to stay current with evolving practices in this area.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Characteristics and Risks of Emerging Large Loads

Large Loads Task Force White Paper

July 2025

RELIABILITY | RESILIENCE | SECURITY




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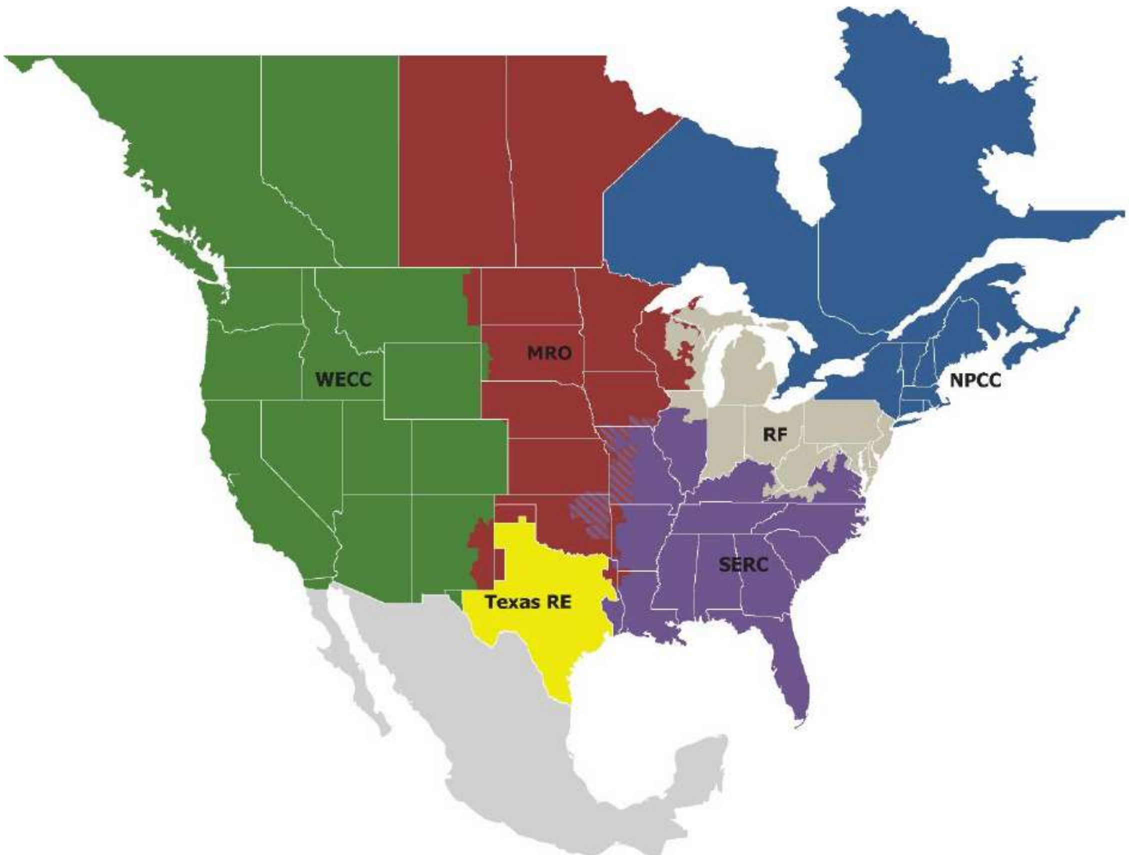
Preface

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

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



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

Executive Summary

A New Challenge on the Horizon

As the North American power system evolves, loads such as computational, industrial, and hydrogen production facilities are seeking to connect to the bulk power system (BPS) faster than ever before and at a magnitude beyond the largest currently operating loads. There is already evidence that large loads impact BPS reliability. For example, the Eastern and Electric Reliability Council of Texas (ERCOT) Interconnections have observed load-reduction events[1] with each Interconnection experiencing approximately 1,500 MW of voltage-sensitive load reduction. The event in the Eastern Interconnection was primarily attributed to data centers and other power electronic loads (PEL) transferring load to backup generation and caused frequency overshoot and high voltages. The ERCOT Interconnection event involved many different types of loads of varying size reducing consumption during an extended low-voltage period in West Texas due to a protection system misoperation. These load-reduction events highlight some of the potential risks posed by large loads utilizing the BPS and why NERC is closely examining this issue.

There is already evidence that large loads impact bulk power system reliability.

NERC'S Response

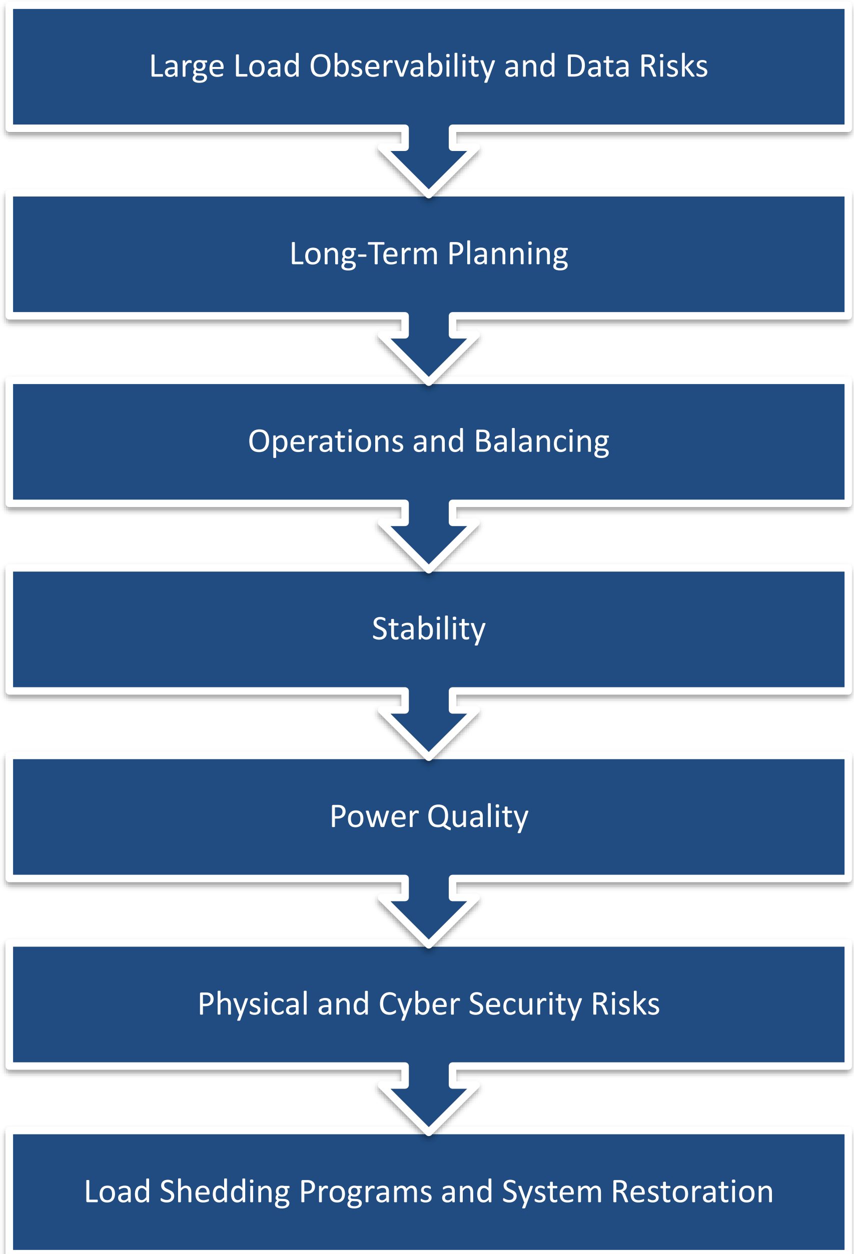
NERC's Reliability and Security Technical Committee (RSTC) established the Large Load Task Force (LLTF) to analyze the reliability impacts related to emerging large loads (e.g., data centers (including cryptocurrency mining, and artificial intelligence (AI)), industrial facilities, and hydrogen production facilities). This white paper characterizes large loads and defines the reliability risks that they may pose to the BPS. A reliability gap analysis white paper will follow, shedding more light on where the most significant risks exist.

To better understand the reliability impacts, NERC established the Large Loads Task Force.

The loads examined in this paper range in size from several megawatts to several gigawatts, posing novel challenges to the reliability and security of the BPS. Several Reliability Coordinators (RC) and utilities have existing large-load constructs based primarily on facility peak demand. However, additional characteristics should be considered in any definition of large loads, as this white paper shows that peak demand is only one of many characteristics that can impact BPS reliability.

[1] "Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions," NERC, Jan. 2025. Available: https://www.nerc.com/pa/rrm/ea/Documents/Incident_Review_Large_Load_Loss.pdf

The LLTF analyzed the following risk categories for this white paper:

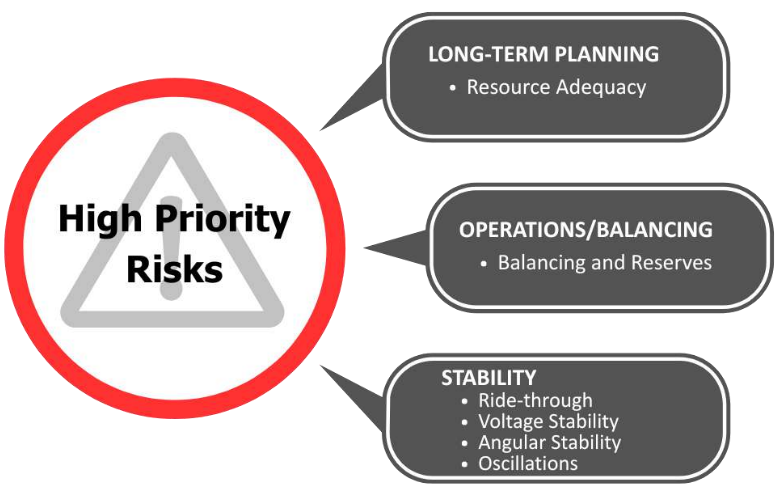


The following recommendations are offered as guidance for future work to ensure the reliability and security of the BPS:

- ✓ **Recommendation 1:** The NERC LLTF should identify existing processes and standards that do not fully address the risks of emerging large loads, as planned for the LLTF's second work item—*White Paper: Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads*.
- ✓ **Recommendation 2:** The LLTF should identify potential mitigations to risks posed by emerging large loads through improvements to existing planning and operation processes and interconnection procedures for large loads as planned for the LLTF's third work item—*Reliability Guideline: Risk Mitigation for Emerging Large Loads*.
- ✓ **Recommendation 3:** The LLTF should clearly define each of the identified characteristics of emerging large loads and develop a framework for classifying large loads.
- ✓ **Recommendation 4:** The NERC Load Modeling Working Group should create and approve load models that can show the characteristics and risks of each category of emerging large loads in simulations.
- ✓ **Recommendation 5:** The NERC System Protection and Control Working Group should assess possible protection system impacts to the BPS from emerging large loads.
- ✓ **Recommendation 6:** The NERC Energy Reliability Assessment Working Group and Probabilistic Assessments Working Group should investigate methods for grid operators and planners to assess the risks potentially posed by emerging large loads to resource adequacy.

Next Steps

To address the near- and long-term risks associated with large loads, NERC is identifying gaps in integrating these large loads onto the grid, enabling a coordinated approach to address this issue effectively. This white paper is expected to be published in Q4 2025.



Chapter 1: Introduction to Large Loads

Intended Audience

This white paper is intended for the following NERC registered entities, external entities, and broader groups:

- Planning Coordinators (PC)
- Transmission Planners (TP)
- Transmission Owners (TO)
- Transmission Operators (TOP)
- Distribution Providers (DP)
- Balancing Authorities (BA)
- Reliability Coordinators (RC)
- Large load developers, owners, operators, or other related companies
- Generator Owners (GO)
- Generator Operators (GOP)
- Reliability and Security Technical Committee (RSTC) subgroups

This white paper identifies, validates, and prioritizes the characteristics and risks of emerging large loads to the BPS. Entities responsible for operating and planning facilities on the BPS should be aware of these characteristics and risks to maintain reliable service. Subsequent LLTF work items, like the next white paper and reliability guideline, will need to address the risks noted in this white paper. Finally, this white paper identifies areas where potential security risks associated with emerging large loads require further assessment by related RSTC subgroups.

NERC Large Loads Task Force

The purpose of the NERC LLTF is to better understand the reliability impacts that emerging large loads, such as data centers and other computational loads, large industrial loads, and hydrogen production facilities, will have on the BPS. The LLTF has two primary phases identified in the NERC LLTF scope[2] as follows:

- Phase 1: Identify unique characteristics and risks of large loads
- Phase 2: Identify gaps and potential risk mitigation

Large Load Definition

NERC's LLTF was tasked with defining large loads. The definition was created for use in this white paper and the other work products from NERC's LLTF. This definition is expected to be modified in the future for specific applications, like the *NERC Glossary of Terms Used in NERC Reliability Standards*.[3] For the purposes of this white paper and the following white paper and reliability guideline, large loads shall be defined as the following:

"Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors. Examples include, but are not limited to, data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces."

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[2] "Large Loads Task Force (LLTF)," NERC, Aug. 2024. [Online]. Available: https://www.nerc.com/comm/RSTC/LLTF/LLTF%20Scope.pdf

[3] "Glossary of Terms Used in NERC Reliability Standards," NERC, Feb. 2025. Available: https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf

The LLTF has not yet provided a megawatt (MW) threshold or more granular characteristics of large load as further analysis and development is forthcoming.

Background

Emerging large loads have grown substantially in recent history, and forecasts predict that data centers alone may account for as much as 12% of all U.S. electricity consumption by 2028[4] (up from 4.4% in 2023). In addition to the rapid, demonstrated, and forecasted growth of emerging large loads, the characteristics that inform their electrical behavior are not as predictable as conforming loads. The electrical behavior of emerging large loads during both normal and abnormal grid conditions represents new challenges for planners and operators. Operating experience is limited with emerging large loads. Large loads may come in different forms, although the rapid growth associated with data centers have led the authors of this white paper to focus on the characteristics and potential risks associated with integrating these types of users of the BPS. This white paper will discuss emerging large loads' characteristics and how each one informs specific risks to the BPS.

[4] A. Shehabi *et al.*, "2024 United States Data Center Energy Usage Report," Lawrence Berkeley National Laboratory, Dec. 2024. Available: https://eta-publications.lbl.gov/sites/default/files/2024-12/lbnl-2024-united-states-data-center-energy-usage-report.pdf

Chapter 2: Characterization of Large Loads

This chapter categorizes the large loads that have emerged in recent years across North America, reviews existing large load programs and constructs in the United States and Canada and addresses certain factors that could inform a formal NERC large load definition.

Large load customers are connecting to the grid faster than ever before. These loads range widely in size: some are facilities of several MWs that can connect at the distribution level, while others are multi-gigawatt (GW) complexes that must be served by the transmission system and may require new transmission facilities or other upgrades to support the increased system demand.

In addition to their size, large loads have other characteristics that pose reliability risks to the BPS. For example, many new large loads are PELs that use software controls to manage the load behavior rather than the mechanical controls used by older motor loads. PEL control systems enable loads to rapidly change electricity consumption, creating previously unseen load behavior that can cause BPS planning and operational challenges.

Categories of Large Loads

The following large load categories are based on the function or activity of the facility in question. Each type will require tailored considerations for interconnection, BPS reliability, and grid integration.

Data Centers and Other Computational Load

A data center is a physical room, building, or facility that houses IT infrastructure for building, running, and delivering applications and services.[5] Data centers are among the fastest-growing energy consumers in North America, supporting cloud computing, AI, cryptocurrencies, and other digital services. They range from hyperscale facilities operated by tech giants, like Meta's planned 2 GW AI training facility in Louisiana,[6] to smaller data centers that serve multiple enterprises. Some data center loads are known to have pulsed and non-linear characteristics, giving them extremely quick ramping potential that can introduce power quality and stability issues. Cryptocurrency mines are generally not classified as data centers though much of their makeup is similar. Cryptocurrency mines may have different types of IT equipment compared to traditional and AI data centers, and they may not prioritize uptime as much as a traditional data center.

Data centers and other computational loads are PELs that consist of high-performance computing (HPC) systems in which large clusters of computing resources work in concert to perform complex analysis and other tasks. These loads are characterized by high energy consumption, variable operational demand, and significant cooling requirements. "Data center" is a term that encompasses many different end uses and configurations, as explained in this section's various sub-sections. The internal configuration of the load can be very complex, including internal protection and backup power systems. Data centers and other computational loads are often located in areas with access to reliable and cost-effective electricity, requiring carefully tailored grid planning and interconnection strategies.

[5] S. Susnjara and I. Smalley, "What is a data center?," IBM Think, Sep. 04, 2024. https://www.ibm.com/think/topics/data-centers (accessed May 27, 2025).
[6] "Meta's Richland Parish Data Center." Available: https://datacenters.atmeta.com/wp-content/uploads/2024/12/Metas-Richland-Parish-Data-Center.pdf

The four main components in data centers are listed as follows:

- **IT-related equipment** consists of servers, storage, and networking gear driven by power electronics. These components generally comprise at least half of the data center's energy consumption.[7,8] Data center industry experts state that IT-related equipment may make up 60–95% of a data center's total energy demand.
- **Power delivery systems** control and distribute power in the facility. They may consist of multiple sources of external power, internal power distribution systems, emergency backup systems (including uninterruptible power supply (UPS) and on-site generation), and sophisticated control systems that ensure continuity of service to their critical network equipment. Data center industry experts note that power delivery systems for HPC loads (AI data centers) commonly exclude UPS protection systems for the IT equipment. Instead, they employ a checkpoint process where checkpoints are saved at regular intervals. If there is an interruption to the IT equipment's power, the checkpoint may be restored after the power interruption ends.
- **Cooling systems** typically consist of PEL including variable speed drives, inverters, and other internal equipment that can create harmonics and increased reactive power demands.
- **Miscellaneous** lighting and security loads are necessary for operation of the load. This typically makes up the smallest portion of the total energy usage of the load.

Figure 2.1 shows how these components and other features, such as UPS and backup generation, may be arranged in a data center. Notably, the desired uptime of the facility determines what tier of backup equipment is required. This figure is more relevant to traditional data centers. For AI training loads, there may be no UPS for the IT equipment.

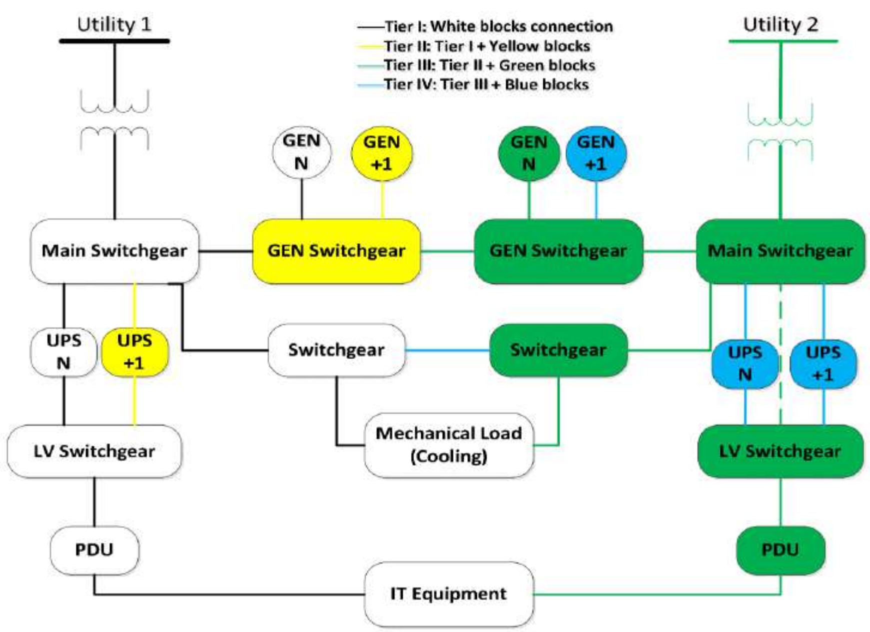

Figure 2.1: Tier I–IV Data Center One-Line[9]

[7] J. Davis, "Large data centers are mostly more efficient, analysis confirms," *Uptime Institute Blog*, Feb. 07, 2024. https://journal.uptimeinstitute.com/large-data-centers-are-mostly-more-efficient-analysis-confirms/
[8] "Technical Update on Load Modeling. EPRI, Palo Alto, CA: 2023. 3002027016"
[9] S. Chalise et al., "Data center energy systems: Current technology and future direction," 2015 IEEE Power & Energy Society General Meeting, Denver, CO, 2015, pp. 1-5, doi: 10.1109/PESGM.2015.7286420.

Traditional Data Centers

Traditional data centers power the digital services of the modern world. They enable almost every online service, including banking, healthcare, e-commerce, and social media.[10] Traditional data centers make up most of the currently operational data centers and exclude AI training and inference facilities. The exact configuration and business model can vary greatly, but most traditional data centers have similar electrical characteristics. Traditional data centers have historically been characterized by their smaller size[11] (under 30 MW in many cases) and limited variability. Traditional data centers commonly prioritize up time – the percentage of time that a data center provides uninterrupted service. These types of data centers are known for their redundancy. There are a few organizations, like the Uptime Institute,[12] that classify data centers into Tiers I-IV. Tier IV data centers have the highest redundancy, resulting in uptimes of over 99.995%.

Some companies, like utilities, use small local data centers to meet their business needs. These types of data centers are typically very small (less than 1 MW) and are not the focus of this white paper.

Larger businesses may use self-hosted data centers for their own business use cases. Social media is a prime example of this, as it takes many large data centers to host services that are used by millions of people. These data centers are owned and operated by a single company, so they will have the most information available about physical infrastructure, electrical characteristics, and demand patterns.

The last major type of traditional data center is the cloud data center, which may rent out its computing power to multiple businesses on a recurring or temporary basis. These data centers have information about the physical equipment and characteristics but may not have as much information on demand patterns as a self-hosted, self-use data center.

Artificial Intelligence Training Data Centers

Data centers powering AI technologies are among the newest types of load customers. AI is generally defined as technology that enables computers to perform complex tasks like translating spoken and written language, analyzing data, and making recommendations.[13] AI training refers to the creation and modification of an AI model and its associated model weights.

AI facilities (training and inference) include powerful, application-specific integrated circuits (ASIC) or graphics processing units (GPU). Current industry trends, especially in AI applications, show GPUs getting smaller with higher power ratings than historic GPUs. These computing components operate best in very specific conditions, requiring specific temperatures and humidity. This is often a key consideration when siting data centers. If temperature and humidity ranges are too vast, the temperature and humidity control equipment may be too burdensome. Cooling load demand can vary widely depending on the specific data center's cooling equipment and based on the intensity of the processing tasks that the IT equipment is assigned at any given time. The cooling load requirements are highly dependent on the end use. For instance, cooling load has different characteristics for AI data centers compared to traditional data centers.

The electrical demand is different for training an AI model versus using an AI model to create inferences.[14] Generally, AI training executed in large clusters has rapid fluctuations during training periods and while saving checkpoint

[10] "What is a datacenter? - Microsoft Datacenters," Microsoft Datacenters, May 05, 2025. https://datacenters.microsoft.com/whatisadatacenter/

[11] B. Srivathsan, M. Sorel, and P. Sachdeva, "AI power: Expanding data center capacity to meet growing demand," *McKinsey & Company*, Oct. 29, 2024. https://www.mckinsey.com/industries/technology-media-and-telecommunications/our-insights/ai-power-expanding-data-center-capacity-to-meet-growing-demand

[12] "Tier Classification System," Uptime Institute. https://uptimeinstitute.com/tiers

[13] Google Cloud, "What Is Artificial Intelligence (AI)?," *Google Cloud*, 2025. https://cloud.google.com/learn/what-is-artificial-intelligence

[14] Trends in AI inference energy consumption: Beyond the performance-vs-parameter laws of deep learning, https://doi.org/10.1016/j.suscom.2023.100857

progress. Additionally, the transition from training to saving checkpoint progress (or vice versa) may happen in under one second. See **Figure 2.2** and **Figure 2.3**, which shows the demand from a 50 MW block of a larger 200 MW AI training data center that starts a training run. The data was recorded with a high-speed recorder and was supplied by EdgeTunePower.[15] In the fastest ramping period, the demand changes at a rate of 1.9 p.u. per second for about 250 milliseconds.

While the training is active, jittery spikes up and down occur, shown between 360 and 660 seconds in **Figure 2.2**. Google explains the problem in a Google Cloud blog post,[16] stating that large power spikes are observed when transitioning between "idle and peak utilization levels" but that they also occur "when the workload is running normally, mostly attributable to alternating compute- and networking-intensive phases of the workload within a training step."

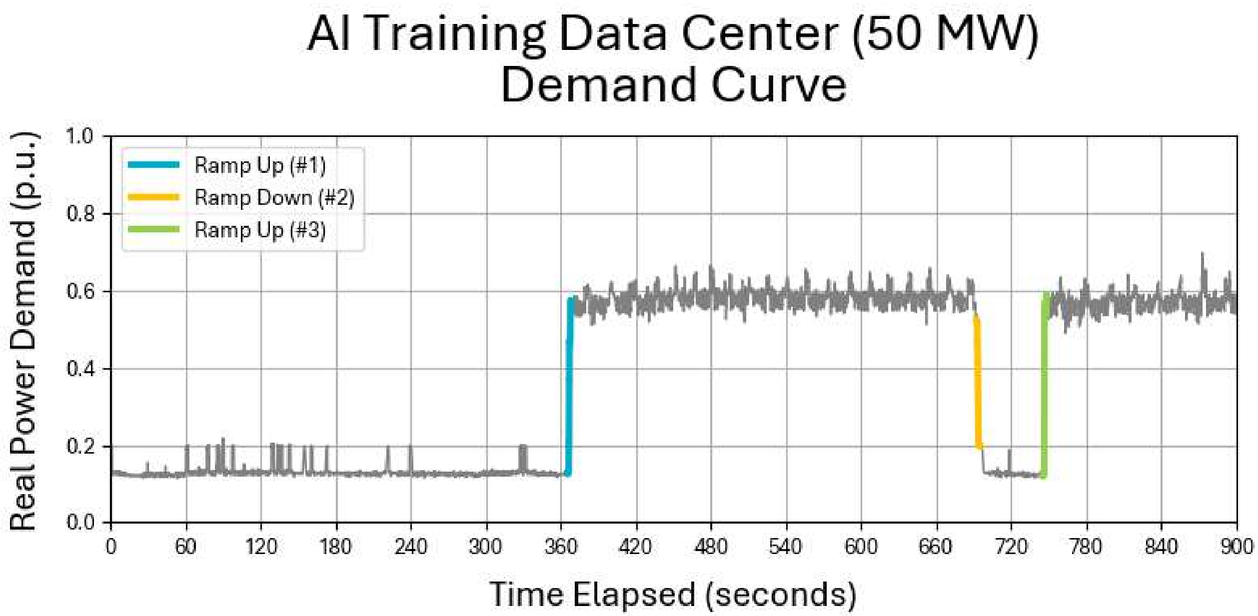

Figure 2.2: An AI Training Data Center Begins a Training Run (EdgeTunePower)

[15] "About Us | EdgeTunePower," *EdgeTunePower*. https://www.etpower.ca/about-us

[16] H. Gan and P. Ranganathan, "Balance of power: A full-stack approach to power and thermal fluctuations in ML infrastructure," *Google Cloud*, Feb. 11, 2025. https://cloud.google.com/blog/topics/systems/mitigating-power-and-thermal-fluctuations-in-ml-infrastructure (accessed May 29, 2025).

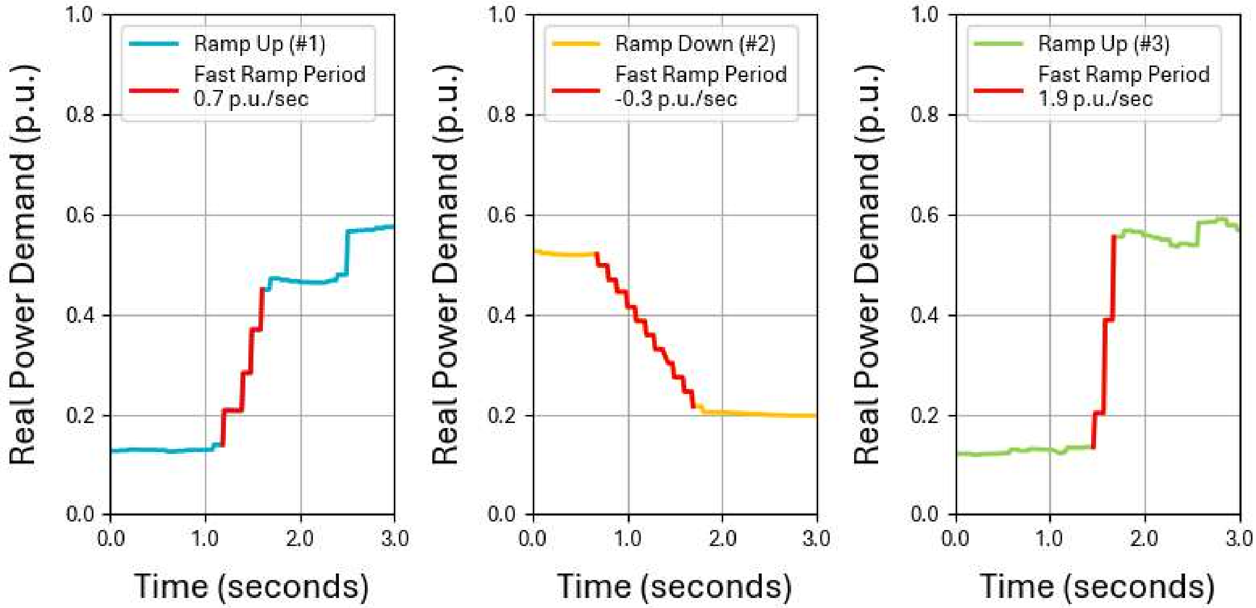

Figure 2.3: Zoomed-In Views of AI Training Data Center Ramping Up and Down Due to Transitioning Between Training and Saving Checkpoint Progress

Artificial Intelligence Inference Data Centers

AI inference is the process of using a pre-trained AI model to generate output(s) based on new input. AI inference uses similar, high-power GPUs when compared to AI training. It is common for data centers to be purpose-built for either inference or training workloads. The primary difference is in the underlying computations happening on the GPUs. The rapid ramps up and down seen in AI training/checkpoint cycles are not observed in current AI inference methods. Some companies in the AI industry, like NVIDIA, postulate that inference will be the greater electrical demand in the future when compared to training. In February 2022, Google stated that 60% of its total energy use went toward inference and 40% went toward training.[17] However, this was before some of the largest growth in large language models (LLM) and AI over the past three years.

Cryptocurrency Mining

Cryptocurrencies (e.g., Bitcoin) rely on "data mining," wherein computers solve mathematical puzzles to validate and enable various transactions. Cryptocurrency mining facilities consist of purpose-built servers and mining units—typically ASIC miners. Depending on the size of the operation and the number of units, cryptocurrency mining can consume large amounts of electricity to power the machines and cool the equipment.

Unlike data centers, which ramp up or down in response to customer demands or training cycles, the power consumption of cryptocurrency mining facilities is more stable and typically driven by internal computational needs, giving cryptocurrency miners flexibility in responding to system conditions, like reducing demand when prices are high.

Industrial Load

Industrial loads consist of facilities and equipment used for producing, processing, or assembling goods. These operations often require robust electric infrastructure and are typically more complex and energy-demanding than residential or commercial loads. Industrial loads are commonly referred to as non-conforming loads. This sector is set

[17] D. Patterson, "Good News About the Carbon Footprint of Machine Learning Training," *Google Research*, Feb. 15, 2022. https://research.google/blog/good-news-about-the-carbon-footprint-of-machine-learning-training/ (accessed May 28, 2025).

to grow as more industrial activity moves to North America and existing facilities replace oil and gas with electricity as a primary fuel source.

Mining and Mineral Processing

The mining and mineral processing industries extract and refine raw materials essential for sectors including hard rock mining, coal mining, mineral processing, and cement production.

Metals and Heavy Manufacturing

Metals and heavy manufacturing consists of industries involved in the processing of metals and large-scale manufacturing, including steel mills, smelters and metal refineries, rolling mills, foundries, and casting facilities.

These industries use electricity-intensive processes, including electric arc furnaces (EAF), induction furnaces, electro-refining, arc welding and plasma cutting, and large-scale electrolysis.

Semiconductor and Electronics Manufacturing

These industries require precision power and cleanroom environments. Examples include semiconductor fabrication, liquid-crystal display (LCD) and organic light-emitting diode (OLED) and display manufacturing, battery manufacturing, and printed circuit board (PCB) production.

Chemical and Petrochemical Processing

These industries rely on high-energy chemical reactions to facilitate their processes. Examples include ammonia and fertilizer plants, chlor-alkali and electrochemical processing, refining and petrochemicals (oil refineries, synthetic fuels, plastics), and carbon capture and utilization (CCU).

Oil and Gas Production

The production of oil and gas requires vast amounts of energy. To improve oil and gas field equipment efficiencies and reduce costs, many operators are switching equipment to run on electricity and not fossil fuels. The buildout of liquefied natural gas plants is also driving load growth in certain regions of North America.

Hydrogen Production Facilities

This white paper focuses solely on hydrogen production facilities that use electricity to perform electrolysis. Hydrogen is an emerging option in the push to decarbonize the grid. The hydrogen production process begins at a hydrogen production plant, where water is treated and purified to remove dissolved solids, organic compounds, and other contaminants, resulting in pure water (H_2O).

This purified water then undergoes electrolysis, which splits the water into hydrogen and oxygen molecules. Each electrolyzer used in this process typically consumes 5–10 MW of power, and multiple units can operate within the same facility, as shown in **Figure 2.4**. After electrolysis, the hydrogen is cooled and liquefied. Liquid hydrogen can then be stored or transported for use in various applications, including fueling vehicles (e.g., cars, trucks, airplanes), powering data centers, providing backup power, and supporting manufacturing processes.

Hydrogen electrolyzer facilities under development could reach the multi-gigawatt scale. Initial surveys have shown that over 85% of the facility load consists of power electronic converters with the remaining load being motor driven for H2 compression, water treatment and cooling, and other plant equipment.

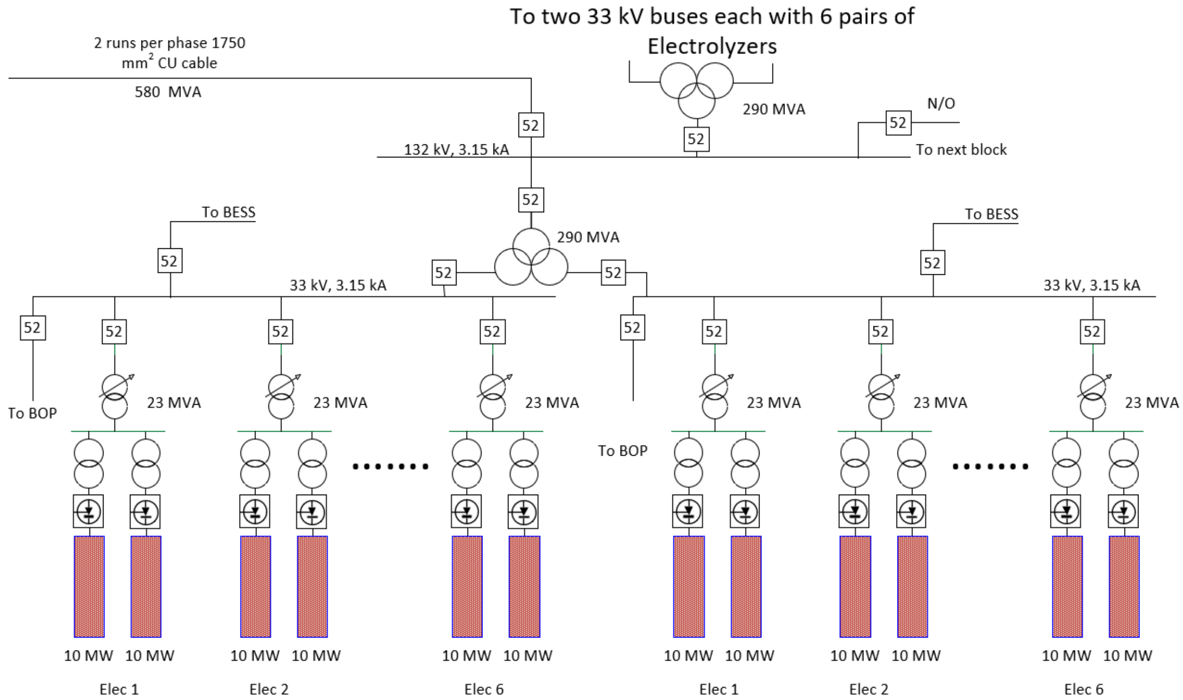

Figure 2.4: Example Hydrogen Production Facility One-Line Diagram (EPRI)

Example Existing Large Load Programs and Constructs

Several entities in North America have requirements for large load interconnection and/or preliminary definitions and programs for large loads. Notably, the only organizations included in this white paper are ones that voluntarily provided information to the writers of the white paper. Of the RCs and utilities with existing large load constructs, many of the current constructs are based on transmission facility ratings with no additional accounting for the potential impact that large loads may have on the BPS. Utility-specific programs not detailed in this section are described in **Appendix A: Large Load Construct Data**. All information about programs and constructs in this white paper reflects current practices and is subject to change.

Reliability Coordinators

ERCOT

In the ERCOT Interconnection, a large load is defined as 75 MW or larger. At this size, transmission service providers (TSP) in ERCOT typically must develop and construct transmission upgrades to support the full amount of load that is seeking interconnection.

ERCOT established an interim large load interconnection process through Market Notice W-A032522-01[18] to ensure compliance with existing NERC requirements and for the reliable interconnection of large loads to the ERCOT system. TSPs are required to submit interconnection studies that meet the requirements of NERC Reliability Standard FAC-002-2 for each applicable large load proposing to interconnect to the ERCOT system.

[18] "Market Notice - Interim Large Load Interconnection Process," *Ercot.com*, Mar. 25, 2022. https://www.ercot.com/services/comm/mkt_notices/W-A032522-01

ERCOT's interim large load program applies to projects seeking to interconnect in two years or less that meet one of the following criteria:

- For standalone loads not co-located with a generation resource:
  - A new load is requesting a total peak demand of 75 MW or more
  - An existing load is requesting an increase of its total peak demand by 75 MW or more
- For loads co-located with a generation resource:
  - A new load is requesting a total peak demand of 20 MW or more
  - An existing load is requesting an increase of its total peak demand by 20 MW or more

NYISO

To supplement the load interconnection procedures in the New York Independent System Operator (NYISO) Open Access Transmission Tariff (OATT), NYISO has defined load interconnection procedures in its *Transmission Expansion and Interconnection Manual*. These procedures specify which load interconnections are subject to NYISO's interconnection studies: those with a load of 10 MW or greater connecting at a voltage level of 115 kV or above or a load 80 MW or greater connecting at a voltage level below 115 kV. Such projects must be evaluated to determine whether they may degrade system reliability or adversely affect the operation of the New York state transmission system.

NYISO performs a single interconnection study, the System Impact Study, for load interconnections, the scope and results of which are reviewed by NYISO's operating committee. If the System Impact Study indicates the potential for an adverse reliability impact, NYISO identifies the need for potential upgrades required to reliably interconnect the load project. Should the load customer elect to proceed, required upgrades are evaluated by the applicable TO(s), and the engineering, procurement, and construction details as well as the cost responsibility for such upgrades are memorialized in Interconnection Agreements between the load customer and the applicable TO(s).

Projects that do not meet the above MW/voltage thresholds are subject entirely to the connecting TO(s) load interconnection procedures; NYISO is not involved in any interconnection studies for such projects.

Southwest Power Pool (SPP)

The Delivery Point Addition Process in SPP, defined under Attachment AQ of the SPP tariff, governs how new or modified delivery points are added to the transmission system. A delivery point is where power is transferred from the grid to a local utility or load-serving entity. When a new delivery point is proposed or an existing one is changed, the transmission customer (TC) submits a delivery point assessment (DPA) request. The transmission provider, SPP, then performs an engineering study to assess reliability impacts, and the host TO performs a load connection study (LCS) to assess load interconnection needs. SPP reviews the LCS, coordinates with stakeholders, and determines if system upgrades are needed. Costs for network upgrades are regionally funded, and interconnection facility upgrade costs are agreed upon between the TC and TO. Once approved, the delivery point and associated upgrades are added to the TC's service agreement, ensuring that the agreement is recognized in planning, operations, and billing. This process ensures reliability, coordination, transparency, and fair cost allocation across the SPP system.

ISO-NE

The Independent System Operator New England (ISO-NE) does not have an explicit "large loads program." However, ISO-NE learns of new loads seeking to interconnect through either a transmission service application for new load (regional network load or local network load) under regional network service (typically 115 kV or above) or local network service (typically below 115 kV, not including distribution facilities), depending on how the new load would be served. However, large data center loads have not yet sought interconnection in the area through application for these services, and there is no definition of "large loads."

Only applications for wholesale service are submitted to ISO-NE. Applications for retail service to serve load are submitted to the New England TOs, and ISO-NE has no visibility into those applications.

Utility-Specific Programs

In this category, Dominion Energy has the most experience with large load interconnections because Virginia (which is within Dominion's service area) is home to the world's largest concentration of data centers. Other known utility-specific programs are described in **Appendix A: Large Load Construct Data**.

Dominion

Per Section 2.13 End User Facilities (Load Interconnection) of the Electric Transmission Facility Interconnection Requirements End Users Facilities,[19] Dominion sets a 100 MW threshold for loads tapping the transmission system at a single point of interconnection. Below 100 MW, Dominion allows the load to be tapped with only isolation switches; above 100 MW, a ring bus configuration is required. As part of Dominion's planning criteria, the amount of load connected to a single substation is limited to 300 MW and requires no more than 300 MW load loss for N-1 and N-1-1 contingencies.

For any load connection to the transmission system, Dominion requires customers to submit a detailed request form with specific sections for data centers that require information about ride-through capabilities and other features. The Dominion 500 kV system is reserved for bulk power transfer, and load interconnections are not allowed to reach this voltage. Most data center load connections are on the 230 kV system, but some occur on the 115 kV and 138 kV systems.

Future Large Load Definition Considerations

Given the numerous categories and subtypes of large loads, a classification system based solely on a load's peak demand may be overly simplistic. Due to the differences highlighted above, it cannot be assumed that all loads will behave similarly. Several other factors, such as load ramp rates, real-time behavior and flexibility, protection systems, and backup power schemes, should be considered if a large load definition is developed for regulatory procedures or policies. Some of the additional factors for consideration are described below.

Single Number vs. Size Range

In November 2024, a subgroup of the NERC LLTF conducted an informal survey to gather feedback from participants on what load size should qualify as "large" under a potential NERC regulatory construct. Most of the survey respondents qualified "large" as greater than 50 MW, and the single size number most commonly suggested was 75 MW.

However, the survey also revealed that "large" may be relative to other factors, such as the voltage to which the load is interconnected. For example, a consuming site with a 20 MW peak demand would be considered "large" for distribution service, whereas 20 MW is a relatively small customer if interconnected at transmission voltage. Additionally, the relative size of the load to the local system and overall interconnection affects how it impacts BPS reliability. For instance, frequency stability looks different in the Eastern Interconnection compared to the ERCOT Interconnection.[20] Additionally, even within the ERCOT Interconnection, voltage stability considerations are different in each zone.

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[19] Dominion Energy Virginia, "Electric Transmission Facility Interconnection Requirements," Apr. 01, 2025. https://www.dominionenergy.com/-/media/pdfs/virginia/parallel-generation/facility-connection-requirements.pdf?la=en&rev=07744be57e5a439988e46f630af76e6f (accessed Jun. 06, 2025).
[20] "2024 Frequency Response Annual Analysis," Nov. 2024. [Online]. Available: https://www.nerc.com/comm/OC/Documents/2024_FRAA_Report_Final_Draft.pdf

While defining a singular size could be a way to establish a clear threshold for future regulations, policies, and standards, it could also create unjust or unreasonable unintended consequences. For example, a single number may motivate regulated entities to intentionally size beneath to avoid regulation. This is not to say that size is irrelevant; it is rather that size alone would be too limited a way to examine what is a materially impactful large load.

Behind-the-Meter Loads

The increasing prevalence of behind-the-meter (BTM) large loads is an important issue in the landscape of electric markets, grid reliability, and operations. Figure 2.5 illustrates the difference between front-of-meter (FOM) and BTM configurations. BTM large loads receive their energy directly from co-located generators without the use of the transmission or distribution grid. In certain configurations, the load is served partially through FOM and BTM configurations.

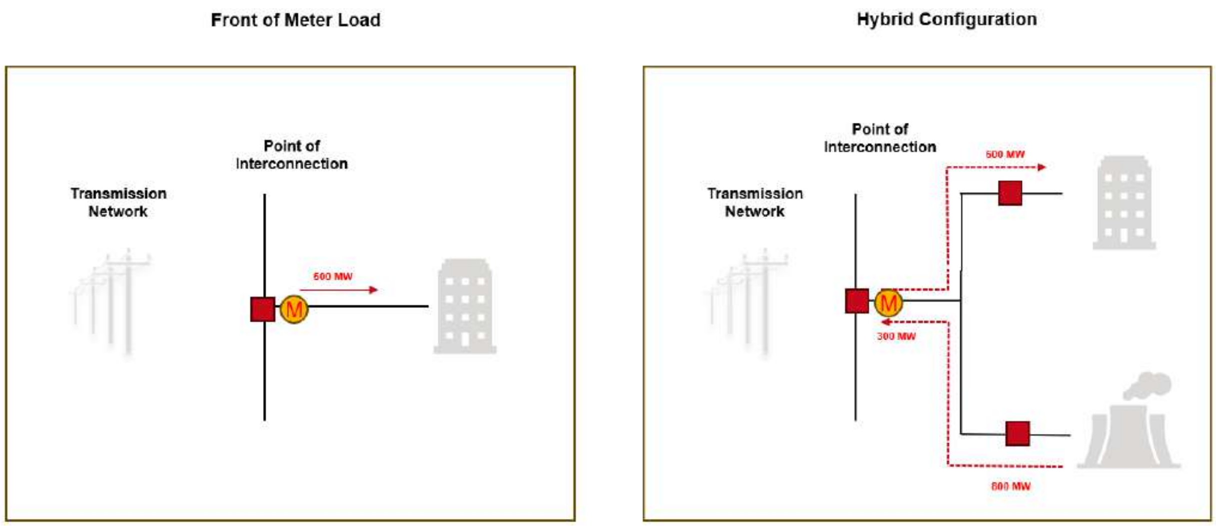

Figure 2.5: FOM vs. BTM Load Illustrations[21]

When a load is served exclusively by a co-located generator, protection mechanisms are typically installed to prevent grid energy from flowing to the load. In these instances, if the co-located generator is out of service, the load will also be disconnected unless it possesses backup generation of its own. Figure 2.6 demonstrates the effects of a generator outage when the load is served exclusively by co-located generation.

[21] The metering configuration in the BTM configuration example is for illustration purposes only; specific metering design for BTM configurations will depend on the metering practices of the interconnecting utility or utilities.

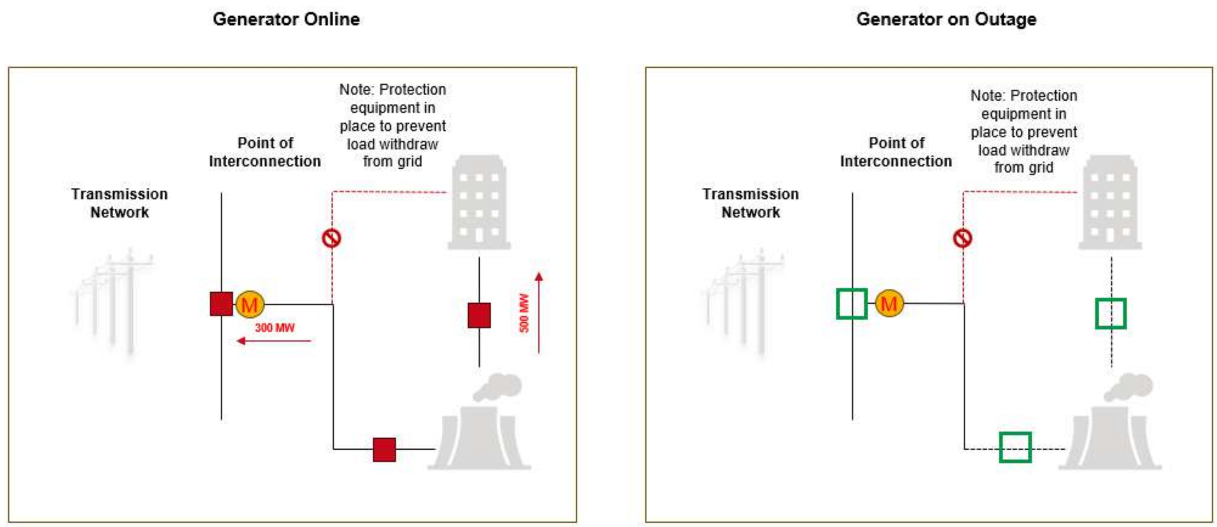

Figure 2.6: BTM Online vs. On Outage

As BTM large loads continue to develop, their impact on operational visibility, independent system operator (ISO) control, and system stability becomes increasingly influential. Below is a list of characteristics that impact the BPS:

- **Operational visibility differs between FOM and BTM loads.** FOM loads are directly integrated into the transmission or distribution system and are usually visible to the interconnecting utility and/or the system operator in the operational environment. In contrast, depending on the utility's requirements, BTM loads may not undergo the same level of impact analysis during the interconnection process. As a result, BTM resources can pose reliability risks if their generation unexpectedly trips off-line and appropriate protection or ride-through systems are not in place. The operational visibility and controllability of BTM loads are limited, making it more challenging to predict system impacts, especially during uncontrolled transitions between on-site generation and grid supply that may arise due to protection system failures.
- **Load or generator trips pose risks to system stability.** In cases where co-located generation suddenly trips off-line, the co-located load might not seamlessly transition to grid supply unless a formal interconnection agreement exists with the utility, leading to a sudden interruption of service to this load. If the load unexpectedly shifts to grid supply after the co-located generation fails, the utility supply sees a rapid demand spike, which may stress the transmission system.
- **Size and interconnection type matter.** Large BTM loads shifting to the grid during generator outages can disrupt system stability and cause capacity shortfalls or resource adequacy issues. Clear interconnection standards, monitoring, and coordination are needed to prevent unexpected demand swings and ensure reliable operations.

Real-Time Load Behavior

Each category of large load—computational, industrial, and hydrogen—displays real-time operating characteristics that differ from loads previously connected to the BPS. These loads are typically not controllable by the utility or ISO unless they voluntarily enter into a load curtailment or demand-response program. The choice to participate in such programs is usually an individual customer strategy based on an economic evaluation (i.e., customers that have flexible processes may be able to earn revenue from such programs through demand reductions during periods of high grid stress). Certain control areas allow loads to provide ancillary services, like ERCOT's Controllable Load Resource program.[22] These programs are all voluntary.

Many large loads, such as cryptocurrency mining and AI facilities, can cycle their consumption on and off in less than a minute and can ramp from zero to hundreds of MW of power demand over very short time frames, like in the previously mentioned **Figure 2.2** and **Figure 2.3**. As a comparison, data centers that support cloud computing and digital services typically have high load factors and non-conforming behavior, so their consumption is relatively static.

Firm Load vs. Flexible Load

Large loads interconnecting to the grid typically request firm utility service during the interconnection process. This means that the utility is required to provide the transmission infrastructure capable of serving the load's peak demand request at all times.

Concepts have been explored[23] in some areas around mandatory load curtailments by the ISO or utility during stressful grid conditions, which might allow for TPs to assume a lower peak demand for the load and potentially reduce the transmission buildout exclusively needed to support the load. Utility controllability of loads is usually not accounted for at the transmission planning stage. However, many loads are still expected to obtain firm transmission service to ensure reliable electric service delivery, necessitating transmission buildouts to support the load and an increase in energy supply during both normal and emergency system operations.

[22] "Load Resource Participation in the ERCOT Markets," *ERCOT*, 2021. https://www.ercot.com/services/programs/load/laar (accessed May 30, 2025).

[23] T. Norris, T. Profeta, D. Patino-Echeverri, and A. Cowie-Haskell, "Rethinking Load Growth: Assessing the Potential for Integration of Large Flexible Loads in US Power Systems," Nicholas Institute of Energy, Environment, & Sustainability, 2025. Accessed: May 30, 2025. [Online]. Available: https://nicholasinstitute.duke.edu/sites/default/files/publications/rethinking-load-growth.pdf

Chapter 3: Risks to the Bulk Power System

The interconnection of emerging large loads may pose reliability risks to the BPS, and the LLTF has reviewed, categorized, and prioritized these risks. Grid planners and operators need to consider large loads in both the planning and operations domains to ensure that the transmission system is properly planned considering these loads. They must also ensure that the system can be reliably operated in real time with adequate reserves. Large loads can pose numerous risks to the BPS reliability, as discussed below.

Large Load Observability and Data Risks

System operators and planners need data and models about large loads to properly characterize the load's behavior and study potential risks to the BPS. To run steady-state and dynamic simulations, for example, the operator and planner need to know the expected interconnection timelines, peak demand, load behaviors, protection and control settings, and dynamic models for the load. Without this data, operators and planners cannot properly account for the load's effect on the rest of the BPS, potentially leading to poor operating and planning decisions and poor real-time situational awareness.

Currently, developers, owners, and operators of large loads are not required to be NERC registered entities under NERC's Registry Criteria Rules of Procedure. This means that large loads are not required to adhere to Reliability Standards. Operators have already cited multiple events in the Eastern Interconnection (EI) and ERCOT systems that involved large loads in which it was difficult to obtain information from the large load customer, impeding the operator's ability to investigate loss-of-load events. While load currently does not need to register or be involved in the investigation, the magnitude of these loads poses a risk to system stability if the loads behave unexpectedly. Additionally, the control systems of these loads can interact with the grid, exacerbating oscillations and other phenomena. If there is no high-speed recording data available, diagnosing the root cause and fixing it may be difficult or impossible.

In addition to impeding proper planning, the lack of high-resolution measurement data from large loads will hinder system operators' ability to analyze events after they occur. Few loads have phasor measurement units (PMU) or other ways to monitor their behavior to validate facility performance and modeling. Some notable grid events that involve large loads are only able to be analyzed and published in reports because of high-speed recording data at or near a large load.

Many large loads—especially data centers and other computational loads—may shift their computational demand to a different physical facility. These shifts may occur in response to changes in factors such as energy pricing, emission intensity, and currency pricing. However, without knowing the exact causes for these shifts and when they will occur, system operators cannot account for the load response or create accurate forecasts, potentially leading them to use more balancing reserves than expected to handle large load power swings.

Long-Term Planning

Large loads must be accounted for in the transmission and resource adequacy planning horizons to reliably plan and operate the grid. Building a new transmission line can take up to 10 years due to permitting, planning, equipment lead times, and construction. With accurate models and studies, planners can ensure that the system is designed to serve the load and maintain resource adequacy.

Demand Forecasting

Large loads pose specific risks to both the short- and long-term demand forecasts. The risks to BPS reliability related to demand forecasting (1+ years) out include the following:

- Under-forecasting the growth of emerging large loads could pose long-term challenges to resource and transmission adequacy.

- Rapid integration of emerging large loads poses challenges to existing assumptions in resource adequacy and transmission planning processes.

Each load by itself may represent a significant portion of both annual energy consumption and peak demand. In aggregate, they comprise even more. In many jurisdictions, the types and volumes of proposed large loads are unprecedented, making them difficult to incorporate into existing forecasting models. As of April 28, 2025, ERCOT had 136 GW of large load in its interconnection queue with energization dates from 2025 through 2030, with a system that has a historic peak of approximately 85 GW. [24]

Estimating the amount of load that will make it from interconnection studies to energization is a challenge for grid planners. As stated before, the primary BPS risks to resource adequacy and transmission planning arise from under-forecasting the growth of emerging large loads.

The arrival and timing of large loads is also frequently uncertain. Some companies engage in "location shopping," exploring and submitting interconnection requests to multiple regions to determine the best location for their operations, creating uncertainty about which projects are firm enough to include in forecasts. Some proposed large loads do not materialize as planned: they may be canceled due to economic and financial challenges or other setbacks. Due to the uncertainty of these large loads materializing, forecasting load for resource adequacy and transmission planning may be much more difficult.

Resource Adequacy

Large loads may also introduce risks to BPS reliability through their effects on resource adequacy. The Virginia Joint Legislative Audit and Review Commission reported that construction of individual data center buildings usually takes 12–18 months.[25] In a 2024 report on generator interconnection timelines, Lawrence Berkeley National Laboratory showed that the median duration from interconnection request (IR) to commercial operations date (COD) is nearly 5 years, with the 25th percentile around 40 months and the 75th percentile around 70 months.[26] As these loads are magnitudes larger than most loads historically seen on the system and proliferating more quickly than most historical load growth, the need for additional generation may not have been planned for, and current system plans may not be able to meet it.

As a result, demand may outstrip generation supply in the near future. Some of this risk may be mitigated if loads are flexible and demand can be reduced during peak hours.[23,23] But, as mentioned above, most computational and other large loads are expected to request firm service. If demand leads to a shortfall of generation and all operating reserves—including controllable loads—are exhausted, manual load shed may be needed to stabilize the system.

Performing resource adequacy assessments and resource planning poses a challenge when the amount of load that may materialize is variable or uncertain, especially when compared to forecasting growth of traditional loads. Planners may model additional scenarios to account for the uncertainty of the magnitude and timing of large loads, but this can lengthen timelines and workloads. This can also cause confusion, as one scenario will ultimately need to be used for planning purposes.

If loads connect within the 10-year *Long-Term Reliability Assessment* (*LTRA*) time frame or five-year adequacy studies, their connections may be unaccounted for when undertaking coordinated planning between regions until the study is updated in the following year.

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[24] "ERCOT Monthly Operational Overview (April 2025)." Accessed: May 30, 2025. [Online]. Available: https://www.ercot.com/files/docs/2025/05/15/ERCOT-Monthly-Operational-Overview-April-2025.pdf

[25] "Data Centers in Virginia," Virginia Joint Legislative Audit and Review Commission, Dec. 2024. Accessed: May 30, 2025. [Online]. Available: https://jlarc.virginia.gov/pdfs/reports/Rpt598.pdf

[26] "Queued Up: 2024 Edition," Lawrence Berkeley National Laboratory, Apr. 2024. Accessed: May 30, 2025. [Online]. Available: https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf

Transmission Adequacy

Transmission adequacy is a well-defined industry concept that is embodied in numerous NERC standards from both the planning and operating perspectives. Large loads can be of a magnitude that must be analyzed well in advance to assess the security of the transmission system and determine whether transmission upgrades are needed to reliably serve the load and meet the expectation of an “adequate level of reliability.”[27] Failure to analyze the impact of the new large load can also lead to real-time transmission system restrictions in the amount of load that can be served.

Part of transmission planning is evaluating the planned system for thermal overloads, voltage criteria exceedances (high and low), and system stability performance against various performance criteria. All problematic findings must be remediated prior to energization to prevent real-time operating reliability risks. Without comprehensive pre-energization analysis and configuration planning, large loads pose potential risks to the reliable operation of the BPS. The larger the load’s peak demand, the greater the risk that it will contribute to an inadequate level of reliability.

From a planning and interconnection perspective, large load interconnection designs are analyzed similarly to large generator interconnection designs. The performance of the transmission system with the inclusion of the large load and its connecting facilities can be defined in general terms as follows:

- The transmission system does not experience instability, uncontrolled separation, cascading, or voltage collapse under normal operating conditions and when subject to predefined disturbances.
  - The performance outcomes are the following:
    - Stable frequency and voltage within predefined ranges
    - No instability, uncontrolled separation, cascading, or voltage collapse
- System frequency is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - The performance outcomes are as follows:
    - Stable frequency within predefined range
    - Facility ratings are respected
    - Frequency oscillations experience adequate damping
- Transmission voltage is maintained within defined parameters under normal operating conditions and when subject to predefined disturbances.
  - The performance outcomes are as follows:
    - Stable voltage within predefined range
    - Facility ratings are respected
    - Voltage oscillations experience adequate damping
- Adverse reliability impacts on the transmission system following low-probability disturbances (e.g., multiple contingences, unplanned and uncontrolled equipment outages, cyber security events, and malicious acts) are maintained at an acceptably low level and, if they occur, are mitigated.
  - The performance outcome is to manage the propagation of frequency deviations, voltage deviations, angular instability, uncontrolled separation, and cascading failures.

[27] “RE: Informational Filing on the Definition of ‘Adequate Level of Reliability,’” NERC, May 2013. Available: https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/ALR%20filing%202013.pdf#search=adequate%20level%20of%20reliability

- Restoration of the transmission system after major system disturbances that result in blackouts and widespread outages of transmission elements is performed in a coordinated and controlled manner.
  - The performance outcome is to recover the transmission system and restore available resources and load to a stable interconnected operating state.

Bulk Electric System (BES) transmission capability is assessed to determine availability to meet anticipated BES demands during normal operating conditions and when subject to predefined disturbances.[28] Additionally, significant demand additions can require a high level of concurrent new transmission buildout as well as many transmission upgrades that require complex and long-term outage coordination evaluations. Delays in completing these new buildouts and projects can result in increased risks to transmission adequacy to serve loads from existing and new generation.

Operations/Balancing

Short-Term Demand Forecasting

Many emerging large loads differ technologically from past industrial loads, leading to significant uncertainty in modeling their behavior and consumption profiles. New loads serve new end uses, such as the parallel training of large language models in AI data centers. This uncertainty results in considerable forecasting errors that could cause system operators to run the risk of under- or over-scheduling, dispatching, or procuring energy and ancillary services. Even after these new loads have been in operation for an extended period, real-time forecasting can remain challenging due to their unpredictable and stochastic nature. For example, high-intensity electrical processing loads like EAFs often experience frequent on-off cycles, causing large, random fluctuations in consumption. Such behavior can lead to dispatch errors, shutting down units prematurely, committing units that are not needed, and generally causing balancing issues. Additionally, large loads are particularly difficult to forecast during extreme conditions, such as during periods of high electricity prices or adverse weather events, amplifying errors in dispatch algorithms when forecasting accuracy is most critical.

Concentrating large loads at single points increases exposure to numerous forecast risks. A single fault could trip the load, from a utility perspective, and amplify the grid disturbance. Moreover, if one of these large loads, such as a data center, is lost and does not return quickly, it can skew the overall forecast and affect transmission station-level forecasts and planning.

Currently, many large loads do not submit real-time or day-ahead operational consumption profiles or plans. This lack of visibility creates forecasting issues, especially for loads with unpredictable consumption patterns, such as data centers or EAFs. Existing short-term forecasting models typically rely on regression-based or autoregressive time series methods that assume past behavior will be replicated in a predictable manner, which fails to account for the dynamic nature of these types of loads.

Load Response to Price and Other Signals

Many large loads may change their demand based on signals like price or emission limits. If the utility is unaware of the triggers that cause the load to change its demand, the utility may not be able to accurately forecast demand. ERCOT analyzed the average percentage of each large load’s curtailment when prices go above specific thresholds, and a handful of loads were highly responsive to prices. Conversely, another handful of large loads curtailed less than half of their demand when prices were high. ERCOT notes that a large portion of its large loads at the time of the analysis were cryptocurrency mining, which is known to be more price sensitive when compared to something like cloud data centers that prioritize uptimes over 99.999%. When the system operators are not aware of these triggers, the forecasting quality may be degraded, which could lead to insufficient reserves.

[28] Reference NERC’s “Adequate Level of Reliability” submittal to FERC: Link

Balancing and Reserves

In real-time power system operations, there must be enough generation to meet demand while maintaining reserves. Failure to maintain this balance could lead to load shed or a system collapse if there is not enough power or if the reserves cannot handle load movement or unit trips.

Large loads, especially PELs, can shift their consumption in seconds, much quicker than conventional generators can ramp. Quick load ramps—increase or decrease—can stress the system, as generation must be rapidly loaded or unloaded in response. These quick real power demand ramps have been observed in the field during normal operations. For example, Figure 3.1 shows a North American data center ramping down from about 450 MW to about 40 MW within 36 seconds around hour 6. The load's demand is constant (around 7 MW) for approximately 4 hours. After hour 10, the data center ramps back up to 450 MW over the course of a few minutes.

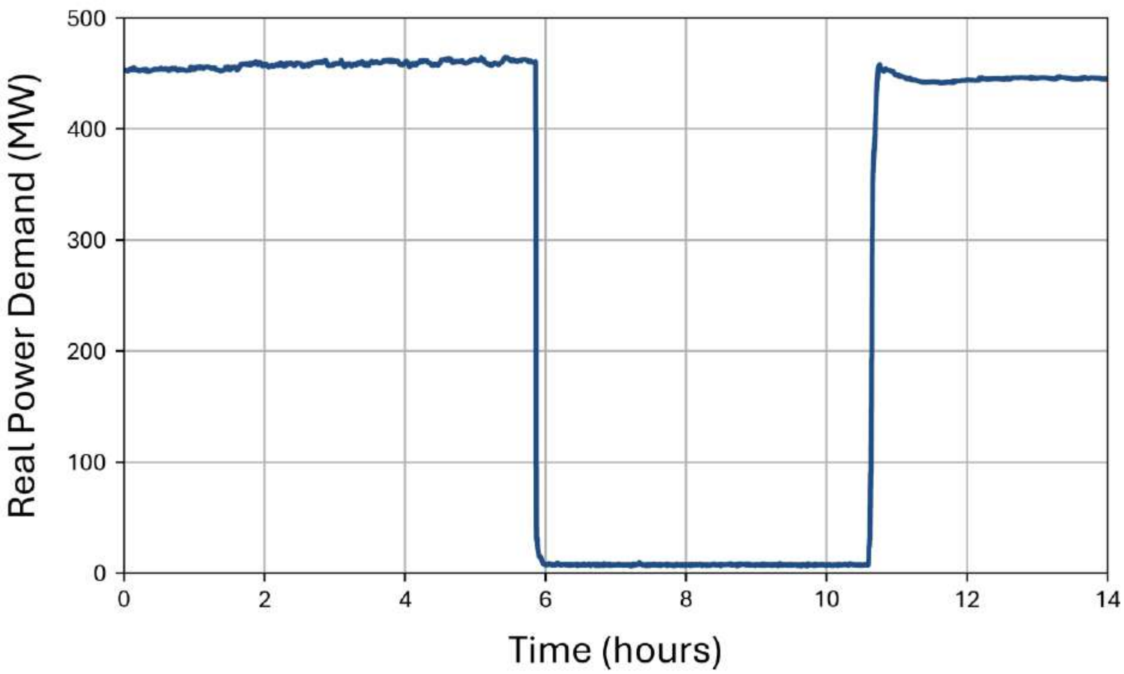

Figure 3.1: Data Center Load Ramp Down and Up

Forecasting these loads to ensure that the system operator procures the appropriate reserves is also a challenge. Without accurate real-time forecasting methods, the system operator may not procure enough energy reserves in the operating day, leading to energy shortfalls and potential load shedding. Loads in operation have already been shown to be flexible, but the signals that affect demand are not known. Without knowledge of the triggers that cause facilities to shift consumption, it will be impossible to properly account for the load behavior in forecasting.

Large load ramp rates may cause issues with frequency regulation by outstripping the reserves held to regulate frequency. These reserves are provided by on-line spinning resources with headroom to manage a decrease in frequency and units that can further lower their output to manage an increase in frequency. With larger ramp rates, more regulation services will be needed to handle larger swings.

In addition to the magnitude of the ramp rates, the timing matters as well. To handle loads that ramp within seconds or minutes and require fast-acting regulation services, system operators typically procure fast-frequency response services to maintain frequency. The case of ramping down may necessitate units that can rapidly shut down.

The system operator will need information on the large load ramp rates to assess the potential magnitude of the ramping problem. Fast ramping of large loads can cause issues with both voltage and frequency regulation.

If the system operator fails to procure adequate regulation to manage frequency, then load shed or rapid generation curtailment may take place and result in unplanned outages, reducing system security/reliability. In addition to the loss of load, the sudden restoration of a large load could exhaust available balancing reserves, ultimately leading to decreased system frequency and potential frequency instability.

Large rapid changes in demand will also rapidly alter the flow of reactive power in the system, potentially exceeding the ability of existing voltage controls to respond and lead to over- and undervoltage conditions. This could lead to the unplanned outages of generation plants initiated by voltage-ride through protection, load loss related to undervoltage load shedding, or even more widespread outages caused by voltage instability and collapse.

Figure 3.2 shows a load ramp down 298 MW within 25 seconds at a cryptocurrency mining facility in North America. The load was exhibiting real power oscillations with a peak-to-peak amplitude of around 25 MW following a load control issue due to an offsite telecommunication failure. The operator instructed the load to decrease its demand, demonstrating the potential for rapid load ramps.

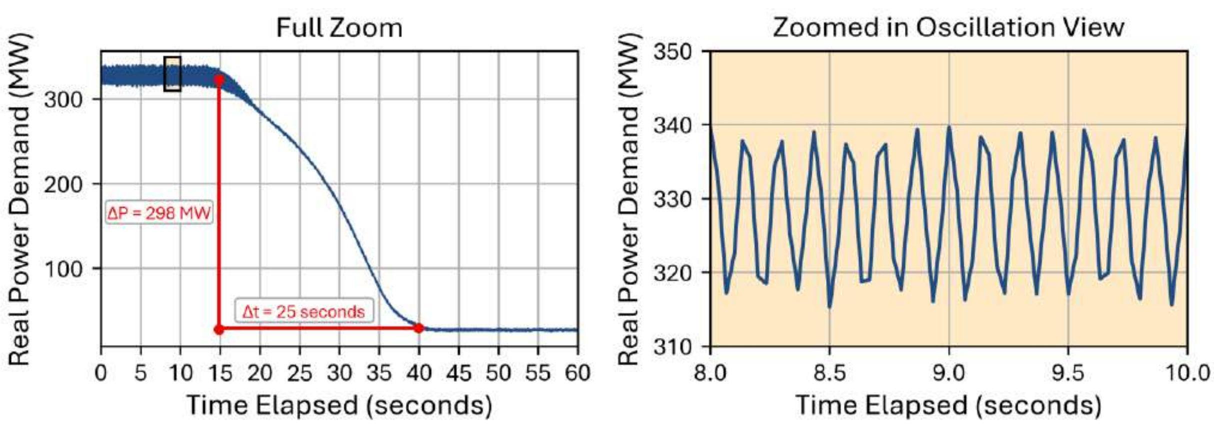

Figure 3.2: Cryptocurrency Mining Facility Load Oscillation and Ramp Down

Lack of Real-Time Coordination

The lack of coordination between grid operators and large load operators creates multiple risks, including those mentioned above, such as load-ramping coordination.

Risks like these may lead to challenges in controlling the area control error (ACE). For example, AI model training at the xAI Colossus Supercomputer in Memphis, Tennessee—currently the world's largest AI training cluster[29]—can change the loading 35–70 MW or more within a minute as the model starts and stops. That change may not be an issue for a single facility, but the aggregate effect across multiple facilities may negatively impact ACE control. These sudden ACE changes may be reflected negatively in the BA Control Performance Standard 1 (CPS1) and BA ACE Limits (BAAL) as required in NERC BAL-001.[30]

The key characteristics impacting real-time coordination for CPS1 and BAAL are: (1) ramp rate (2) peak demand and (3) load predictability. Large, fast, unpredictable ramps from large loads may cause volatility in ACE and BAAL if a BAs

[29] P. Kennedy, "Inside the 100K GPU xAI Colossus Cluster that Supermicro Helped Build for Elon Musk," *ServeTheHome*, Oct. 28, 2024. https://www.servethehome.com/inside-100000-nvidia-gpu-xai-colossus-cluster-supermicro-helped-build-for-elon-musk/
[30] Standard BAL-001-2 – Real Power Balancing Control Performance

generation fleet can't make rapid adjustments. Additionally, if a BAs generation fleet is making rapid adjustments to follow fluctuations in large loads, response reserves could end up being depleted.

There have been documented instances where grid events have unexpectedly impacted data center loads. The NERC *Considering Simultaneous Voltage-Sensitive Load Reductions* incident review[1] details how a 230 kV fault led to customer-initiated simultaneous loss of approximately 1,500 MW of voltage-sensitive load that was not anticipated by the BPS operators. There was a corresponding sudden increase in ACE for the BA when the load tripped. A similar but opposite scenario could occur if a fault at a large load facility adversely impacts nearby generation. The risk to the BPS is unnecessary relay triggering causing potential interactions between the load and generation or the sudden loss of generation and the impacts to ACE control.

Outage Coordination in Operations Planning

Large loads that want to connect within 18 months may also pose risks to outage planning by changing the planning forecast. If the load's connection is approved and there is a resulting increase in load, resource and transmission adequacy margins may be affected. Generation and transmission outages that were approved based on a previous load forecast may need to be shifted or delayed if there is now a resource or transmission adequacy issue based on this increased forecast. This could result in delayed maintenance. Maintenance outages that are taken to avoid sudden tripping (like a failing lightning arrestor) being delayed could increase risks of sudden tripping, which may take longer to repair, leaving the equipment out of service for longer than the original maintenance request. Extended outages on key equipment like generators may affect the system's ability to serve all loads with sufficient operating reserves. Additionally, significant demand additions can require a high level of concurrent generation and pipeline infrastructure development to adequately serve the demand. Delays in completing these new buildouts can result in increased risks to resource adequacy.

BAs must accurately determine their total generation capacity to meet both forecasted and real-time demand. A crucial component of this process is outage coordination. Typically, generators are required to submit their availability, including any deratings, to their BA. This critical information is provided at a minimum in real-time operations and in the near-term horizon. Inconsistent outage coordination between BAs and large load operators can result in inaccurate load forecasts, resulting in either under- or over-committing generation resources. If generation is under-committed, there may not be enough generation to serve all the load. Over-committing generation may cause a different reliability issue related to the mechanical limitations of generation. Thermal units have minimum output levels that can be challenging for them to operate below and may cause undue stress on the unit to come off-line. The risk to the BPS is the potential for inaccurate forecasts and suboptimal generation commitments due to a lack of visibility into large load outages.

Stability

The BPS is planned and operated to be stable as system conditions change and disturbances occur. Potential consequences from power system instability (i.e., a loss of stability) include widespread power outages and permanent damage to BPS equipment. Maintaining stability involves considering a broad range of mechanisms from which instability may arise—**Figure 3.3** illustrates a widely used taxonomy of power system stability problems. Large loads, owing to their high power ratings, fast controls, rapidly varying load profiles, and heavy use of active power electronics, are capable of contributing adversely to any of the stability problems shown in **Figure 3.3**.

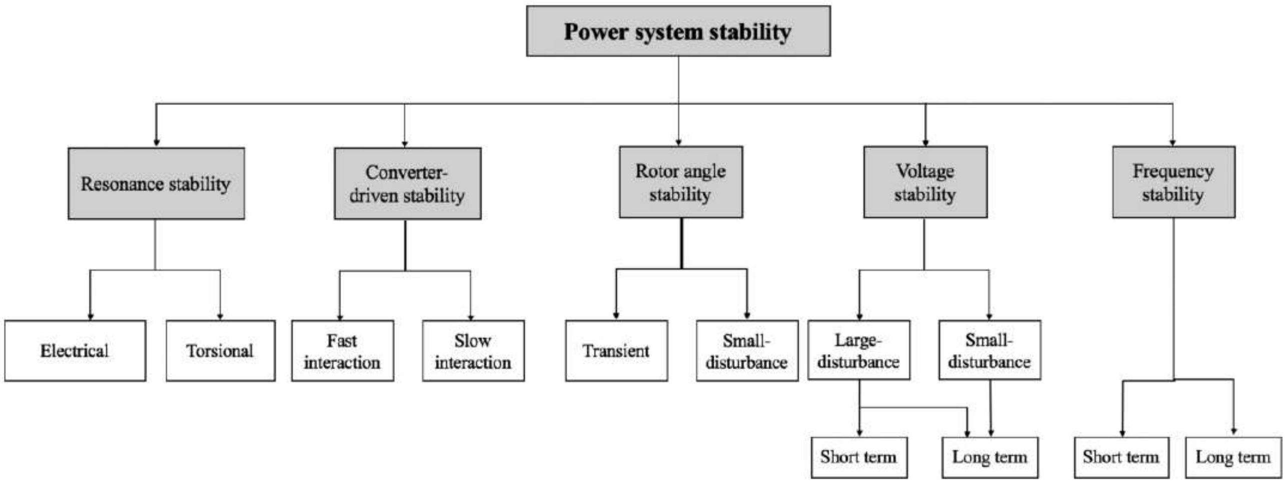

Figure 3.3: Taxonomy of Power System Stability

To keep stability problems from adversely affecting BPS reliability, it is generally necessary to identify them proactively and put mitigations in place to ensure conditions conducive to instability are avoided. Power system stability studies are the primary means by which this is accomplished. Thus, many of the stability-related risks associated with large loads arise from the concern that the loads have not been accurately represented in power system stability studies. This is one reason why the widespread tripping of large loads has attracted significant attention—this widespread tripping was not anticipated in power system studies and could indicate unforeseen (and therefore unmitigated) stability problems. In the next white paper, gaps in current practices (e.g., modeling practices) contributing to this concern will be discussed in detail. This white paper, however, is dedicated to identifying ways in which large loads might contribute adversely to stability problems.

Ride-Through

The voltage and frequency ride-through behavior of large loads during disturbances plays a significant role in how they may contribute to instability. Ride-through behavior is primarily defined in terms of how long the load remains connected during a given voltage and/or frequency disturbance. However, changes in the load's real or reactive power consumption during or after the disturbance are important as well (e.g., how much time passes before a disconnected load reconnects, and how quickly does it return to its original consumption). Currently, much attention is directed toward the tendency of many large loads to disconnect during disturbances. Some large loads have internal protection and control systems that will disconnect from the grid during disturbances. For example, some data centers may switch to backup power systems after three transient voltage disturbances within one minute as observed at certain data centers in the EI load transfer event.[1] The intent behind such systems is usually to ensure the reliability of the large load's process (e.g., serving internet traffic) or protect equipment from damage by switching to a local backup power source.

BPS equipment is designed and operated to meet certain ride-through requirements (e.g., Reliability Standard PRC-024) so that it remains on-line during disturbances and supports the system.[31] These requirements are necessary because disconnecting BPS equipment during a disturbance can worsen the disturbance's effects and, if enough equipment disconnects, lead to cascading power outages. At a sufficient scale, the disconnection of load introduces similar concerns. The tendency of some loads to disconnect during disturbances is not new. However, the scale of recent load loss events was unexpected and had measurable effects on the BPS. This called into question existing modeling practices and expectations for loads.

[31] Standard PRC-024-3

Some large loads have disconnected in large quantities during system disturbances, including the following:

- ERCOT has seen numerous unexpected reductions in consumption or loss of load during disturbances. The majority of losses were with PEL at cryptocurrency mining facilities and oil and gas facilities, which reduced their consumption in response to transmission faults. It was noted that not all facility protections were visible to ERCOT or included in dynamic models. Analysts lacked necessary single-phase high-resolution data as well.
- In the EI, a transmission fault caused the simultaneous loss of approximately 1,500 MW of voltage-sensitive load, primarily from data centers. While circuit breakers at the data center substations did not trip, multiple data centers decreased consumption, switching some of their facility power to backup systems in response to the transient voltage disturbance. **Figure 3.4** shows the loss of data center load in the EI following this fault. The third spike is the third recloser shot at 19:00:39.21 upon which the load tripped.

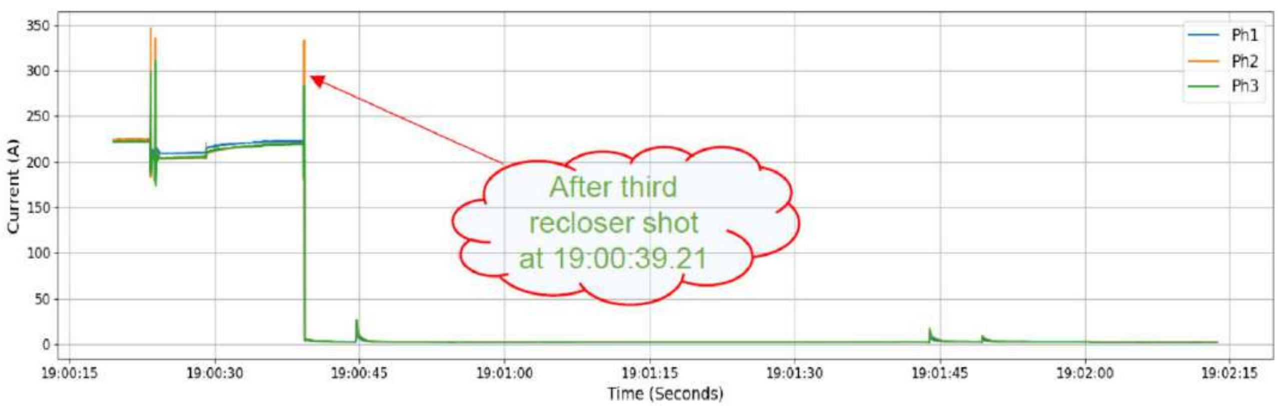

Figure 3.4: Data Center Load Trip

In subsequent sections, stability issues associated with large and sudden load loss are discussed. Ride-through-related challenges are a focal point in many discussions as they are already having an observable impact on BPS dynamics, but there are other stability risks unrelated to ride-through behavior. Power system instability events are often low-probability, high-impact events that require proactive mitigation. Therefore, it is essential to consider potential stability issues unrelated to ride-through, even if they are not yet observed in operations.

Frequency Stability

BPS frequency is maintained at a near-constant value by closely balancing the energy produced by generation resources with that demanded by the load and losses in power system equipment. This is achieved on timescales varying from seconds to years by different processes. Frequency stability risks are associated with the shortest of these timescales and are closely related to operational risks surrounding balancing and reserves. The stability concern is that very large and sudden (e.g., within seconds) changes in the demand from large loads might exceed the ability of fast-acting generation controls to respond and restore balance between generation and demand. As this capacity is exceeded, the frequency deviation will grow larger. Both loads and generation have limits to the frequency deviation that they will withstand before tripping off-line, which may cause further frequency deviations. Thus, the critical reliability concern is that operators may totally lose their ability to regulate the system frequency and large-scale power outages might follow.

When a large load trips, it causes an instantaneous imbalance in load and generation and frequency deviates from nominal. For example, according to NERC's incident review[1] on July 10, 2024, a lightning arrestor failure on a 230 kV transmission line in the EI led to multiple system faults within 82 seconds. These repeated faults resulted in voltage depressions ranging from 0.25 to 0.40 per unit in the affected area. Coinciding with this disturbance, approximately

1,500 MW of load was lost, as demonstrated in **Figure 3.5**—not due to utility disconnection but because of customer-side protection and controls. This sudden load loss caused frequency to rise to 60.053 Hz before it stabilized back to 60.0 Hz within four minutes, as seen in **Figure 3.6**. This incident demonstrates how large-scale load tripping can meaningfully affect BPS frequency. Note that the EI is the largest of the interconnections in terms of inertia and frequency responsive generation capacity—load loss events of a similar size can cause much larger frequency deviations in other interconnections (e.g., a ~235 mHz rise in the ERCOT Interconnection).

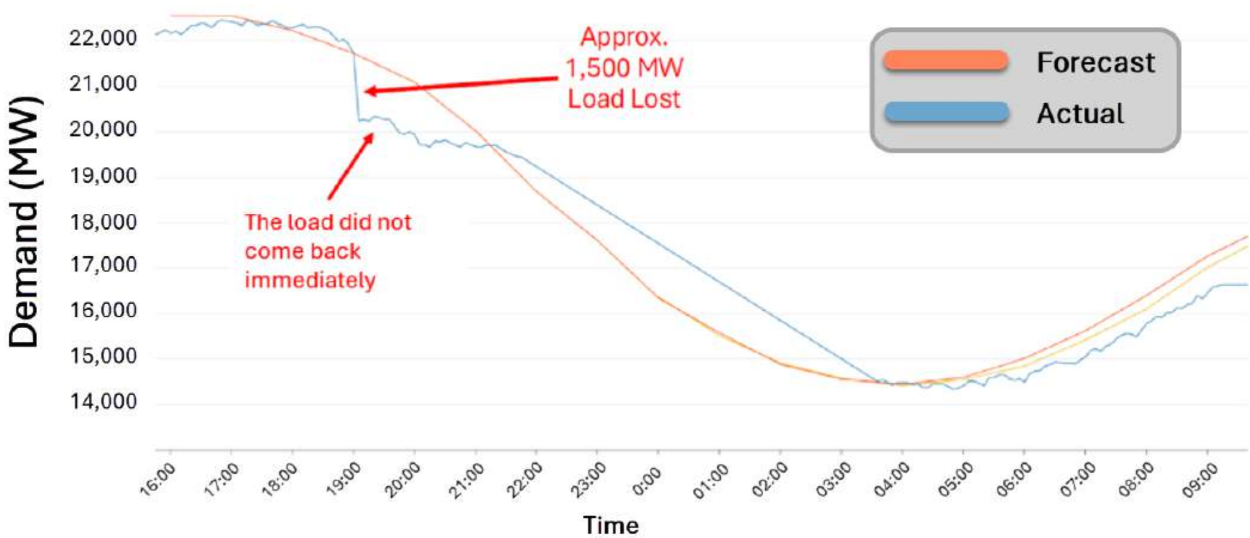

Figure 3.5: System Load Chart[1]

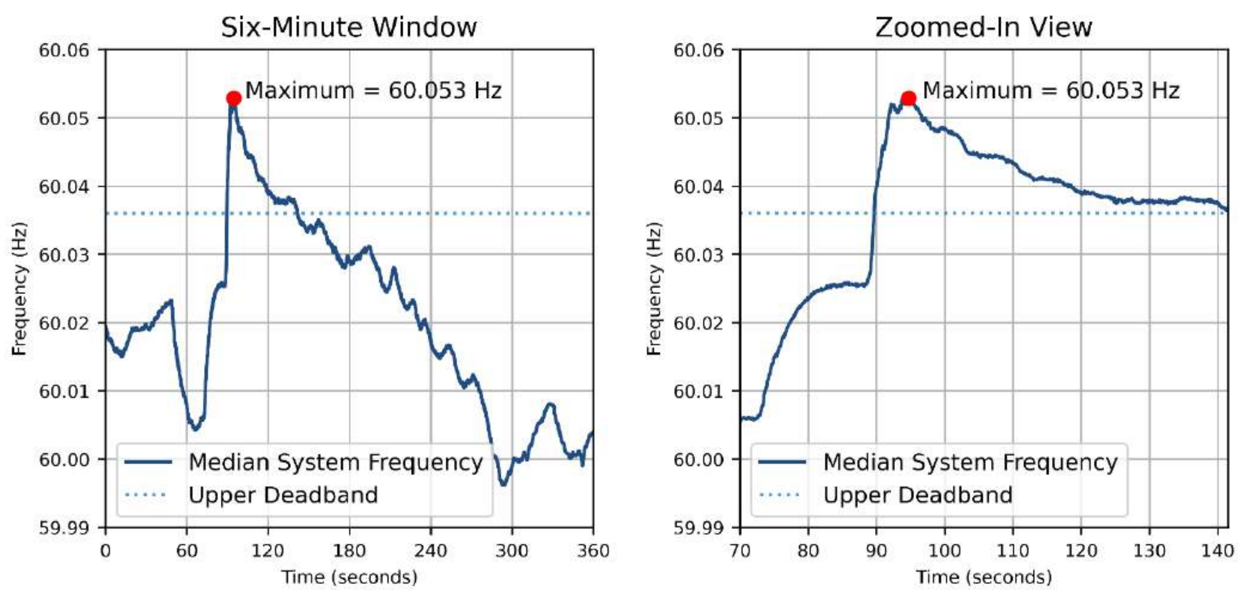

Figure 3.6: Frequency Plot for Eastern Interconnection 1,500 MW Large Load Loss/Transfer on July 10, 2024 (Provided by University of Tennessee: Knoxville)

Generators are prone to damage from overfrequency conditions as an increase in system frequency corresponds to an increase in the generator's mechanical speed as well. For this reason, BPS generators are equipped with overfrequency protection. Large load tripping may also result in subsequent generation tripping initiated by overfrequency protection. The tripping of generation will aid frequency stability and mitigate overfrequency conditions, and so the primary concern is not necessarily that frequency would increase indefinitely. Rather, the concern is that the subsequent loss of generation could initiate other reliability issues. Generator overfrequency protection is designed to protect generators from damage during extreme disturbances—it is not designed as a method for fast frequency control or to prevent blackouts. Thus, generation overfrequency tripping that follows large load tripping may cause line overloads, voltage regulation issues, or even a subsequent underfrequency event. All these issues have the potential to cause further operation of protection systems. With each protection system operation, more BPS equipment is taken out of service, and the possibility for cascading outages grows.

The known behaviors of large loads indicate that there is the potential for many gigawatts of large load to be lost nearly simultaneously, leading to the overfrequency issues discussed previously. There are other ways in which large loads could cause frequency stability issues. If many large loads energized at the same time, they could cause significant underfrequency events. This could cause other loads to be tripped off-line via underfrequency load-shedding schemes. If enough large load energizes and is not tripped off-line, the frequency may become low enough that generators trip off-line due to underfrequency protection. If this occurs, frequency instability and widespread outages are a serious possibility as each generator that trips off-line further reduces the system's ability to halt the decline in frequency.

Rotor Angle Stability

Large loads introduce rotor angle stability risks primarily as a result of their potential to cause gigawatt-scale changes in BPS real power flows within a few electrical cycles (50 milliseconds in a 60 Hz system). Of the two forms of rotor angle stability (transient and small signal), these characteristics are more relevant in the context of transient rotor angle stability, which is the primary focus of this section. Rapid changes in real power flows cause synchronous generators to experience power swings, wherein generator power outputs oscillate for a time. The greater the change in real power flows, the greater the magnitude of the resultant power swings. If the power swings become too large, the generators become entirely unable to control their output power or frequency (i.e., they lose synchronism) and must be immediately tripped offline or they will be seriously damaged. The portion of the BPS affected by a particular loss of synchronism event can vary greatly, and consequences range from the outage of a single plant to the islanding of large sections of an interconnection.

There are several ways in which known large load behaviors can adversely affect rotor angle stability:

- **Exacerbated postfault power swings:** BPS faults often cause generators to accelerate rapidly until the fault is cleared. Postfault, the energy consumed by loads provides much of the "braking" force that eventually reverses this acceleration and prevents a loss of synchronism. Thus, if large loads trip off-line during the fault and do not resume consuming energy after the fault is cleared, generators may be unable to halt their acceleration and rotor angle instability may result. This is shown below in **Figure 3.7**, where a large load is tripped in a positive-sequence dynamic stability simulation. Note that multiple generators lose angular stability in seconds.
- **Unexpected violations of stability-related transfer limits:** If there is too much electrical distance between generators and the loads they serve, the generators may lose synchronism. In terms of system requirements, this manifests as stability-related power transfer limits on transmission lines. This becomes a problem in the context of large loads because the sudden tripping of many large loads can lead to almost instantaneous gigawatt-scale shifts in net power exchange for an area. From a stability perspective, the problem is that the nearby generators, being unable to decrease their real power output quickly enough to account for the loss of load, will begin transferring real power to loads further away. This can lead to sudden and unexpected

violations of stability-related transfer limits, in which case the generator(s) near the large loads will lose synchronism.[32]

- **Reduced stability margins due to generator reactive power absorption:** Most BPS equipment and most kinds of load consume more reactive power than they produce, and BPS generators supply a significant portion of the BPS's reactive power needs. Some large loads, in contrast with traditional loads, produce reactive power (i.e., they are capacitive loads and operate at a leading power factor). This is because the active power electronics commonly used in LEL operate at roughly unity displacement power factor and are equipped with filters[33] that, while primarily intended to attenuate switching noise and harmonics from the electronics, also produce reactive power. While this can benefit the BPS by improving voltage regulation and reducing transmission system losses, it can worsen rotor angle stability. This is because synchronous generators are more prone to rotor angle instability when absorbing significant amounts of reactive power.[34] Unless this excess reactive power production is accounted for in studies, the available stability margin may be overestimated, leading to field events where generators become unstable unexpectedly.

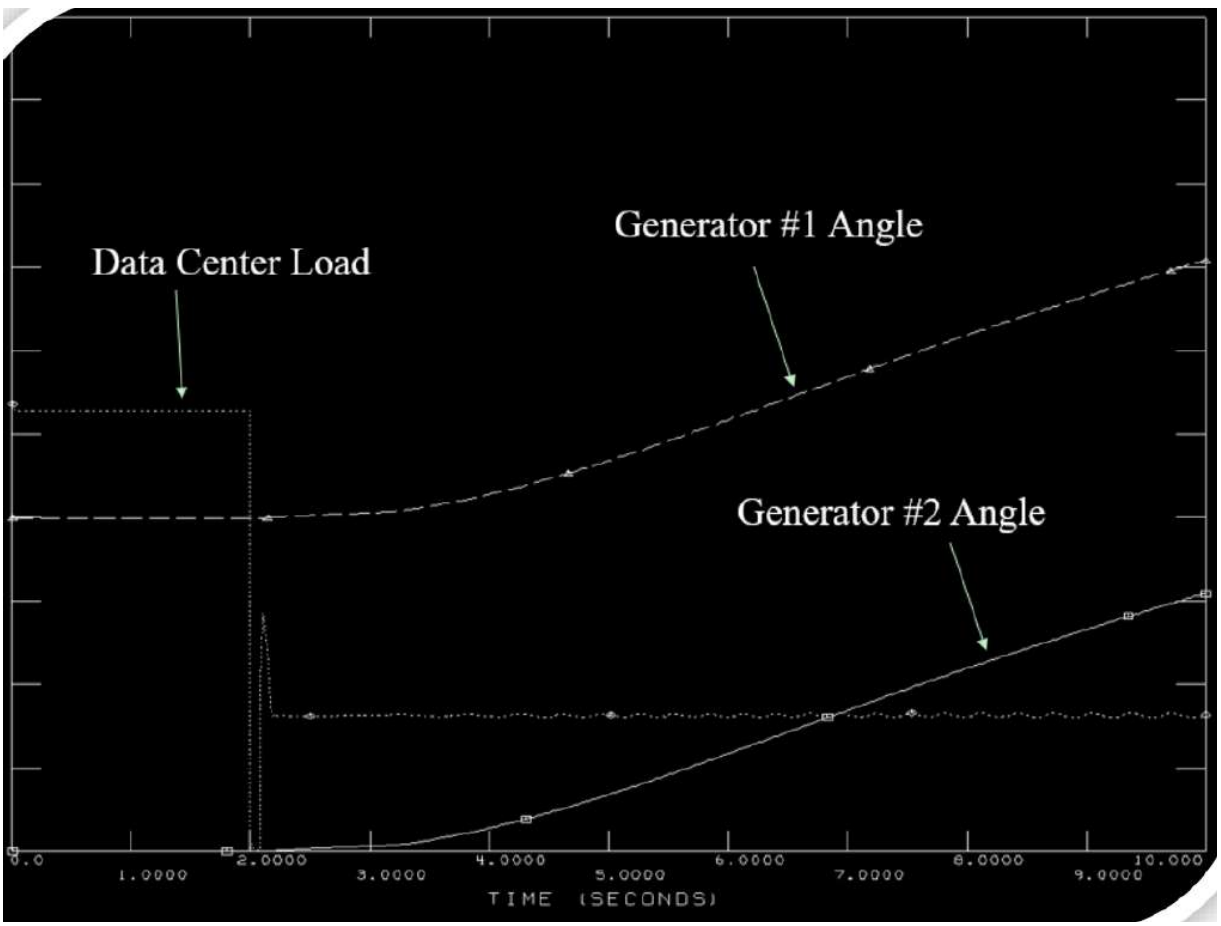

Figure 3.7: Simulation Showing Generators Losing Angular Stability Following Nearby Data Center Load Trip

[32] M. Peterson, "Data Center Interconnection Studies & Challenges," presented at the Large Loads Task Force Meeting and Workshop, Apr. 2025, pp. 53–65. Available: https://www.nerc.com/comm/RSTC/LLTF/LLTF_April_Meeting_&_Technical_Workshop_Presentations_.pdf

[33] Some of these filters are separate devices but some are built into the power electronics themselves (i.e., they would not be visible in a single-line diagram).

[34] Absorbing reactive power is achieved by reducing the generator's internal voltage. This necessitates operating at a higher power transfer angle to deliver a given quantity of real power, reducing angular stability margin.

The first two issues arise from the ride-through issues discussed previously. The third arises from the unusually high penetration of active power electronics in large loads. In all three cases, shortcomings in stability models are the primary source of risk. All three issues relate to the unique properties of large loads, which may not be captured in existing models or studies. Stability issues cannot be reliably avoided if they cannot be identified, and models and studies are an essential tool for identifying reliability issues.

Rotor angle stability risks are especially relevant for new generation plants being sited near large loads. In some cases, the siting of new generation near large loads is motivated by a need to defer or avoid transmission system upgrades. The same transmission constraints that prevented the large loads from being served by existing generation are likely to adversely affect the generation plant's ability to maintain synchronism with the rest of the BPS.

Apart from risks related to transient rotor angle stability, there does exist the possibility for large loads to affect small-signal rotor stability. Small-signal rotor angle stability problems relate to the generators' ability to successfully damp out small power swings and is the main form of stability that power system stabilizers (PSS) are designed to address. Just as active power electronics devices such as STATCOMs may be used to intentionally act as PSS and improve the damping of power swings, it is possible that the active electronics present in large loads might unintentionally lessen the damping of power swings. The risk of this depends highly on the control design of the active power electronics used in large loads. These can vary significantly by vendor and their inner workings are often protected intellectual property. The risk of small-signal rotor angle stability issues involving a large load are higher if the load is connecting at a location where power swings are more poorly damped.

Voltage Stability

Large loads can affect voltage response and stability, with possible impact on transmission and generation elements, including tripping. While low voltage is generally the focus for voltage collapse, overvoltage issues could result in instability; this has occurred on at least one system.[35]

Transient (Short-Term) Voltage Stability

Transient voltage stability refers to the ability of the BPS to support system voltages by maintaining adequate dynamic reactive power support following large disturbances. Typically, this time frame captures up to 30 seconds after the disturbance. The ramp rate, peak power consumption, and voltage sensitivity are all major factors in the transient time frame of voltage stability. The larger and faster the difference in real and reactive power consumption is during the transient time frame, the greater the risk to the BPS voltage stability. This could be brought on by a load rapidly ramping up or down. Additionally, this rapid change in power demand could be caused by a planned or unplanned instantaneous tripping of the load. Loads with more sensitivity to low or high voltages will carry increased risk of sudden trips, which can lead to voltage instability.

As demonstrated by an ERCOT voltage stability study,[36] risks to BPS voltage stability may occur if enough load trips off-line in response to faults. The primary characteristic of large loads that cause this risk is ride-through behavior. As shown in the NERC *Incident Review on Simultaneous Voltage-Sensitive Load Reductions*,[1] certain fault conditions can cause many electrically close loads to trip or reduce demand.

Mid-Term Voltage Stability

Mid-term voltage stability refers to the ability of the BPS to transition from the transient time frame (less than 30 seconds) to the multiple-minute time frame during which system load and generator response should have stabilized. During this period, numerous factors are in play. Voltage instability arises in this time frame when system reactive demands cannot be met by dynamic and static reactive resources with the applied control schemes (e.g., automatic

[35] T. Van Cutsem and R. Mailhot, "Validation of a Fast Voltage Stability Analysis Method on the Hydro-Quebec System," IEEE Trans. on Power Systems, Vol. 12, No. 1, pp. 282-292, February 1997.
[36] ERCOT, "Load Loss Threshold Analysis", presented at the ERCOT Large Load Working Group (LLWG) Meeting, May 2025. [Online]. Available: https://www.ercot.com/files/docs/2025/05/19/Large_Load_Loss_Analysis_051625_LLWG.pptx

generator controls, dynamic reactive resource control, controlled shunt devices, and on-load tap changers) and unacceptably low voltage or voltage collapse ensues. Large loads may pose a risk to the mid-term voltage stability of the BPS depending on their ramping behavior, peak load, and overall variability.

Steady State (Long-Term) Voltage Stability

Long-term voltage stability refers to the system's ability to maintain steady voltages once a new operating state is reached, typically well beyond the transient time frame. The magnitude of increase and decrease of real and reactive power informs the amount of risk to voltage stability. The larger the magnitude in change, the greater the risk of steady-state voltage instability. Large loads with the largest peaks and troughs in demand may affect the long-term voltage stability of the system more as compared to smaller loads or less variable loads.

Resonance- and Converter-Driven Stability

The risks associated with large loads and both resonance- and converter-driven stability have many facets in common, and they are discussed together here to avoid unneeded repetition. Both kinds of stability risk involve the closed-loop controls used in large load electronics interacting with other power system equipment. Any closed loop control has limitations regarding the kinds of signals to which it can respond effectively, and the deployment of power electronics in large loads may uncover limitations that were of little or no consequence when the same electronics were used in smaller quantities and for different applications.

For resonance stability, the concern is that large loads will significantly decrease the damping of resonances, or oscillatory modes, in the BPS. These resonances may be electrical (e.g., those introduced by series-compensated transmission lines), mechanical (e.g., turbine torsional modes). Whenever a disturbance occurs in the grid, some oscillation occurs at these resonant frequencies. When the system is stable, the energy associated with the oscillation is absorbed by a mix of generators, loads, and power system equipment, and the oscillation quickly decreases in amplitude. In the context of resonance stability, the concern is that the controls in the large load's electronics will respond by *supplying* energy to the oscillation, instead of absorbing it. Depending on how much energy the large load contributes, the oscillation may increase in duration or even begin to grow in amplitude over time (i.e., the system will become unstable).

The term "converter-driven stability" was introduced to categorize some stability problems that are associated with converter-interfaced generation but not with traditional synchronous generation. Many of the active power electronics devices used in large loads are capable of exhibiting the same converter-driven stability problems as converter-interfaced generation. Converter-driven stability problems can involve interactions between different power electronics and, given the large variety of power electronics designs in use, the possible behaviors and scenarios are many. One form of converter-driven stability that has significantly impacted grid reliability before is weak system stability, an issue associated with the phase-locked loops used by many active power electronics (including those used in large loads). Such controls can become unstable at low short-circuit ratios (e.g., 2 or less). In 2019, an 800 MW offshore wind plant in Great Britain experienced a weak grid instability issue and tripped offline,[37] eventually contributing to an outage affecting over 1 million customers.[38]

Regardless of whether resonance- or converter-driven stability is involved, the potential for the large loads to cause issues is primarily determined by the control algorithms used in the active power electronics. This introduces the same challenge as that associated with small signal rotor angle stability—control algorithms in power electronics vary significantly by make and model, and the control details needed to accurately model the device's potential to interact

[37] Y. Cheng *et al.*, "Real-World Subsynchronous Oscillation Events in Power Grids With High Penetrations of Inverter-Based Resources," in *IEEE Transactions on Power Systems*, vol. 38, no. 1, pp. 316-330, Jan. 2023, doi: 10.1109/TPWRS.2022.3161418.
[38] Energy Emergencies Executive Committee, "GB POWER SYSTEM DISRUPTION – 9 AUGUST 2019," Department for Business, Energy, and Industrial Strategy, Sep. 2019. Available: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/836626/20191003_E3C_Interim_Report_into_GB_Power_Disruption.pdf

with grid dynamics are usually protected intellectual property. That said, some risk factors relevant in the case of known stability issues may be relevant for large loads as well.

Some trends from known converter-driven and resonance stability issues might indicate which large loads are at a higher risk of being involved in similar problems. Broadly speaking, the resonance and converter-driven stability issues are more common when a large concentration of power electronics devices is located close to a generation plant (traditional or inverter-based), series compensated line, or other large concentration of power electronics devices (e.g., a STATCOM or HVdc line). The stability issues are usually most prominent when the components involved are more weakly coupled with the rest of the BPS (e.g., they are connected through only a single transmission line). This tends to correspond to a low short-circuit ratio (relative to the size of the large load).

Forced Oscillations

In the context of resonant stability, the concern was that the large load's power electronics cause existing oscillatory modes in the power system to become less damped and potentially unstable. In such cases, the large load is not the source of the oscillation—it is responding to an oscillation that is a natural result of the power system's dynamics. However, there are also cases where large loads can be a source of oscillations and introduce related reliability risks. In such cases, where the large load acts as a relatively fixed source of an oscillatory signal (e.g., voltage magnitude, real power), the load is producing a forced oscillation.[39]

Broadly speaking, the reliability risks associated with forced oscillations are not always well defined. In some cases, they may cause accelerated aging of BPS equipment (generators in particular) or the operation of protection systems (especially those designed to detect unstable oscillations). In such situations, the concerns generally arise because the frequency of the forced oscillation is the same as that of an existing oscillatory mode in the power system. There are some known risks in such cases, which will be the focus of this section.

If the forced oscillation does not happen to be near the frequency of any known oscillatory modes, it becomes difficult to define specific reliability risks. That said, unexpected interactions involving oscillations have been responsible for well-known reliability issues, such as the Mohave generator shaft failures of the 1970s (caused by subsynchronous resonance, a kind of resonance stability problem) or the 1996 blackouts in the Western Interconnection (which involved an unstable interarea oscillation). The BPS was not designed to operate with large and persistent subsynchronous oscillations, and their presence heightens the risk of unintended interactions that could result in power outages and/or BPS equipment damage.

Some large loads can produce forced oscillations at frequencies below 60 Hz (i.e., subsynchronous frequencies). These oscillations can occur either as a natural byproduct of the load's end use or as the result of unexpected control interactions (i.e., load equipment is not behaving as designed/intended). AI data centers can have load profiles that are periodic, repetitive, and sustained in nature (see **Figure 3.8**). More traditional large loads, such as EAFs, can also exhibit sustained subsynchronous oscillations as a natural byproduct of the arcing process.

[39] Energy Systems Integration Group's Stability Task Force, "Diagnosis and Mitigation of Observed Oscillations in IBR-Dominant Power Systems," Energy Systems Integration Group, Aug. 2024. Available: https://www.esig.energy/wp-content/uploads/2024/08/ESIG-Oscillations-Guide-2024.pdf

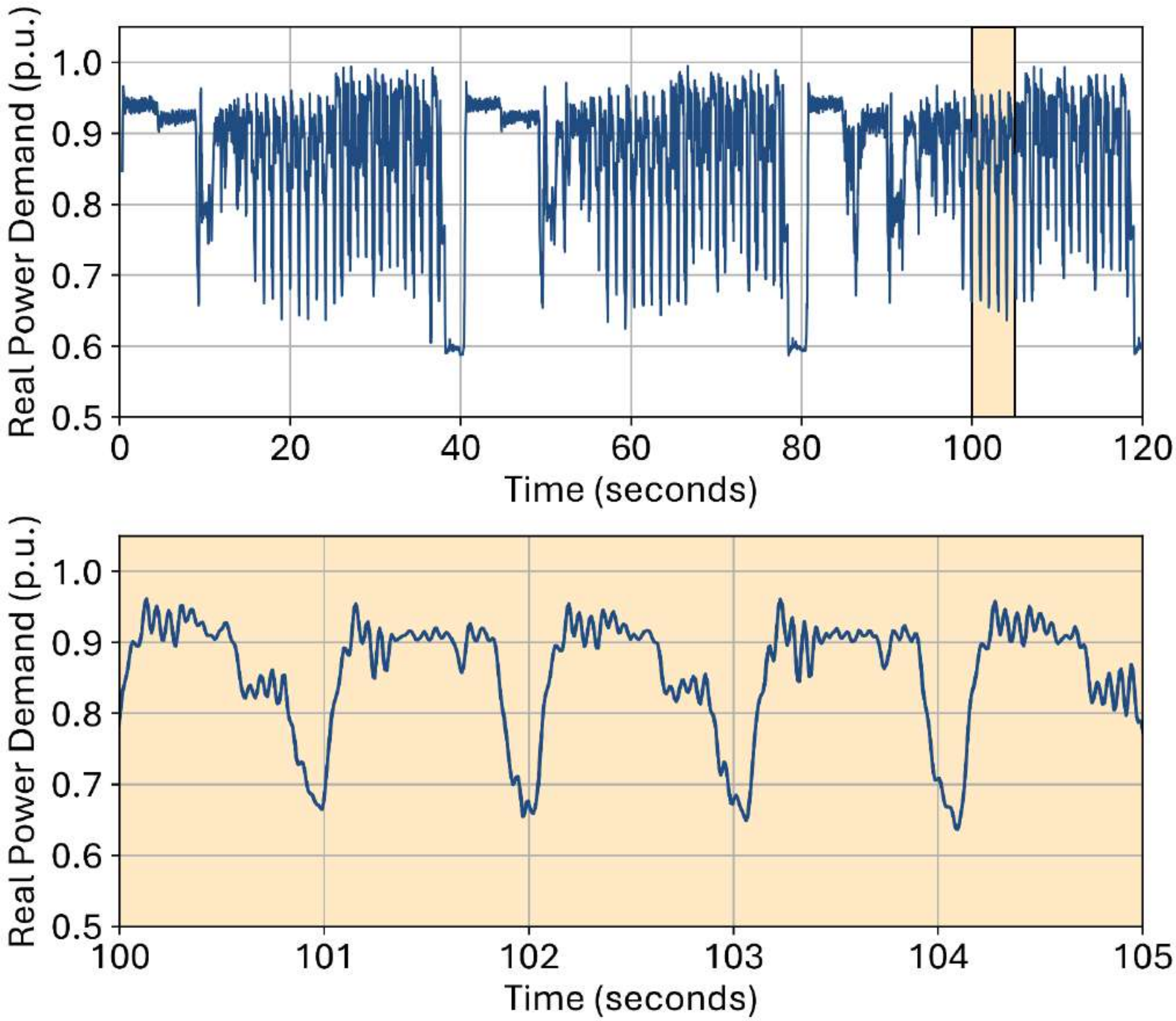

Figure 3.8: Example AI Data Center Load Profile During Training Over Two Minutes (Top) and in a Five-Second Period (Bottom)

Forced oscillations can also arise from unintended control issues involving large load equipment. In 2023, a large data center in the Midwest produced forced oscillations unexpectedly. A 1 Hz forced oscillation occurred when a natural frequency was stimulated by periodic forcing of a slower frequency (see **Figure 3.9**). The system was inadvertently perturbed at one-second intervals by active power electronics at a data center. Each perturbation resulted in a relatively well-damped 11 Hz ringdown.[40]

[40] L. Zhu, E. Farantatos, and L. Chen, "Sub-Synchronous Oscillation Detection and Analysis – Dominion Case Study," presented at the Sub-Synchronous Oscillations (SSO) Workshop, Accessed: Jun. 07, 2025. [Online]. Available: https://www.epri.com/events/539b60d7-57da-4252-9968-fb1754ee3b66

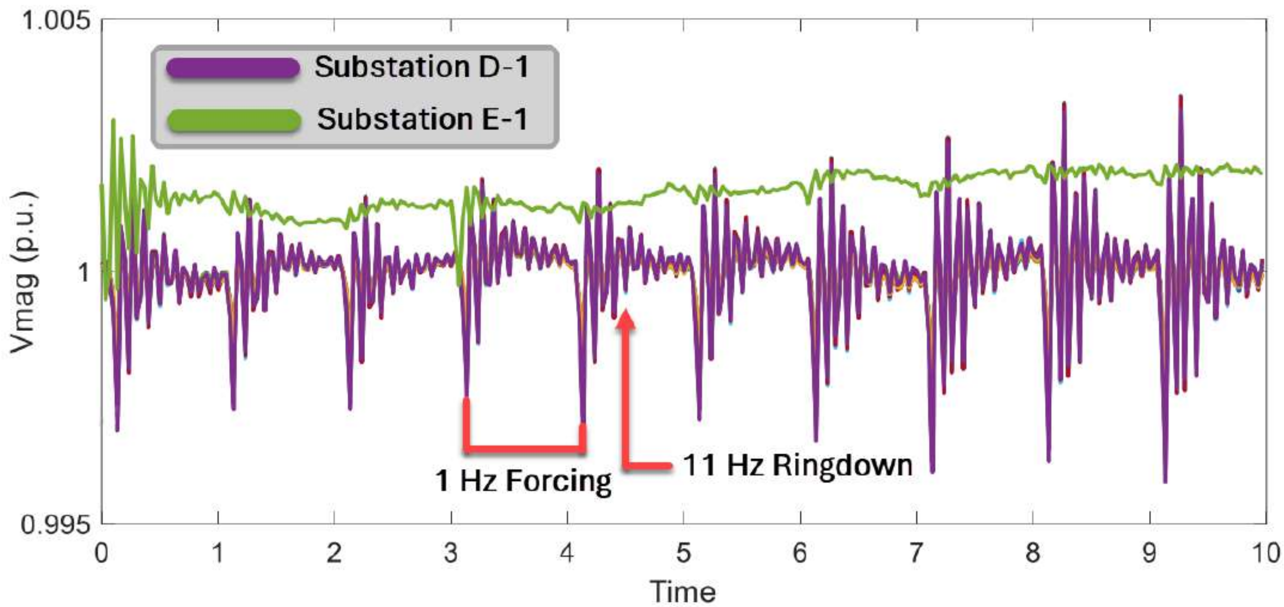

Figure 3.9: Field Measurement of Forced Oscillations Occurring at 1 Hz[40]

Forced oscillations that occur at modal frequencies present a heightened reliability risk (compared to forced oscillations at other frequencies) because they propagate more effectively—either across the BPS or into specific components such as the blades or shafts of large turbines.

Forced oscillations at interarea modal frequencies can affect an entire interconnection. In 2019, a steam turbine in Florida created a forced oscillation with an amplitude of 200 MW and a frequency of 0.25 Hz.[41] The EI has an inter-area mode with a frequency of roughly 0.25 Hz, and this mode is excitable from the Florida region.[42] Because of this mode, the oscillation spread far across the EI, and oscillations at large as 50 MW were observed in New England. The oscillation persisted for 18 minutes and no outages or damage were reported. However, if the oscillation were larger in magnitude, it may have affected a larger portion of the EI. Depending on the location where the large load is connected and frequency of oscillations it produces, forced oscillations produced by a large load could interact with interarea modes in much the same way and pose risks for a large portion of the interconnection they are connected to.

Forced oscillations at the torsional modal frequencies of a turbine-generating units (steam and gas turbines, specifically) can cause persistent, large torque pulsations (e.g., 30% peak-to-peak) and fatigue the turbine, aging it more rapidly. As an example, **Figure 3.10** illustrates the torques produced in a steam turbine by the acceptance of two different prospective EAF loads.[43] In the left-hand plot, the EAF characteristic (not shown) does contain significant oscillations, but these occur at frequencies other than the torsional frequencies of the turbine-generating units. Consequently, these oscillations do not propagate very effectively into the turbine and generate little torque ripple beyond an initial transient. In the right-hand plot, however, the EAF's oscillations correspond to one of the turbine-generator's modal frequencies and significant torque pulsations are apparent, even in steady-state.

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[41] NERC, "Eastern Interconnection Oscillation Disturbance Forced Oscillation Event," NERC, Jan. 2019. Available: https://www.nerc.com/pa/rrm/ea/Documents/January_11_Oscillation_Event_Report.pdf

[42] Interarea modes are generally most excitable from locations near the edges of the interconnection and less excitable from regions near the center.

[43] Torsional Resonance Identification in Turbine-Generator Shaft Due to the Operation of Electric Arc Furnaces at Steel Mills in Bangladesh Power System

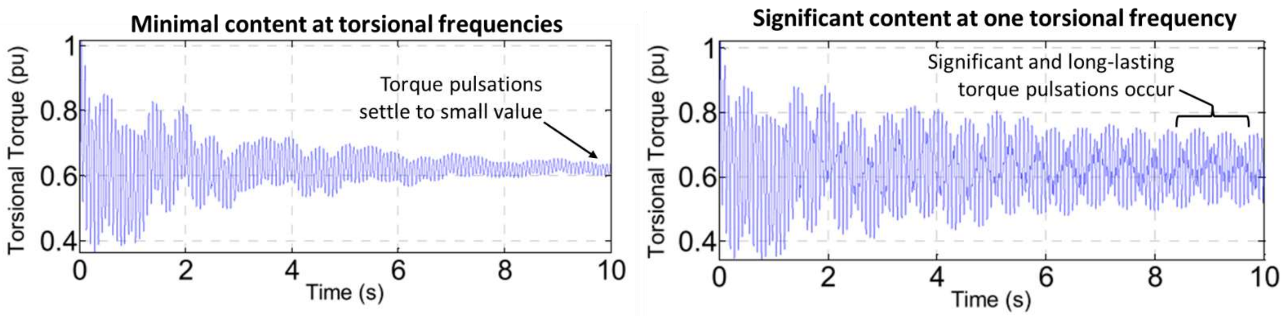

Figure 3.10: Torques Produced in a Steam Turbine for EAF Loads That Do Not (Left) and Do (Right) Contain Frequency Content at the Steam Turbine's Torsional Modal Frequency

As with resonance and converter-driven stability, the risks associated with forced oscillations from large loads are higher when the large load is located near a kind of device known to participate in stability problems, as well as when the large load's short-circuit ratio is low. The same list of devices (generators, capacitors, concentrations of power electronics) is relevant. Forced oscillations involving regional or interarea modes are a special case; studies or measurements must be used to identify the excitability of the modes at buses throughout the BPS. Risks associated with forced oscillations are higher at buses where modes are more excitable,[44] and modes with lower damping coefficients are more likely to introduce reliability issues if excited.

In the Dominion system, oscillations have been seen arising from the interaction of data centers' UPS input units.[45] These oscillations could also interact with nearby inverter-based resources and complicate system stability.

Power Quality

Depending on the operating performance, large loads can have relatively low energy consumption while idling and then have sudden demand spikes when expected to operate. The extensive use of power electronics-based devices could make data centers a significant source of harmonics, unless filtering is designed to address those harmonics. During the transition to these higher-power pulses, the system may experience even higher harmonic distortions, voltage fluctuations causing flicker (visible, frequent changes in the brightness of lights), unbalances, or general power quality issues.

Harmonics

Traditional large industrial loads are known to be a key source of harmonic current injections into utility systems. EAFs employ power-electronic-rich devices such as rectifiers and variable speed drives, which are unbalanced and variable loads. This can lead to significant harmonic current injections, as illustrated in the example harmonic spectrum for an EAF in **Table 3.1**. In addition, inter-harmonics from these loads have the potential to excite torsional modes of nearby fossil and nuclear generation, which can damage turbine shafts.

[44] Western Interconnection Modes Review Group, "Modes of Inter-Area Power Oscillations in the Western Interconnection," WECC, 2021. Accessed: Jun. 09, 2025. [Online]. Available: https://www.wecc.org/sites/default/files/documents/meeting/2024/Modes%20of%20Inter-Area%20Power%20Oscillations%20in%20the%20WI.pdf

[45] Mishra, Chetan & Vanfretti, Luigi & Jr, Jaime & Purcell, T & Jones, Kevin. (2025). Understanding the Inception of 14.7 Hz Oscillations Emerging from a Data Center. 10.13140/RG.2.2.19971.82720. Available: https://www.researchgate.net/publication/389098360_Understanding_the_Inception_of_147_Hz_Oscillations_Emerging_from_a_Data_Center

Table 3.1: Example Harmonic Spectrum of an EAF	
Harmonic Order	**Magnitude (% of Fundamental)**
2	8.9
3	5.7
4	3.0
5	3.7
7	2.1

Large loads such as data centers are a source of harmonics due to extensive usage of power electronics in both their IT (e.g., UPS, power supplies) and cooling (variable speed drives) components. **Figure 3.11** illustrates the excessive voltage harmonics distortion caused by a data center facility and the impact of a harmonic mitigation solution. As shown in the figure, voltage distortion was greatly reduced once harmonic mitigation measures were implemented for the system.

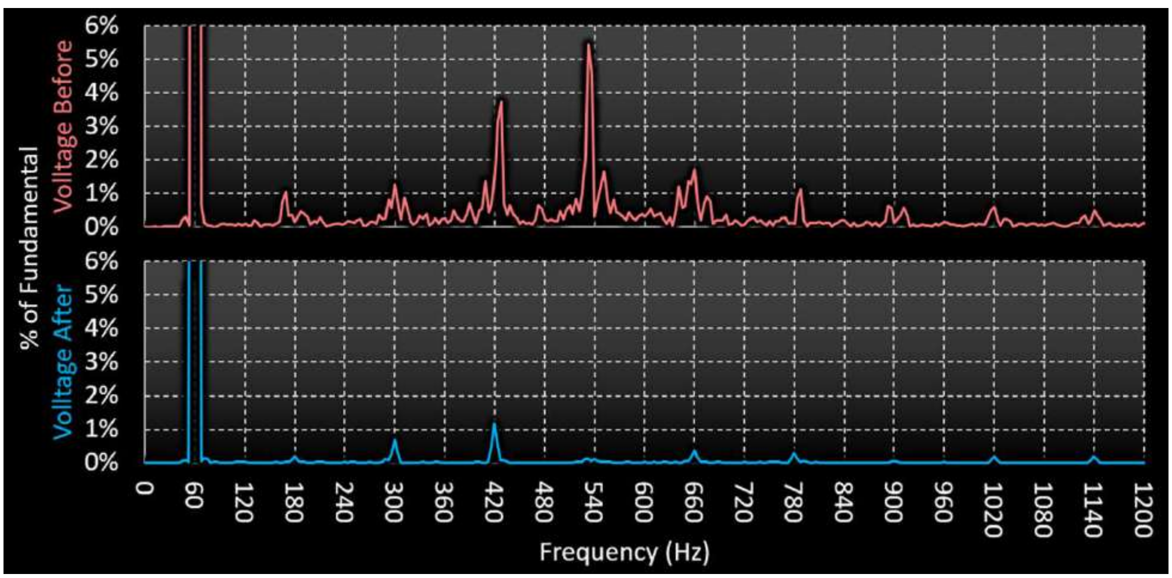

Figure 3.11: Voltage Distortion Before and After Harmonic Correction for a Data Center Facility

Some other large loads may have a variable frequency spectrum that must be accommodated for multiple operating scenarios. **Figure 3.12** provides the harmonic spectrum of a medium-frequency induction furnace (MFIF) for both starting and normal operations. Frequency spectrums will often change depending on factors including the operating mode, system configuration, and capacitor switching.

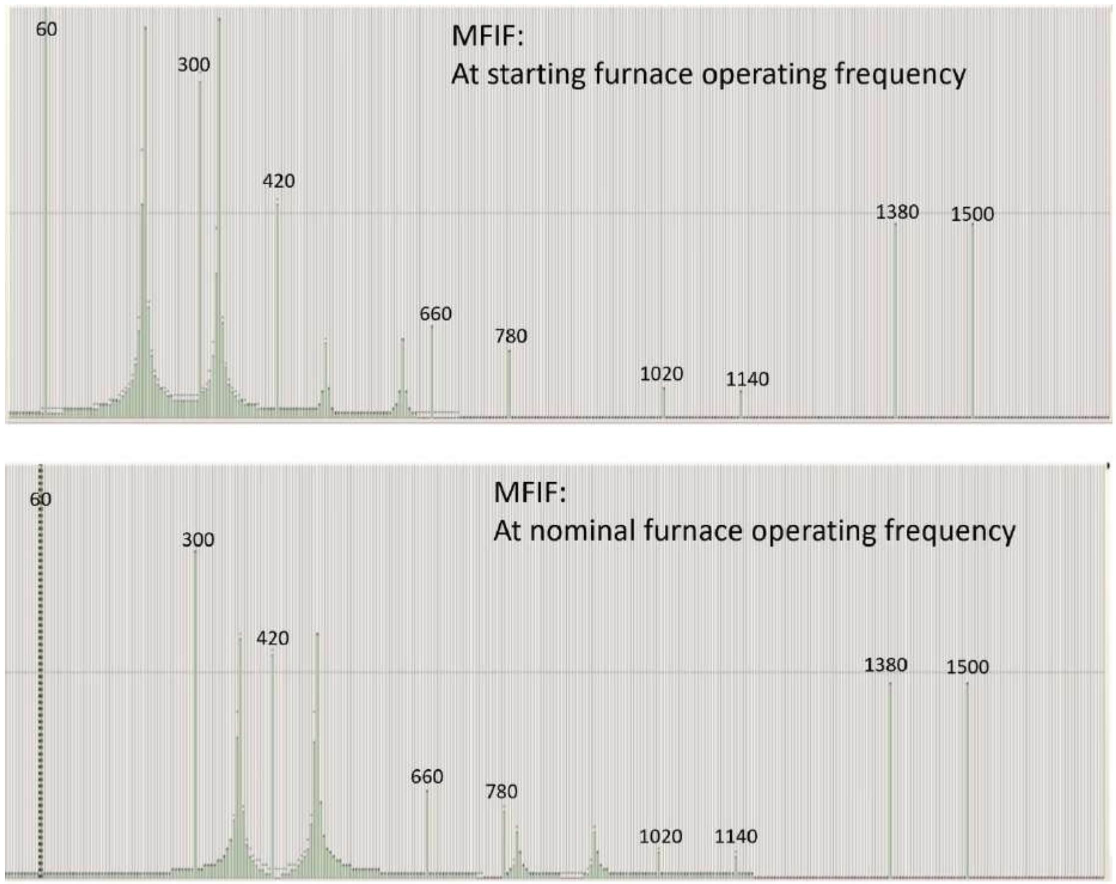

Figure 3.12: MFIF Current Spectrum for Starting and Normal Operation

Voltage Fluctuations

Traditionally, persistent voltage fluctuations resulting in excessive flicker have been a concern with large industrial loads with fluctuating power demand, such as EAFs and welders. **Figure 3.13** shows an example demand profile illustrating high variability in power demand of an EAF.

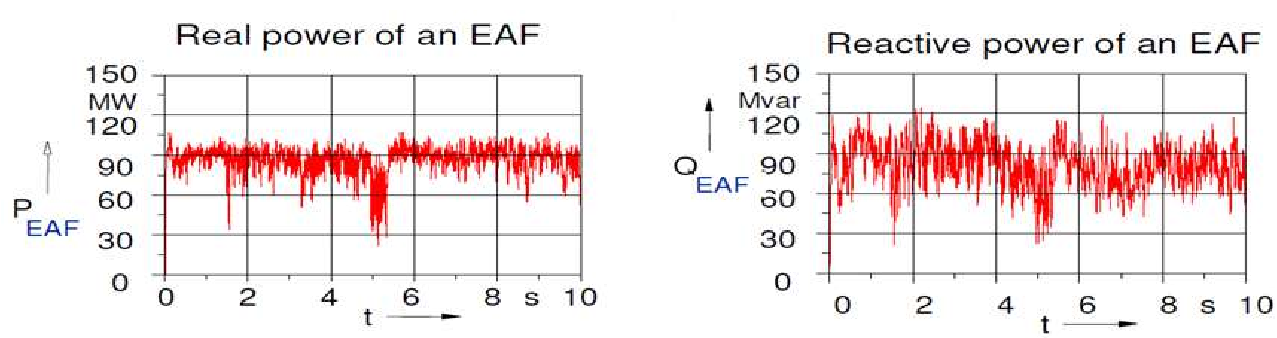

Figure 3.13: Load Profile of an Electric Arc Furnace

Some new large electric loads, such as cryptocurrency miners and AI data centers, also have the potential to introduce significant voltage fluctuations to the supply system. This can be attributed to the significant variation in the load profile of these loads. An example variable load profile of an AI data center is shown in **Figure 3.14**. This can be an issue, for example, when these loads are concentrated in regions where background flicker is already high (i.e., low system margin) and these new loads contribute to push the overall flicker above the acceptable values. **Figure 3.15** shows an example of a data center load pulse where the doubling of the load caused voltage distortion and flicker issues for those connected to the facility.

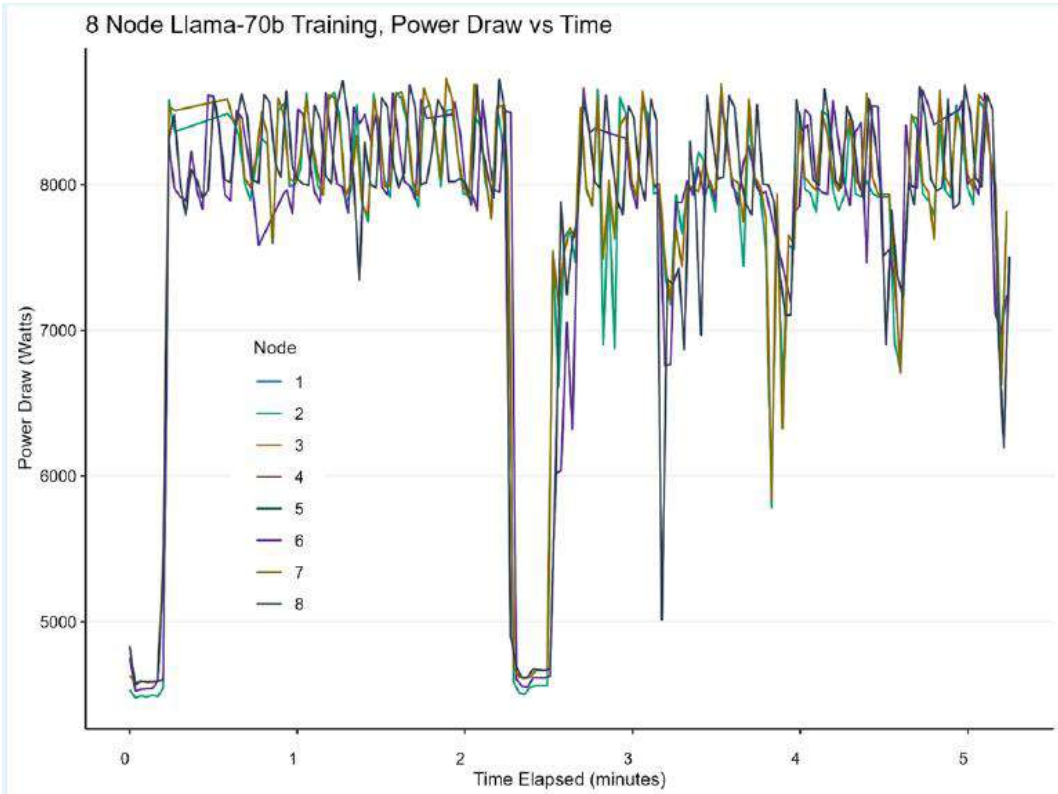

Figure 3.14: AI Training Load Profile Example

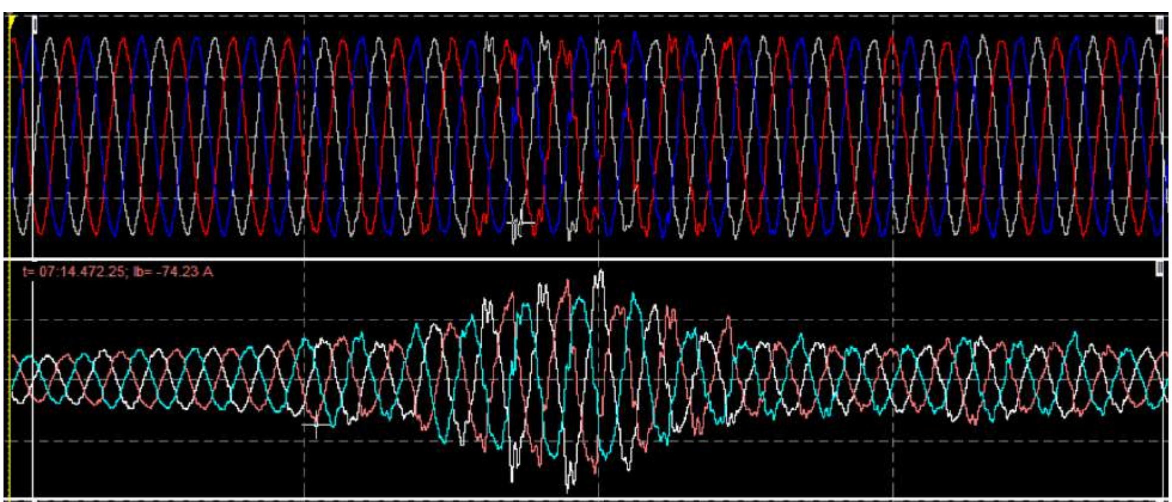

Figure 3.15: Data Center Load Pulse (Top: Voltage; Bottom: Line Current)

Voltage Sags and Transients

Voltage sags associated with normal system fault clearing have been known to result in tripping of large load facilities. In addition, transient events associated with capacitor or reactor switching in power systems have also been known to result in unnecessary tripping of large loads, resulting in significant system impact.

Physical and Cyber Security Risks

Cyber Security

This section focuses on theoretical situations and the likelihood of these sorts of attacks are not explored in this paper. The primary cyber security risks to BPS reliability from large loads are bad-actor control of large load demand (e.g. tripping or rapid ramping) and loss of critical communications between a large load and the utility.

It has been shown that some of the latest large loads may exceed 1 GW at a single site. Bad-actor control of a single site that large could affect BPS reliability. If a bad actor has control of the large load, they may be able to control the demand. The risks associated with fast ramping and sudden tripping of large loads are discussed in prior sections of the paper (e.g. Operations/Balancing and Stability).

Loss of communication between the large load and utility could cause similar issues to bad-actor control of the load. If the utility loses visibility of the large load or communications with the large load operators, it could negatively impact operations, balancing, and stability.

Load-Shedding Programs and System Restoration

Manual Load-Shed Obligation Impacts

TOs and TOPs are required to maintain load-shed and under-frequency load shed (UFLS) programs. As large loads are integrated to the system, they may add to the owner's UFLS obligation, eventually reaching a point where the owner must shed all its residential load but still cannot meet load-shed obligations. Tripping the large load could shed more load than intended, risking the stability of the system.

Automatic Under-Frequency Load-Shedding Programs

UFLS programs are the last line of defense for BPS reliability. If frequency declines below preset thresholds, and Transmission Owners have exhausted all preplanned manual load shedding options (i.e., rotating blackout), UFLS programs automatically shed load to arrest the frequency decline and stabilize the system.

Although the PRC-006-5 automatic UFLS standard calls for having a certain amount of load under automatic control to be shed, the rapid addition of large loads makes it even more important to ensure that the automatic UFLS programs are up to date and can address the presence of the new large loads on the system. The current procedure of evaluating UFLS programs every five years may not be often enough. These large loads present a risk that the local distribution system may not contain enough load to cover the UFLS requirements. TOs may need to start including load at the transmission system to meet the requirements of PRC-006.

The functionality of this "last-resort system preservation" program is assessed through studies that identify the electrical islands that may be formed under simulated conditions. The studies are used to establish the parameters of the UFLS entity automatic UFLS programs as required by the standard.

System Restoration

System restoration (blackstart) is the worst-case scenario for everyone who relies on the electric grid, especially for system operators who must restore the grid as quickly and safely as possible. Fortunately, system operators have existing procedures and train annually for this scenario.

Blackstart is an iterative process that relies on either starting a blackstart resource or building out from intact islands to re-energize transmission lines and restore load while maintaining frequency and voltage within acceptable limits. When starting from blackstart resources, transmission lines and loads are brought online iteratively, creating a small electrical island. Multiple islands are gradually connected until the entire grid is re-established. Appropriate load pickup is critical to successful restoration from a blackstart resource because small islands are more sensitive to small changes creating larger swings in voltage and frequency. It is crucial to consider the effects of cold load pickup during this process. If frequency swings too low during the load pickup, it could cause the blackstart resource or other generators to trip. The blackstart resource and other generators should be dispatched near the middle of their real power capability range to allow room to increase or decrease generation to control frequency. Additionally, high voltages could also lead to generators tripping, causing the island to collapse. A summarized example blackstart procedure is listed below.

1. First, small amounts of load (10–15 MW) are restored in a particular island.
2. As islands are stabilized (more transmission lines, more load, more units connected in the same island), the operator reviews the feasibility of connecting two islands together.
3. If connection is successful, more transmission lines, load, and units are added to the now-growing island. If not, the smaller islands must be rebuilt.
4. An island may black out even prior to connecting with another island. The most likely cause in those cases is the addition of too much load at one time—a distinct possibility in the world of new large loads.

System operators prioritize the restoration of loads based on their function, size, and location. Loads are restored in blocks that are limited by the size of the blackstart generator on isochronous control and, eventually, constant frequency control.

Two other load characteristics can affect the system restoration process as loads are restored: segmentation and demand variability. In the case of large loads, the total load of a customer may need to be portioned into smaller, manageable and predictable segments for restoration. A lack of clear, pre-determined segmentation agreed between load customer and TSP during the restoration state can cause frequency decline or voltage collapse. This can trigger UFLS and crash the island or create the need for load shed. The same is true when a restored load increases its demand without system operators' instruction.

Typically, the system operator has had finer control of load segmentation on the distribution and transmission system. However, large loads with internal segmentation raise the risk of restoring too much load too fast.

Chapter 4: Conclusion

As emerging large loads seek to swiftly interconnect to the BPS, they pose new risks to the BPS. Many current large load constructs are based on transmission facility ratings with no additional accounting for the potential impact that large loads may have on the BPS. If large loads are defined by a single number, many in the sector would choose 50 or 75 MW. However, additional characteristics should be considered in any definition of large loads. This white paper shows that in addition to peak demand, many other characteristics of emerging large loads affect their impact on BPS reliability. These characteristics include fast interconnection timelines, demand profile, load predictability, ramp rate, PELs, voltage sensitivity, and internal segmentation. In addition to the characteristics of the load, the system characteristics also affect what a "large load" means. Frequency stability depends heavily upon interconnection-wide properties like inertia and on-line generation. These interconnection-wide characteristics vary greatly in North America. Additionally, risks like voltage instability may be more dependent on local system properties, like available reactive power from nearby equipment.

Large loads pose risks in both the planning and operations horizons. Their quick interconnection timelines and large peak demands drive generation and transmission adequacy risks. The fast ramp rates and variability of the loads could exhaust reserves for balancing and contribute to voltage and frequency instability. If system planners and operators lack accurate dynamic models, they may be unable to predict ride-through and system behaviors during events. Much of the PEL load can contribute to harmonics and voltage fluctuations. Large loads like data centers can also be susceptible to cyber-attacks that could trigger load ramps. Additionally, the rapid pace of load integration with large loads' magnitude could negatively impact system resilience. Large loads must be considered in load-shed obligations, UFLS program design, and blackstart restoration.

To understand how these risks align with the unique characteristics of large loads discussed in this white paper, see **Appendix B: Comparison of Characteristics and Risks**.

Given the multitude of risks posed by large loads, it is recommended that the risks be prioritized in the order shown across the following three tables. NERC's Framework to Address Known and Emerging Reliability and Security Risks states that prioritization of risks is accomplished through analysis of their exposure, scope, and duration as well as impact and likelihood.

High-Priority Risks	
Long-Term Planning	Resource Adequacy
Operations/Balancing	Balancing and Reserves
Stability	Ride-through
	Voltage Stability
	Angular Stability
	Oscillations

Medium-Priority Risks	
Operations/Balancing	Short-Term Demand Forecasting
	Lack of Real-Time Coordination
Long-Term Planning	Demand Forecasting
	Transmission Adequacy
Stability	Frequency Stability
Security Risks	Cyber Security
Load Shedding Programs & System Restoration	Manual Load-Shed Obligations
	Automatic UFLS Programs

Low-Priority Risks	
Power Quality	Harmonics
	Voltage Fluctuations
Load Shedding Programs & System Restoration	System Restoration

Finally, NERC would like to formally thank all the industry experts, from utilities, regulators, national labs, government agencies, and data center developers/operators/owners, who contributed to this white paper. The names of individual contributors and their organizations are provided in **Appendix C: Acknowledgements**.

Appendix A: Large Load Construct Data

Table A.1: Summary of Large Load Constructs			
Region/Entity	**Threshold**	**Rationale**	**Classification**
ERCOT	75 MW	Above 75 MW, a transmission upgrade is likely needed to serve the full load.	Peak Demand
NYISO	10 MW at 115kV or above, or 80 MW below 115kV	These loads could impact the New York state transmission system and need to be evaluated to determine their responsibility for upgrades required to reliably interconnect to the NY State Transmission System.	Peak Demand and Voltage Level
Dominion	100 MW	Above 100 MW, a ring bus configuration is needed per Facility Interconnection Requirements.	Peak Demand
Grant PUD	2 MVA for large, and 40 MVA	2 MVA is the largest secondary service transformer and 40 MVA is the largest transformer size available and requires additional or new substation work. Above 40 MVA may require transmission service.	Peak Demand
Portland General Electric	1 MW, 30 MW	The primary drivers are rate and cost allocation. At 1 MW or greater, there can potentially be an impact on feeder mainline or substation vs. a simple line extension for smaller load. Load at 30 MW aligns with the typical distribution substation transformer loading criteria.	Peak Demand
PacifiCorp	1 MW	Currently driven by tariffs.	Peak Demand
SRP	10 MW, 150 MW	At 10 MW or greater a dedicated substation off of 69 kV system is required. At 150 MW or above, a 230 kV connection is needed.	Peak Demand

Appendix B: Comparison of Characteristics and Risks

Table B.1 shows a mapping of potential large load characteristics to the risk that it causes or is related to. Large loads can be categorized, as shown in **Chapter 2:**. It should be noted that each large load may have a unique mix of characteristics. Additionally, each characteristic may have different thresholds for causing risks depending on the system and local area it connects to.

Table B.1: Large Load Characteristics and Risks Mapping

Risks	Characteristics								
	Peak Demand	Fast Interconnection Timelines	Demand Profile	Load Predictability	Ramp Rate	Load Type (PEL)	Voltage Sensitivity (Ride-through)	Inaccurate Dynamic Models	Internal Segmentation
Inaccurate Long-Term Forecasts	X	X		X					
Steady State Thermal and Voltage Violation	X		X	X	X		X		
Insufficient Generation Adequacy	X	X		X					
Inaccurate Short-Term Forecasts			X	X	X	X	X		
Balancing Reserves Shortage		X	X	X	X	X	X		
Voltage Instability	X		X		X	X	X	X	
Frequency Instability	X				X		X	X	
Oscillations			X	X		X		X	
Harmonics			X			X			
Insufficient UFLS Procurement	X	X							X
Insufficient Load Shed Obligations	X	X		X					
Loss of Blackstart Islands				X			X		X

Appendix C: Acknowledgements

This white paper was developed by a significant number of contributors from the NERC LLTF. The LLTF would like to acknowledge and thank the following individuals for their support in drafting this white paper.

Table C.1: Contributors

Name	Company
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads

NERC Large Loads Working Group White Paper

March 2026

RELIABILITY | RESILIENCE | SECURITY



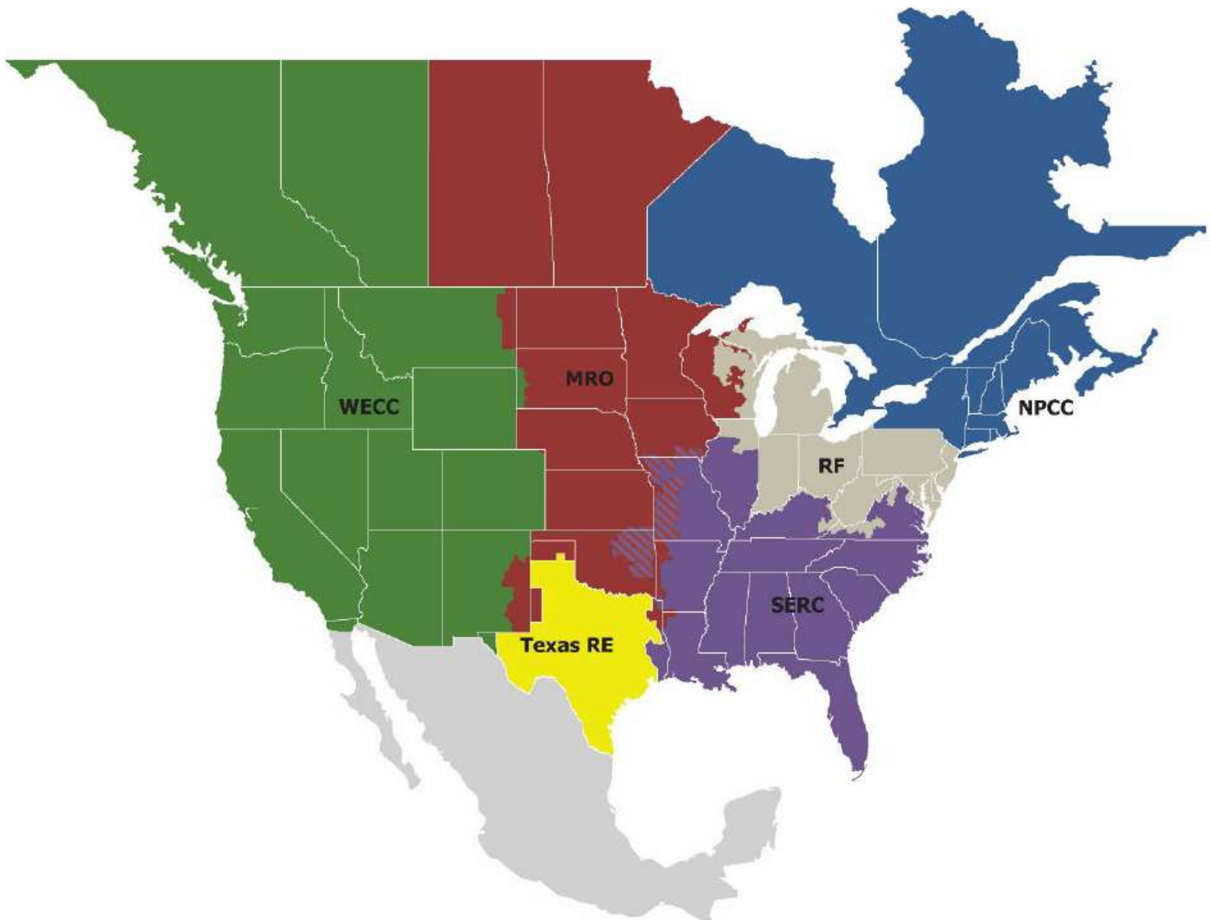

Table of Contents

Preface

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

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is made up of six Regional Entities as shown on the map and in the corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Regional Entity while associated Transmission Owners/Operators participate in another.



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

Executive Summary

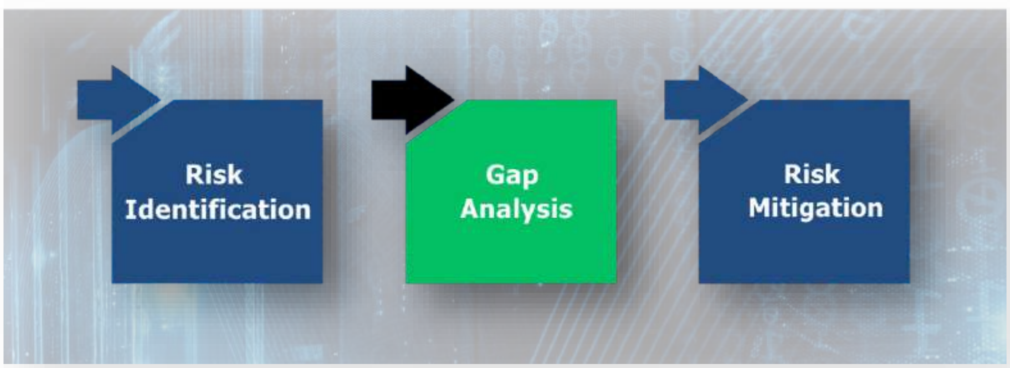
A New Challenge on the Horizon

As the North American electric system evolves, emerging large loads are challenging the reliability, resilience, and security of the North American bulk power system (BPS).[1] These large load facilities are rapidly increasing in number, scale, and operational complexity, creating challenges under existing NERC Reliability Standards, interconnection practices, and system planning assumptions that were not designed to account for their unique characteristics.

NERC's Response

Large load facilities are rapidly increasing in number, scale, and operational complexity

To respond to this evolving landscape, NERC commissioned the Large Loads Working Group (LLWG)[2] of NERC's Reliability and Security Technical Committee (RSTC) to identify potential gaps related to large load[3] integration in Reliability Standards, interconnection requirements, and Institute of Electrical and Electronics Engineers (IEEE) Standards,[4] as well as in utility practices like load forecasting and load modeling practices. This paper comes after previous work that outlined the characteristics of large loads and identified the reliability risks they may present to the BPS.



NERC's *Assessment of Gaps in Existing Practices, Requirements, and Reliability Standards for Emerging Large Loads* evaluates gaps related to the following:

- **Interconnection processes and requirements**
- **Planning and resource adequacy**
- **Balancing and operations**
- **Disturbance ride-through, stability, and power quality**
- **Security**
- **Resilience and event analysis**
- **Load modeling**

[1] Glossary of Terms Used in NERC Reliability Standards
[2] In December 2025, the Reliability and Security Technical Committee promoted the Large Loads Task Force to a working group.
[3] See Chapter 1 for the definition of "large load" for this paper.
[4] IEEE Standards are voluntary and must be adopted by a governing body to become enforceable. By contrast, NERC Reliability Standards are developed for the purpose of becoming mandatory and enforceable on users, owners, and operators of the BPS in North America.

Furthermore, this white paper categorizes the risks to the BPS related to large loads to determine the appropriate mitigations.

…existing Reliability Standards and the existing processes and requirements related to BPS planning, operations, security, and other areas are inadequate to address the risks posed by emerging large loads

Overall, this white paper finds that the existing Reliability Standards and the existing processes and requirements related to BPS planning, operations, security, and other areas are inadequate to address the risks posed by emerging large loads that are forecasted to make up a significant portion of the future grid. This inadequacy exists because the regulatory regime was established at a time when most significantly sized loads had different operating characteristics when compared to the data center or cryptocurrency mining and other emerging large loads currently seeking interconnection.

Building a Strong Foundation

This paper serves as a foundational step in updating industry practices to address the challenges of integrating large loads into the evolving electric grid. Alongside the Large Loads Task Force (LLTF) *Characteristics and Risks of Emerging Large Loads* white paper,[5] it performs Step 1 of the RSTC Standard Authorization Request (SAR) Process.[6] The RSTC or others may[7] consider developing SARs or other mitigating measures to mitigate the reliability gaps discussed in this paper.

Essential Insights: Key Reliability Recommendations

The following provides a summary of the LLWG recommendations based on the gaps assessed in this paper. The detailed list of recommendations can be found in the **Conclusion**.

- ✓ **Recommendation 1:** There are multiple high-impact risks to the BPS from large loads that NERC registered entities[8] cannot adequately address. The LLWG recommends that NERC pursue registration of a type of entity (or types of entities) that is able to perform specific functions to address the risks.[9]

- ✓ **Recommendation 2:** The LLWG and other groups should propose SARs to address the unmitigated risks to the BPS related to emerging large loads.

- ✓ **Recommendation 3:** The LLWG should identify potential mitigations to risks posed by emerging large loads through improvements to existing planning and operations processes and interconnection procedures for large loads as planned for the LLWG's work item titled *Reliability Guideline: Risk Mitigation for Emerging Large Loads*.

- ✓ **Recommendation 4:** Registered entities should coordinate and collaborate with large load entities and update their practices to address the gaps discussed in this paper.

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[5] Available here: White Paper Characteristics and Risks of Emerging Large Loads
[6] Available here: RSTC SAR Development Process clean Sept 20 2023.pdf
[7] *Ibid. See also*, the NERC Rules of Procedure regarding submittal of SARs.
[8] See NERC Rules of Procedure Appendix 5A and NERC Rules of Procedure Appendix 5B for more information on registered entities. Available here: Rules of Procedure
[9] The findings of the NERC Level 2 Alert: Large Load Interconnection, Study, Commissioning, and Operations, distributed on September 9, 2025, will likely help provide more information regarding the need to pursue registration of an entity type (or types of entities).

- ✓ **Recommendation 5:** To address the gaps discussed in this paper, Transmission Owners (TO) should coordinate with other registered entities as applicable to update their interconnection requirements; Planning Coordinators (PC) and Transmission Planners (TP) should update their interconnection study processes.

- ✓ **Recommendations 6-8:** The NERC Load Modeling Working Group should work to address the applicable gaps identified in this paper. Additionally, the Security Working Group and the System Protection and Control Working Group should further assess applicable gaps and propose mitigations to address the gaps.

- ✓ **Recommendations 9-10:** Federal and/or state regulators, as applicable, should consider the gaps identified in this paper and coordinate with utilities to assess whether incorporating additional interconnection requirements and/or studies are appropriate to reliably support integration of large loads. State regulators should work with regulated utilities to review how new loads and planned additional generation impact existing planning and risk assessment frameworks. States may need to adjust their resource adequacy criteria and/or work with their utilities on energy infrastructure expansion.

- ✓ **Recommendation 11:** Policymakers should review interactions between interconnection requirements, existing state regulations and planning processes, and regional grid operator requirements. Additionally, policymakers should work to better understand the full impact of large load integration in their jurisdiction, and review requirements for large load customers to provide operational data and information to TOs, TOPs, TPs, and other entities.

Chapter 1: Introduction to Emerging Large Load Gap Analysis

Intended Audience

This paper is intended for the following NERC registered entities, external entities, and broader groups:

- Planning Coordinators (PC)
- Resource Planners (RP)
- Transmission Planners (TP)
- Transmission Owners (TO)
- Transmission Operators (TOP)
- Distribution Providers (DP)
- Balancing Authorities (BA)
- Reliability Coordinators (RC)
- Large Load Developers, Owners, Operators, or Other Related Companies
- Generator Owners (GO)
- Generator Operators (GOP)
- Load-Serving Entities (LSE)
- Reliability and Security Technical Committee (RSTC) Subgroups
- FERC
- State Regulators and Other Regulatory Entities
- Consumer Advocates

This paper analyzes the gaps in existing practices,[10] requirements,[11] and NERC Reliability Standards related to emerging large loads and provides recommendations for addressing the gaps. Entities responsible for operating and planning the BPS should be aware of these gaps and work to address the gaps in their own practices and requirements to reliably plan and operate the BPS. This paper also identifies areas where potential gaps associated with emerging large loads require further assessment by related RSTC groups.

NERC Large Loads Task Force

The NERC LLWG aims to understand the reliability impacts that emerging large loads, such as data centers and other computational loads, large industrial loads, and hydrogen fuel plants, will have on the BPS. The LLTF has two primary phases identified in the NERC LLTF scope as follows:[12, 13]

- Phase 1: Identify unique characteristics and risks of large loads
- Phase 2: Identify gaps and potential risk mitigation

[10] As NERC Reliability Standards are the minimum performance needed for BPS reliability, utilities have practices that extend beyond the NERC standards. These practices are often related to NERC standards but may extend beyond the standards.
[11] These requirements include interconnection requirements as well as IEEE standards
[12] LLTF Scope
[13] At the time of the writing of this white paper, a new scope for the working group has not yet been RSTC approved. In the interim, the LLWG has inherited the scope of the LLTF.

This paper completes the gap identification portion of Phase 2 of the LLTF scope. This paper, in conjunction with the planned reliability guideline, additionally addresses the mitigation identification portion of Phase 2 of the LLTF scope. The remaining portions of Phase 2 of the scope will be completed in future LLWG activities.

Large Load Definitions

As defined in the NERC LLTF *Characteristics and Risks of Emerging Large Loads* white paper,[14] the definition of "large load" for this paper is the following:

"Any commercial or industrial individual load facility or aggregation of load facilities at a single site behind one or more point(s) of interconnection that can pose reliability risks to the BPS due to its demand, operational characteristics, or other factors. Examples include, but are not limited to, data centers, cryptocurrency mining facilities, hydrogen electrolyzers, manufacturing facilities, and arc furnaces."

Regulatory updates could develop more specific definitions at a later date. On page 16 of NERC's comments submitted in response to FERC's Advance Notice of Proposed Rulemaking on potential reforms to enable the interconnection of large loads to the transmission system, NERC has provided an example timeline for addressing the issues related to the reliable integration of large loads onto the BPS. This example timeline includes filing NERC Rules of Procedure registry criteria changes, along with aligned standards glossary revisions, in Q1 2027. This timeline also includes drafting and filing NERC Reliability Standards during 2027.

More specific definitions could also differentiate within the large load category. The potential impact of several 100 MW loads may be less than the impact of a 500 MW load and may require different treatment. The emergence of gigawatt-scale loads may create exponential complications for study, planning and operations.

Additional definitions related to large load facilities for this paper are the following:

- **Data Center:** "…[A] physical room, building or facility that houses [information technology (IT)] infrastructure for building, running and delivering applications and services."[15]
  - Categories of data centers include traditional data centers, artificial intelligence (AI) training data centers, and AI inference data centers.[16]
- **AI Training:** "…[T]he creation and modification of an AI model and its associated model weights."[17]
- **AI Inference:** "…[T]he process of using a pre-trained AI model to generate output(s) based on new input."[18]
- **Cryptocurrency Mining Facility:** A physical facility housing IT infrastructure for performing cryptocurrency mining.
- **Cryptocurrency Mining:** "…[t]he process of verifying and recording transactions on a blockchain using advanced computing power."[19]

Background

According to NERC's 2025 *Long-Term Reliability Assessment* (LTRA), the aggregated summer peak demand forecast for the North American BPS is predicted to increase by over 224 GW over the 2026–2035 time frame; the aggregated winter peak demand forecast is predicted to increase by 245 GW over this same time frame. Overall, data centers

[14] Available here: White Paper Characteristics and Risks of Emerging Large Loads
[15] What Is a Data Center? | IBM
[16] White Paper Characteristics and Risks of Emerging Large Loads
[17] *Ibid.*
[18] *Ibid.*
[19] What is Cryptocurrency Mining & How Does it Work? - Crypto.com International

account for the majority of this demand increase, while cryptocurrency mining facilities are one of the primary demand drivers for this growth in two portions of the North American BPS.[20]

Changing Gaps

While the gaps in practices, requirements, and modeling identified in this paper were accurate when the content of this paper was initially being drafted, many utilities, entities in the large load industry, and others are working to address the gaps (e.g. by implementing ride-through requirements). Therefore, some of the requirements, practices, and modeling at the time of the publishing of this paper may be different than discussed in this paper.

[20] 2025 Long-Term Reliability Assessment

Chapter 2: Interconnection Processes and Requirements

Due to the complexity and risks that emerging large loads introduce to the BPS, large load interconnection requirements and energization processes must be designed to support grid reliability and incorporate any needs and requirements of the applicable TO, BA, RC, and other applicable entities. Without thorough system study, analysis, review, and approval processes, TOs may interconnect large loads with inadequate design and before operational readiness is ensured. The BPS impacts from emerging large loads can extend beyond the immediate system to which they are connected; they present performance implications of which neighboring systems need to be aware. This section discusses gaps and key issues in the interconnection of emerging large loads, including the lack of comprehensive study and performance requirements in the interconnection process, data sharing, and coordination and collaboration between large load entities, utilities and other entities.

On November 21, 2025, NERC submitted comments in response to FERC's Advance Notice of Proposed Rulemaking on potential reforms to enable the interconnection of large loads to the transmission system. NERC's filing emphasized the need for consistent visibility into new large loads, clear coordination requirements among entities, and robust planning processes that support reliability in a rapidly transforming grid environment. The LLWG supports FERC's examination of these issues in Docket No. RM26-4.

Gaps Related to Interconnection Processes

Because: (i) large loads have not been a focus under Reliability Standards for existing registered entities and (ii) neither large loads nor LSEs are registered entity functions under the NERC registry criteria, this white paper finds that the existing Reliability Standards and interconnection requirements do not adequately mitigate large loads' reliability impacts on the BPS.[21]

- For example, Reliability Standard FAC-001[22] requires TOs to establish interconnection requirements for generators as well as loads, and Reliability Standard FAC-002[23] requires TPs and PCs to study impacts and correct identified reliability risks; however, challenges have been observed with how the interconnection requirements used for generators and traditional loads apply to emerging large loads.
- Even though FAC-001 allows TOs to establish interconnection requirements for "end-user Facilities"[24] like large loads, the current interconnection requirements may not adequately identify the impacts on the BPS, and the requirements may lack clarity and specificity for the interconnection of large loads. The BPS impact from emerging large loads can be much greater than those of historical load additions.
  - A recent NERC report[25] on a large load event highlighted issues that are not adequately captured by existing TO interconnection requirements. Interconnection requirements may have gaps related areas such as voltage/frequency disturbance ride-through, sensitive protection settings, ramping, power quality, and oscillation.
- There are currently no NERC standards for model quality to ensure that the load models reflect the real-time behavior of large loads during system disturbances that cause frequency or voltage variations.[26] Large load entities are currently not directly obligated under existing NERC standards to provide data and timely updates or to maintain data accuracy and appropriate load models. Further discussion on model validation and model quality gaps can be found in **Chapter 7**.

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[21] Based on specific facts and circumstances approximately 10 years ago, the LSE function was removed from the NERC Rules of Procedure. However, the role of this previous function may be able to be tailored to address large load risks.
[22] Available here: FAC-001-4
[23] Available here: FAC-002-4
[24] FAC-001-4
[25] Available here: Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions
[26] See Chapter 7 for more information regarding load modeling gaps.

- Existing Reliability Standards (e.g. FAC-001) do not require TOs to include in their interconnection requirements any BA- and RC-specific requirements for large loads to address unique local system needs such as operational ramping and oscillation monitoring and mitigation. This is likely a gap.

While FAC-002 requires TPs and PCs to study the reliability impact of large load interconnection and requires that the facilities are studied for "…[a]dherance to applicable…[f]acility interconnection requirements…", there is currently no consideration to ensure that the **as-built configuration and parameters**[27] of these large loads are assessed for conformance with applicable facility interconnection requirements (as created per FAC-001); the review via FAC-001 may only involve the **as-planned configuration and parameters.**[28] Also, without a specific assessment process for design, pre-energization requirements, performance validation, ongoing operation, and future modification, TPs and PCs are not in a position to verify that large loads meet capability and performance requirements prior to energization. This also results in a gap in the ability to assess real-time performance in comparison to assumptions studied and impacts the results of planning studies. FAC-002 requires TOs to coordinate with PCs and TPs on studying the reliability impact of end-user facilities. As large loads are not a NERC registered function, the standard does not mandate any coordination or assistance from the large loads during the interconnection studies.

It is evident that industry lacks well-defined and comprehensive interconnection standards and guidelines for large loads that adequately address the potential risks and reliability concerns that large loads pose to the performance of the BPS. Some regional efforts, such as those undertaken by the Electric Reliability Council of Texas (ERCOT), the Southwest Power Pool (SPP), and other registered entities,[29] are underway to address the reliability impact posed by these large loads, with proposed changes aimed at better integrating these new loads and enhancing the overall reliability of the grid. As noted above, NERC supports federal and state attention to interconnection matters.

Commissioning gaps related to real-time operations and outage coordination are discussed in the **Real-Time Operations and Outage Coordination** sub-section of **Chapter 4**.

Lack of Standardization in Comprehensive Load Interconnection Studies and Performance Requirements

> **Key Point**
> There is a lack of standardization in the interconnection studies and performance requirements for large loads. This can lead to inaccurate forecasting, modeling data, and performance requirements, making accurate analysis challenging.

There is a broad alignment with generation interconnection studies and performance requirements in the industry with many entities following the FERC interconnection procedures and agreements[30] for generators. All TOs are required to have facility interconnection requirements per FAC-001 for both generators and loads. However, for large load interconnections, the process is often affected by local utility tariffs (which are under State jurisdiction), so study approaches and performance expectations vary.

These variations highlight the need for more comprehensive and coordinated study components that ensure accurate modeling data and clearly defined performance requirements. Without such requirements, interconnection studies may yield inaccurate analyses, complicating the assessments of system impacts and the identification of necessary network upgrades. This can affect grid reliability and ability of the system to accommodate the increasing number of large load interconnection requests. Furthermore, the limited input from the BA and RC in the development of the interconnection requirements can create operational risk as TOs and utilities may not clearly understand the specific characteristics and operational requirements of large loads.

[27] The configuration and parameters of a facility following commissioning and tuning, representing its final operational state.
[28] The planned parameters and layout of a facility, based on preliminary engineering design prior to construction or installation.
[29] W-A032522-01 Interim Large Load Interconnection Process
[30] Generator Interconnection

Lack of Data Sharing

The effective interconnection of large loads requires a thorough understanding of the loads' specific operational characteristics, including precise energy consumption profiles, power quality impacts, ramp rates, reactive power needs, and resilience or redundancy measures.[31] However, substantial gaps exist in data transparency and standardization, limiting the ability of grid operators and planners to accurately assess and accommodate these new demands.

One key contributing reason for this gap is that, because most large load customers are not registered entities under NERC standards, there are no direct requirements for the load entities in NERC standards.[32] Furthermore, the entity serving this load may also no longer be a function in the registry criteria. LSEs were a registered function under the NERC registry criteria in the Rules of Procedure (ROP).[33] Based on specific facts and circumstances dating from approximately 10 years ago, the function was removed from the ROP.[34] This white paper examines whether the BPS impacts associated with large loads might warrant reconsidering reactivation of the LSE function to support the efficient integration of large loads into the grid. As most being non-registered entities, data centers and similar large loads are not obligated to comply with stringent data reporting and sharing Reliability Standards typically mandated for generation resources. The lack of clear data reporting and sharing requirements can limit operators' ability to request comprehensive operational and performance data, resulting in an incomplete understanding of these facilities' behaviors and impacts on the grid.

The performance of data centers and other power electronic loads is based in part on their hardware and software configurations, and these configurations can be modified (including after initial energization of the load) resulting in changes to the performance characteristics. As part of the process in FAC-002, PCs should have a definition of qualified change[35] that captures impactful changes to these performance characteristics, as these changes can complicate long-term characterization and modeling of load behavior. However, PCs may not have adequate knowledge of data centers to understand what should be considered a qualified change for data centers or other power electronic loads. This could lead to situations in which a large load performs a configuration change that significantly impacts the performance of the facility but does not meet the PC's definition of qualified change, resulting in these impactful changes not being assessed for BPS impacts via the FAC-002 process.

Data center operators are inherently protective of their operational data due to commercial sensitivity, cyber security concerns, and competitive pressures. Sharing detailed consumption patterns or operational profiles could inadvertently reveal proprietary information regarding internal workloads, operational efficiencies, and business practices. As such, data centers are typically reluctant to provide detailed data, preferring to safeguard their competitive advantage, intellectual property, and sensitive infrastructure details. Operators of cryptocurrency mining facilities in particular may avoid sharing detailed operational data due to market competitiveness and strategic responses to electricity price fluctuations. In addition, utilities do not have observability into different categories of loads that are inside the data centers. This leads to operational challenges amid unexpected load dynamics.

The large load developer can be different than the entity that owns or operates the computational equipment. The developer might not have information on the end-user of the facility until late in the interconnection process. This can lead to gaps in the utility's ability to accurately study the proposed facility earlier in the interconnection process.

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[31] See Chapter 7 for more information on the load modeling gaps.
[32] See NERC Rules of Procedure Appendix 5A and NERC Rules of Procedure Appendix 5B for more information on which entities are required to be registered. Available here: Rules of Procedure
[33] Available here: Rules of Procedure
[34] For more information about the history of the NERC Registry Criteria and the removal of certain load-serving entities, see Risk-Based Registration: Phase 1- Enhanced Draft Design Framework and Implementation Plan
[35] See Reliability Standard FAC-002 for more information on the PC defining "qualified change" and the resulting assessments.

This combination of factors creates persistent barriers to robust data sharing and detailed understanding of large loads as well as the modeling of large loads.

Lack of Collaboration and Coordination

The lack of structured communication creates a gap that can result in inefficiencies, misalignment, and increased risk to system reliability. Lack of coordination exists between load owners and the following entities during the interconnection planning, site building, energization, and operation phases of project development:

- Grid operators, owners, and planners
- Regulatory bodies
- State and local governing agencies

Therefore, the coordinated integration of large loads necessitates identification of the stakeholders for every phase of executing the project. Improvement of the collaboration and coordination between these entities will help ensure that large loads can be integrated in a reliable and timely manner.

Moreover, the rapid development timelines of data centers, which can progress from conception to readiness for operation in one to two years,[36] stand in stark contrast to the lengthy timelines required for new transmission and generation infrastructure, which can take four or more years.[37] This mismatch poses significant challenges for ensuring that the grid can accommodate growing demand. To navigate these complexities and support large load integration, deeper collaboration between data center developers and electric utilities is urgently needed.

The LLWG identified a gap in coordination of transmission protection and large load protection. TOs set relay pickups, breaker clearing times, and reclosing schemes on their side of the meter. However, the TOs historically did not need to share those curves with the large load facility owner and operator who program uninterruptible power supply (UPS) and variable frequency drive disturbance ride-through logic. Therefore, the two protection schemes operate independently of one another. Without that visibility and communication, a normally cleared transmission fault can trigger protective systems on the load side even when it is cleared appropriately by the utility. The gap in addressing this risk lies in the current lack of communication and coordination of protective settings from the TO to the large load facility and vice versa. **Chapter 6** further discusses the disturbance ride-through concerns related to large loads.

Certain design considerations (e.g., the facility's transfer to backup power supply and the return to utility during/after voltage disturbances) for large loads can significantly impact the characteristics and risks of that large load as seen by the grid. There may currently be gaps in the coordination between the grid operators/planners and the large load entities regarding these design decisions. This coordination would help ensure that the BPS reliability impacts are considered in the design of the facility. This consideration could also extend to decisions regarding how data center compute is implemented from a software perspective.

[36] The utility may require more time for interconnection.

[37] However, the data centers may not reach their full operational capacity upon initial energization but may ramp up to their full capacity at a later date.

Chapter 3: Planning and Resource Adequacy

Many emerging large loads are seeking to connect to the system in time frames prior to the system planning horizon. This poses planning and resource adequacy challenges, as the amount of load attributed to large loads was not included in long-term planning forecasts, meaning that current transmission planning and generation procurements generally do not account for these new large loads. This can result in the BPS struggling to accommodate the new large loads without resource shortfalls or transmission constraints.

A number of gaps are preventing large loads from being accurately included in new studies. These include a lack of data around emerging large loads (including their demand patterns, project information, and demand responsiveness) and a lack of data standardization and sharing. When information is received by grid planners, it is often only shared when loads are seeking interconnection, which is commonly in the near term and prevents the loads from being included in long-term planning before they are energized. There are also gaps in current resource adequacy studies, practices, and generation procurements as well as transmission planning Reliability Standards.

This chapter identifies the gaps related to planning and resource adequacy. Portions of this chapter related to demand forecasting reflect the research performed by the Energy Systems Integration Group (ESIG) Large Loads Task Force.[38]

Demand Forecasting Gaps

The increase in large loads is impacting system demand in a number of ways. Large loads impact intraday demand shapes as well as seasonal and annual demand patterns. There is also significant uncertainty associated with these loads that makes them difficult to forecast. Traditional load forecasting methods may not be sufficient to capture these changes accurately, for reasons which will be expanded upon below.

Planners lack certainty about key mid- and long-term forecasting parameters for prospective large loads, including the following:[39]

- Schedule for initial energization
- Ramp rate[40]
- Ultimate load after ramping from initial energization
- Load shape (or load factor)

> **Key Point**
> Planners lack a historical basis to assess the collective certainty of some types of large loads.

One reason for this is that planners lack visibility into the certainty of individual large loads' business plans, as some are evaluating interconnection in different areas and most face risks related to construction schedule, technical plans that relate to energization ramps, economic viability, financial challenges, and the comparative cost and schedule for interconnection. Furthermore, planners lack a historical basis to assess the collective certainty of some types of large loads on these forecasting parameters, particularly for novel industrial or data center loads. Accordingly, planners typically apply professional judgment to the available data when evaluating these uncertain forecasting parameters.

Demand forecasts are developed by utilities, system planners, and PCs. The PCs may source some or all of their demand forecasts from member utilities and may also develop portions of the demand forecast themselves. In the

[38] Large Loads Task Force - ESIG

[39] This list is essentially identical to four of the metrics provided in Figure ES-1 of the ESIG Large Loads Task Force report titled "Forecasting for Large Loads: Current Practices and Recommendations". Available here: Forecasting for Large Loads: Current Practices and Recommendations

[40] Many large loads do not initially energize at their full demand but ramp to this demand over multiple years.

case of information on large loads, PCs, TPs, and RPs are mostly or wholly dependent on information provided by the utilities, which may lead to forecasts relying on what has become out-of-date information.

Key Point
Current resource adequacy practices may not fully account for the complexities introduced by large loads.

Some system planners provide guidance to their members on the information that they require and collaborate with their members on practices. Some utilities and system planners have established standardized practices (e.g., via gates, stages, policy support, financial commitment) for evaluating the key forecasting parameters as large loads request interconnection and engage in obtaining utility service or otherwise securing power. The divergence of large load demand forecasts is a result of the lack of well-established practices, and at least until technology evolution stabilizes, the certainty of those forecasts cannot be guaranteed.

At this time, due to customer confidentiality and the lack of institutional data sharing practices, utilities and regional TPs do not typically share detailed information with one another on the operating characteristics, ramp rates, and load profiles necessary for improved forecasting of the various types of large loads. Development of such practices could compensate for the lack of historical basis for assessing collective certainty of forecasting parameters faced by planners in many areas.

Uncertainty exists around how large loads may participate in peak-shaving, demand-response, or price-responsiveness programs. Program participation has typically been evaluated on a post hoc basis and then factored into resource adequacy and demand forecasts. Existing NERC and regional standards as well as engineering practices do not explicitly address how system operators or planners should incorporate potential large load participation scenarios into resource adequacy and demand forecasts. Without knowing how the loads will participate, utilities are forced to make assumptions that can result in under-procuring both transmission and generation. In a similar vein, there is a gap in requirements for large loads to share information on behind-the-meter generation information at prospective load sites and for utilities on how to include that information when performing studies. Currently, many load forecasters do not obtain adequate information on behind-the-meter generation. This may be because it is not commonly planned. In any case, it is unclear if and how utilities should consider information about behind-the-meter generation in load forecasts and resource adequacy studies. This information is necessary for planners as they consider the impacts of peak-shaving, demand-response, or price-responsiveness programs in their studies.

Resource Planning Gaps

Since NERC Reliability Standards are not directly applicable to most large loads and to LSEs, the information provided to planners from the large load customers or TOs may be inaccurate, challenging long-term planners' efforts to ensure that the system is designed to serve additional load growth and maintain additional generating capacity. Although Reliability Standard BAL-502-RF[41] is applicable strictly to the ReliabilityFirst region, it is indicative of the process that can be used for the determination of an entity's planning reserve margin (PRM). However, large loads are not included explicitly in this standard or mentioned in the context of resource adequacy analysis, representing gaps in this standard. Reliability Standard MOD-031[42] requires registered entities to provide accurate demand forecasts and energy data for resource adequacy planning. However, since neither LSEs nor most large loads are NERC-registered, MOD-031 does not explicitly require information from the owner of the end-user equipment. This can affect the sharing of critical load forecasting data or detailed consumption profiles that represent the consumption of end-user equipment. This omission reduces the accuracy and reliability of resource adequacy studies.

Current resource adequacy studies do not fully account for the impact of new large loads on demand growth and geographic load patterns. The current approach primarily focuses on conventional supply-side metrics and

[41] Available here: BAL-502-RF-03
[42] Available here: MOD-031-3

retirements, which may not be sufficient to address the unconventional yet significant demand posed by these large loads. Furthermore, data centers are bidding into multiple areas for interconnection, which results in overstatement of expected demand for these large loads. Additionally, existing load forecasting methods, procurement strategies, and development of generation and transmission infrastructure may be insufficient to manage the rapid and concentrated growth in demand from large loads.

While resource adequacy planning traditionally focuses on ensuring sufficient generating capacity and reserves to meet expected demand using metrics like loss of load expectation (LOLE) and PRM, existing practices may not fully account for the complexities introduced by large loads. Specifically, the addition of large loads, combined with a number of other factors—such as the increase of variable inverter-based resources (IBR) and distributed energy resources (DER), the frequency of thermal outages during periods of extreme weather (which are becoming more common and less predictable), and aging infrastructure—can all further complicate risk assessment. Additionally, the data used in resource adequacy models to determine PRM does not reflect the effects of large loads in intra-hour behavior and reserve requirements, hourly load shapes, peak and energy forecasts, load forecast uncertainties, and the potential for delays or constraints associated with the development of necessary transmission and generation infrastructure are not considered in resource planning models.

There are no requirements in NERC standards explicitly requiring resource adequacy checks before integrating a new large load onto the system or before the peak demand of an existing large load is increased. This may be a gap in FAC-002. Additional discussion on FAC-002 and related processes can be found in **Chapter 2**.

Transmission Planning Gaps

Large loads are evaluated and planned for by DPs, TOs, TPs, and PCs in various ways depending on their engineering practices, requirements, and the Reliability Standards[43] with which they are required to comply. Transmission planning is based on multiple NERC standards that establish the actions that entities must take to evaluate the BPS and ensure its reliability. Most notably, Reliability Standards TPL-001[44]and MOD-032[45] have been the basis for the development of planning requirements and modeling data submissions for PCs and TPs to perform their work.

TPL-001 establishes planning performance requirements and requires TPs and PCs to conduct annual planning assessments. The event categories in the standard do not explicitly include the loss of large loads unless they are extreme events or unless the load isolated because of the loss of other transmission elements. Another gap in the existing process is in the comprehensive analyses, especially regarding steady-state or dynamic risks due to clustered loss of large loads in an area (e.g., failure to ride through disturbances, sensitive protection settings). As a result, the current evaluations may not be sufficient to plan a system that can accommodate the growing number of large load interconnection requests. Similarly, MOD-032, which establishes the modeling data requirements for the development of transmission planning models, does not adequately cover all modeling requirements for large loads, such as peak demand, load power factor, and dynamic behavior.

The scenario selection for conducting the reliability assessments with large loads is critical in understanding the reliability risks. TPL-001 requires dynamic load models only for near-term studies that look into peak load conditions. However the impacts to the system from the large load could be unique and material during off-peak conditions, when a certain large load[46] might be the biggest load on the system with a very different generation dispatch than was studied in the peak load assessment. These considerations will be important for reliability assessments with large loads. Additionally, TPL-001 does not require load models to be used in long-term stability studies or specify that peak and off-peak conditions should be studied in the long-term stability studies. These may be gaps in this standard.

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[43] Historically, the LSE was one of the entities that had standard obligation to provide demand data for these Reliability Standards.

[44] Available here: TPL-001-5

[45] Available here: MOD-032-1

[46] Given that a data center has a very different load consumption pattern as compared to older large industrial facilities like a paper or steel mill.

> **Key Point**
> Traditional planning practices are often focused on the mid- to long-term time frames, while some large loads can connect very quickly in the near-term time frame.

FAC-002 studies help ensure that end-use facilities are reliably integrated to the system. TPL-001 studies focus on the near- to long-term planning horizons spanning 1–10+ years and look at the system from a more holistic perspective. While FAC-002 studies help address many of the impacts from large loads, the TPL-001 studies are still important as they help identify upgrades needed when looking at the overall system. In North America, transmission project development starting from the planning phase to the construction phase can take 5–10 years or even longer to complete. However, it has been observed that some large loads are seeking to interconnect to the system in very short time frames, some within a year. Additionally, some TPs may normally develop models that represent scenarios that are at least two years in future, meaning that such models would not be adequate to assess the impact of large loads interconnecting in shorter time frames. This issue becomes more pronounced for dynamic models as several entities develop dynamic models that represent scenarios at least five years into the future. Therefore, while localized impacts to the BPS from large loads might be addressed in the FAC-002 processes, overall system issues, such as ensuring bulk transfer capability for energy deliverability to clusters of large loads, may not be addressed via TPL-001 processes before the large loads are energized.

Accurately predicting the demand from large loads for long-term planning studies is complex. Misestimations of the magnitude or location of future loads can lead to underbuilding transmission infrastructure or building transmission infrastructure in the wrong locations, which can significantly impact reliability. While many of the issues caused by misestimation of demand can be addressed by FAC-002 interconnection studies for end-use facilities, misestimation of demand can still lead to system-level issues such as lack of bulk transfer capability on the system. It is challenging for TPs or TOs to determine in advance which large load interconnection requests will materialize; however, there is no guidance or Reliability Standards that provide a framework to determine which potential loads to include in long-term planning studies. With the rapid increase in large loads seeking interconnection, load may also outstrip generation in transmission planning cases. TPL-001 does not provide a framework for how to address the situation when load exceeds generation in long-term planning models; there is also a lack of guidance in the industry regarding how to address this situation.

Lack of Standardization/Coordination Between Entities

With current planning practices in some, but not all, markets and areas operating in silos, there can be a lack of standardization and coordination across load forecasting, generation, and transmission planning on how to deal with new large load requests and interest. For example, a regional transmission organization (RTO) may perform transmission planning studies with limited load forecast and generation information provided by LSEs; additionally, there is no standard or guidance for RTOs on how to interpret this load forecast and generation information when conducting studies.

Chapter 4: Balancing and Operations

In the operations horizon, system operators are responsible for ensuring that the BPS is reliable and secure. This includes ensuring that load and generation are balanced, which is required to maintain stability. Many emerging large loads, particularly computational facilities, are power electronics-driven load and are highly responsive (changing consumption patterns based on external triggers) and exhibit pulsating or nonlinear demand profiles and voltage sensitivity to grid conditions. In fact, it is arguable that these large loads can operate as controllable Bulk Electric System (BES)[47] elements that can significantly ramp up and down with high oscillatory behavior, impacting grid reliability. Their size, controllability, and variability introduce potential reliability risks to the BPS comparable to those of a generator but with the added complexity of being on the demand side.

Balancing Gaps

If a BA lacks awareness of large load ramping, the rapid ramping up and/or down of one or more large loads may cause a variety of reliability impacts, including frequency excursions, voltage and thermal violations, and instability risks. The gap in addressing ramping risks affects both real-time operations and the operation planning horizon. This complicates unit commitment decisions and next-day reliability studies. Since there are no specific requirements in place in the NERC standards for large loads to provide necessary information such as large load models and ramp rates to RCs, BAs, and TOPs, the ability to conduct analysis and assessments on the impacts of large load ramping on system reliability is hindered. Without adequate data, real-time operators may not be aware of the risk posed by large loads, and issues may go undetected until they are observed in real time. This could place the burden on real-time system operators to mitigate reliability risks related to voltage violations and frequency deviations in real time.

Key Point

NERC standards do not provide specific requirements for large loads or LSEs to provide data; this leads to real-time operators being unaware of risks posed to the BPS.

BAs might not have visibility of the demand of individual large loads and may not have sufficient information to know when the large load is expected to increase demand to pre-disturbance levels after a large load demand reduction occurs for a system disturbance. This lack of visibility and information could lead to the BA unnecessarily bringing generation off-line to balance the frequency after a large load demand reduction. If the large load increases its demand to pre-disturbance levels after the BA brings generation off-line, further difficulty in controlling frequency could be experienced. This lack of visibility of individual large load demand (both real-time and forecasted) may be a gap. Additionally, the lack of information may be a gap in coordination between the TOP and BA.

Current gaps in NERC standards also include the absence of explicit requirements to represent or consider the operational behavior of large loads in reliability assessments and situational awareness. While Reliability Standards IRO-010[48] and TOP-003[49] require BAs, TOPs, and RCs to obtain data necessary to perform reliability assessments, these standards do not obligate large loads to provide ramping characteristics, dynamic performance data, or usage profiles. Insufficient data and representation could compromise analysis accuracy, including among new NERC standards like Reliability Standard BAL-007-1 – Near-term Energy Reliability Assessments.[50]

Short-Term Demand Forecasting

Accurate forecasting of large loads in the transmission grid is critical for ensuring BPS reliability. However, several challenges complicate this task, requiring advanced methods and continuous improvements in forecasting techniques. There is a clear gap in how the utilities develop forecasts when considering large loads.

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[47] Glossary of Terms Used in NERC Reliability Standards
[48] Available here: IRO-010-5
[49] Available here: TOP-003-6.1
[50] Available here: BAL-007-1

Load data, especially for large commercial and industrial customers, is often incomplete, aggregated, or lacks necessary granularity, such as hourly or daily usage trends for use in short-term load forecasting. System operators' forecasting methods may not account for rapid changes in load forecasts for industrial and commercial loads caused by business decisions related to the load. Reliability Standards TOP-001[51] and TOP-002[52] cover operations and operations planning. When considering large loads, these standards may not adequately cover the gaps associated with load ramping and forecasts. Additional discussion regarding gaps related to demand forecasting is provided in **Chapter 3**.

Impact of Large load Ramping and Disturbance Ride-Through Limitations on Area Control Error

Large loads can significantly impact a BA's load profile, posing operational challenges in controlling area control error (ACE), the real-time indicator of generation-load balance and interconnection frequency stability. An example of sample ACE variations due to large loads when compared to BA ACE Limits (BAAL) is provided in **Figure 4.1**.

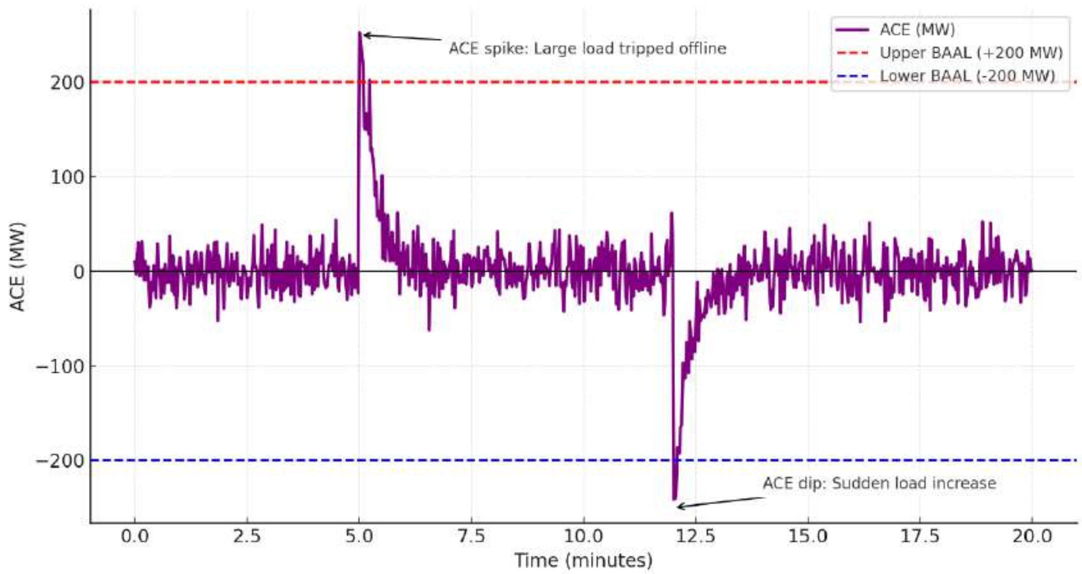

Figure 4.1: Sample ACE Variations Due to Large Loads

- **Existing Reliability Standards contain gaps in addressing the impacts of large loads on ACE:** Although the BAL-001 Reliability Standard[53], which includes Control Performance Standard 1 and Balancing Authority ACE Limit, provides a framework for managing ACE, it does not explicitly account for scenarios where large loads exhibit rapid and unpredictable ramping behavior. This standard requires that "[e]ach [BA] shall operate such that its clock-minute average of Reporting ACE does not exceed its clock-minute Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes." Frequency excursions due to large load ramping behavior or other behavior that are corrected within 30 minutes are not a violation of this standard. However, frequency stability may still be at risk in these scenarios. Adherence to the Control Performance Standard 1 requirement in BAL-001 is based on overall performance during the previous 12 months. Sub-optimal performance during one portion of the year can be compensated for with good performance during another portion of the year. As with the BAAL requirement, frequency stability may be at risk in specific timeframes, although Control Performance Standard 1 requirements may be met during the overall 12 months. Additionally, current Reliability Standards lack specific guidance or constraints on how quickly large loads may ramp.

[51] Available here: TOP-001-6
[52] Available here: TOP-002-5
[53] Available here: BAL-001-2

- **Existing NERC Standards do not fully address the need for faster and more flexible balancing actions necessitated by the inherent variability and unpredictability of large loads:** While Reliability Standards BAL-001, BAL-002[54], and BAL-003[55] collectively set standards for overall ACE control and frequency stability, they do not explicitly differentiate the operational treatment between large generator outages and large load perturbations. This lack of specificity could result in inadequate preparedness and insufficient operational tools to manage ACE effectively amid the growing prevalence and unique characteristics of large, dynamic loads.

- **There is a gap in the analysis of the largest reasonable load loss:** All BAs submit their largest credible generator N-1 losses as well as their largest generation loss from a remedial action scheme event as part of the Reliability Standard BAL-003 process. This largest credible loss of generation feeds directly into the calculation that determines the amount of frequency response required from the interconnection and from each BA. If the largest credible load loss is not analyzed on a recurring basis, there could be a gap in preparing for the load loss/reduction events.

- **BAL-002 does not explicitly include large load tripping or ramping events within the balancing contingency event definition:** This standard, focused on the disturbance control standard, primarily addresses the sudden loss of large generation resources or restoration of demand utilized as a resource but does not explicitly include large load tripping or ramping events within the balancing contingency event definition. This represents another critical gap, as the sudden addition or loss of large loads can have equivalent reliability impacts as generation contingencies. Gaps related to large load disturbance ride-through are also discussed in **Chapter 5**.

Additional discussion on gaps related to frequency stability is provided in **Chapter 5**.

Operations Gaps

The following discussions identify gaps related to large load ramping, real-time operations, and outage coordination.

Impact of Large load Ramping on System Reliability and Operations Planning

Today, when operating or planning for operations, system reliability is assessed by evaluating recognized contingency events and monitoring expected outcomes. With respect to large loads, these events could include the loss of a single point of connection for a load station. However, as noted above, multiple large loads in a region could collectively reduce or increase their consumption by unknown amounts, which are not events currently considered in operations or operations planning. These events could lead to reliability issues including thermal violations/exceedances, unacceptable voltage levels and voltage instability, and transient instability of the system.

Currently, planning (TPL-001, FAC-002, FAC-011[56]), operations planning (TOP-002, IRO-008[57]), and operations (TOP-001, IRO-008) related Reliability Standards do not consider the impacts of large-scale ramping, disconnection, and reconnection events. Given the possible significant impacts to the BPS, potentially leading to uncontrolled separation and cascading outages, there is a gap in appropriately considering the impacts of these types of events.

In addition, disturbance ride-through performance remains an area of concern for data centers and cryptocurrency mining facilities that are sensitive to transient voltage drops. These facilities have demonstrated tendencies to disconnect for faults outside of their zone of protection—or more simply for faults on lines they are not connected to—which is unexpected. This type of behavior is not modeled in operational or operations planning analyses, and excessive facility tripping can also lead to thermal violations/exceedances, unacceptable voltage levels and voltage

[54] Available here: BAL-002-3
[55] Available here: BAL-003-2
[56] Available here: FAC-011-4
[57] Available here: IRO-008-3

instability, and transient instability of the system. As discussed in **Chapter 2**, some of the disturbance ride-through performance issues can be due to a lack of communication and coordination of protective settings from the TO to the large load facility and vice versa. Gaps related to large load ride-through are also discussed in **Chapter 5**.

Real-Time Operations and Outage Coordination

Large loads pose a risk to the BPS if their operations are not coordinated with BPS operators. If a large load operates in a way that is not expected by the existing or neighboring RC/TOP/BA, there could be concerns about operating reserves and system stability. To support safe and reliable integration of large loads, TOPs/BAs, RCs, LSEs, and large loads need to coordinate.

As previously mentioned, RCs/BAs/TOPs need data that accurately represents large load facilities to properly account for these facilities in studies and analysis. During commissioning, the system operator needs to conduct multiple checks to ensure the operational readiness prior to energization. RCs/BAs/TOPs may have gaps in the following engineering practices that should be reviewed:

- Pathways for integrating new loads into their modeling tools and energy management systems (EMS)
- Processes for obtaining as-built modeling data and update studies, if required based on changes, prior to initial energization and to integrate the latest data into modeling tools and EMS
- Operational agreements covering communication for normal and emergency operations
- Processes for verifying communication pathways
- Processes for verifying protection configurations and setup including monitoring (such as power quality and oscillation detection)
- Processes for large loads coordinating planned outages with the TO and/or TOP as well as the BA.

Large loads are not currently obligated to establish interpersonal communication capabilities with system operators as outlined in Reliability Standard COM-001.[58] Unlike generators, which must adhere to requirements regarding communication and operating instructions within Reliability Standards PER-005, COM-002,[59] and TOP-001, large loads are not subject to these requirements. These gaps can lead to inefficiencies and miscommunications during critical situations, potentially exacerbating emergencies and hindering effective mitigation efforts.

A key component of maintaining BPS reliability is the ability to coordinate transmission and generation outages to ensure that an outage does not cause a contingency violation or generation shortage prior to the outage. BAs and TOPs currently review transmission and generation outages but not load outages. Reliability Standard IRO-017[60] addresses the outage coordination process for RCs/TOs/BAs but does not consider outages of large loads. The procedures of RCs/TOs/BAs also do not currently cover large load outages.

Operations Tools

Advanced tools like stability analysis or oscillatory signal analysis tools may not be available to operators in real time. These tools are likely needed in areas with high penetrations of IBRs; similarly, they are also likely needed in areas with high penetrations of large loads such as data centers.

[58] Available here: COM-001-3
[59] Available here: COM-002-4
[60] Available here: IRO-017-1

Chapter 5: Disturbance Ride-Through, Stability, and Power Quality

Since large loads can significantly impact BPS reliability, it is crucial to evaluate their performance characteristics, such as ride-through capabilities during grid disturbances, and their effects on system stability and power quality. There are minimal NERC Reliability Standards and regional requirements that adequately capture and mitigate the reliability impacts of large load interconnections to the grid. There are also limited established industry-wide capability and performance expectations (e.g., IEEE 2800[61] for IBRs) for how large loads should be designed and operated to support the needs of the grid or avoid negatively impacting BPS or local reliability. IEEE and International Electrotechnical Commission (IEC) standards applicable to large loads regarding harmonics and other factors exist, but there are no requirements to help ensure that large loads do not negatively impact BPS reliability. For more information on simulation tools, modeling terminology, and application of the tools and models, see **Appendix A**.

Voltage Disturbance Ride-Through Gaps

Many large loads have internal protection and control systems that are sensitive to grid disturbances. As a result, large loads are prone to disconnect or transfer load to backup systems during normally cleared system faults. Large load ride-through capability and performance need to be studied and understood by system operators. Otherwise, this lack of disturbance ride-through can lead to large amounts of load disconnecting or reducing demand during voltage and frequency perturbations that would not normally result in such behavior. This limited voltage disturbance ride-through capability can pose multiple reliability challenges to the grid, such as balancing and stability impacts. The protection and control standards such as Reliability Standards PRC-019,[62] PRC-024,[63] and PRC-029[64] do not discuss large load performance during voltage and frequency deviations.

NERC Reliability Standards and regional requirements that dictate how system studies and analyses are performed do not conventionally assess transmission contingencies that involve the simultaneous loss of nearby voltage-sensitive load in addition to one or more faulted transmission facilities. Without predictable disturbance ride-through performance from large loads, such as the performance required by generators with the enforceable Reliability Standard PRC-029 or even the voluntary IEEE 2800, conducting studies to appropriately gauge and mitigate this risk is challenging. Additionally, there is a gap in capturing high-resolution data needed for studies and analyses that assess the performance characteristics of large loads. NERC standards like Reliability Standard PRC-028[65] lack data monitoring requirements for large loads to assist TPs and PCs with disturbance ride-through performance evaluations.

There is a lack of coordination and data sharing between RCs, BAs, TOPs, TOs, TPs, and large load entities on how and when large loads should ramp to pre-disturbance demand levels upon voltage recovery after a voltage disturbance. Because of this, the BAs in the system may reduce total generation due to an observed high frequency after a large load demand reduction or trip event, not knowing when the load will return to pre-disturbance demand levels. However, after the generation has been re-dispatched, large loads might suddenly begin ramping back to the grid, causing frequency to drop due to the mismatch of generation levels and load levels. Additionally, this return to pre-disturbance demand levels after a voltage disturbance cannot be studied in simulation due to lack of information being shared regarding when and how quickly the load will return to pre-disturbance levels; this presents a significant gap between system response in simulation studies compared to what may happen during a real event. In

[61] Available here: IEEE 2800-2022
[62] Available here: PRC-019-2
[63] Available here: PRC-024-3
[64] Available here: PRC-029-1
[65] Available here: PRC-028-1

comparison, ride-through performance and recovery of IBRs during system disturbances have been well defined and adopted in performance standards such as PRC-029.

RCs, BAs, and TOPs may use the Information Technology Industry Council (ITIC) curve to make assumptions about when large electronic loads will reduce consumption or transfer to backup UPS or generation. The ITIC curve is commonly used in the design of IT equipment, such as computers and servers. The ITIC curve is applicable to power supplies, but it may not be applicable for grid studies if there is a UPS between the grid and the power supplies. UPS settings or other site-level protections may impact the disturbance ride-through characteristics of the load. Disturbance ride-through characteristics may vary significantly between large load facilities, which may notably impact area-wide studies involving loss of large loads during grid disturbances. This is another potential gap due to the lack of verifiable large load ride-through data as previously mentioned.

IEEE Standard 1668[66] provides recommended practices for voltage sag and short interruption ride-through testing for end-use electrical equipment rated below 1,000 V. The Tennessee Valley Authority uses this standard to assess the voltage sag ride-through performance of large loads, including industrial and data center loads. Compatibility with IEEE 1668 allows loads to ride through the most common transmission-caused voltage sags but allows load to trip off-line for deeper or longer voltage sags. Although this standard does provide recommended disturbance ride-through capability of end-use equipment, it does not establish minimum ride-through performance requirements for large loads connecting to the BPS.

The absence of a clearly defined voltage disturbance ride-through capability leads to highly variable responses among large loads. Furthermore, RCs, BAs, and TOPs often lack visibility into these behaviors. Large load interconnection requests do not currently require submission of dynamic models with specified disturbance ride-through capabilities, nor are such capabilities typically verified through testing after commissioning.

Key Point

The absence of a clearly defined voltage ride-through capability leads to highly variable responses among large loads.

However, entities including ERCOT, SPP, and Dominion Energy are developing disturbance ride-through requirements for large loads. This work will help to address the gaps discussed above.

Frequency Disturbance Ride-Through Gaps

Frequency disturbance ride-through refers to the ability of a resource to remain connected to the grid during system frequency deviations within defined thresholds and durations. This capability supports grid stability by preventing unnecessary tripping of generation resources during events so the system can recover.

Frequency disturbance ride-through standards are currently focused on generators, with no equivalent requirements established for large loads. While loads are generally expected to remain connected through “reasonable” frequency disturbances, there is no formal definition of what constitutes reasonable, nor any enforceable criteria for performance. Historically, loads dropping off during low-frequency events has been a net positive for grid reliability. However, if large loads trip or transfer to backup generation for high-frequency events, the problem could be exacerbated. This identifies a potential gap since large loads fall outside the scope of existing NERC Reliability Standards that govern frequency disturbance ride-through.

PRC-024 and PRC-029 define the allowable frequency and voltage protection settings for generating resources, ensuring that generators do not trip off-line during system disturbances that fall within a defined “no-trip zone.” The intent is to ensure that generator protection settings do not exacerbate grid instability. Although PRC-024 and PRC-029 were written for generating resources, some elements of the standards may have relevance when considering

[66] Available here: IEEE 1668-2017

performance expectations for large loads, particularly the sections that define frequency thresholds and minimum ride-through times.

Similarly, IEEE 2800 sets performance requirements for IBRs, including frequency disturbance ride-through capabilities. IEEE 2800 applies to generation resources only and does not address load facilities. PRC-024 and PRC-029 are also only applicable to generation resources. However, it is worth noting that both these NERC standards and the IEEE standard provide a structured framework for how resources interact with frequency disturbances on the grid, which could potentially inform future approaches to load behavior.

Harmonics and Interharmonics Gaps

Electronic devices such as adjustable speed drives, rectifiers, and switched-mode power supplies—commonly found in emerging large loads—produce harmonics and interharmonics[67] that can contribute to unacceptable levels of voltage and current distortion in the BPS. While the large quantity of electronic devices present in emerging large loads is remarkable, existing standards provide guidance on acceptable limits that can be effectively applied to large loads.

IEEE Standard 519 establishes voltage and current distortion limits that, if followed, minimize the chances of adverse impacts related to distortion. As the limits set by IEEE 519[68] are intended to ensure compatibility between the load and public power supply system, they are applied exclusively to the point of common coupling (PCC) and do not apply to individual devices or buses within the facility. In IEEE 519, management of distortion is seen as a joint responsibility between the system owners or operators and the user (e.g., the owner/operator of the large load). Broadly speaking, the user is responsible for limiting the current distortion that their loads produce, whereas the grid operator is responsible for limiting the voltage distortion that is produced when distorted currents flow through system impedances. The guidelines defined in IEEE 519 can be effectively applied to large loads. The standard specifies allowable distortion limits for nominal voltages ranging from 120 V to above 161 kV. The standard accounts for the fact that larger loads can have greater effects on voltage and current distortion. Allowable limits are adjusted based on the short-circuit ratio of the user's facility and nominal voltage of service. Users connected to higher voltages and lower short-circuit ratios have the potential to produce greater distortion and are therefore subjected to stricter limits.

Some large load sites have significant quantities of generation (more than or equal to 10% of the annual average load demand). If this generation contains IBRs and/or DER, IEEE 519 may not be applicable—either IEEE 2800 or IEEE 1547[69] should instead be referred to for harmonic and interharmonic limits. IEEE 2800 addresses transmission-connected IBRs and IEEE 1547 addresses DERs.

IEEE standards provide requirements that can be applied to limit harmonics; the limits, applicable to both voltage and current, are common to all large load interconnections without any further coordination among them. However, lack of coordination among different large load interconnections may create situations where individual loads are compliant with limits at their connection point but create non-compliance at other portions of the system (in comparison, other jurisdictions, such as most European transmission system operators, provide individual harmonic emission limits to each customer and these are enforced as part of the compliance process).

Some industry practices may have gaps when it comes to determining interharmonic limits. IEEE 519 does not provide universally applicable limits for interharmonics. This is because the sensitivity of differing loads to interharmonics varies significantly, and a set of limits intended to accommodate all possibilities appeared to be very restrictive to the

[67] The term "interharmonic" is used as defined in IEEE 519-2022 and encompasses subharmonics and supraharmonics as well.
[68] Available here: IEEE 519-2022
[69] Available here: IEEE 1547-2018

committee that developed IEEE 519. Thus, if a large load is anticipated to produce interharmonics, analyses beyond those defined in IEEE 519 are likely necessary.

Some system owners/operators may encounter instances where there are no existing technical solutions by which a large load can meet typical interharmonic limits. While the technical solutions themselves are not the focus of this white paper, the possibility that it may not be technically feasible to employ standard limits does indicate an important gap in industry practices. Prior work by the IEEE Interharmonic Task Force suggests that interharmonic voltages in the subharmonic range[70] should be limited to less than 0.1% of nominal.[71] Some AI workloads may produce subharmonics that are tens or hundreds of megawatts in magnitude. Reducing subharmonic magnitudes below suggested limits is sometimes beyond the capability of traditional solutions such as static VAR compensators. Load smoothing with utility-scale battery storage and grid-forming inverters can reduce the subharmonic current magnitude by roughly 70%.[72] Other methods for load smoothing include static synchronous compensators[73] with supercapacitors.

Some industry practices may have gaps when it comes to managing transmission system voltage distortion. Even if the anticipated current distortion produced by the large load is within the current limits recommended in IEEE 519, high system impedance or an electrical resonance (e.g., involving a nearby transmission system capacitor) may still result in unacceptably high voltage distortion. System owners/operators who have previously had very little current distortion present in their transmission system may not have practices in place to proactively identify and mitigate unacceptable levels of transmission voltage distortion.

Stability Gaps

Maintaining a stable power system requires addressing a broad range of issues. For consistency and clarity, gaps related to stability problems are discussed in terms of the taxonomy shown in **Figure 5.1**.[74] Forced oscillations are also discussed in this section. Even if the power system is technically stable, forced oscillations can interact with the dynamics associated with different stability problems in a way that can cause power outages or equipment damage.

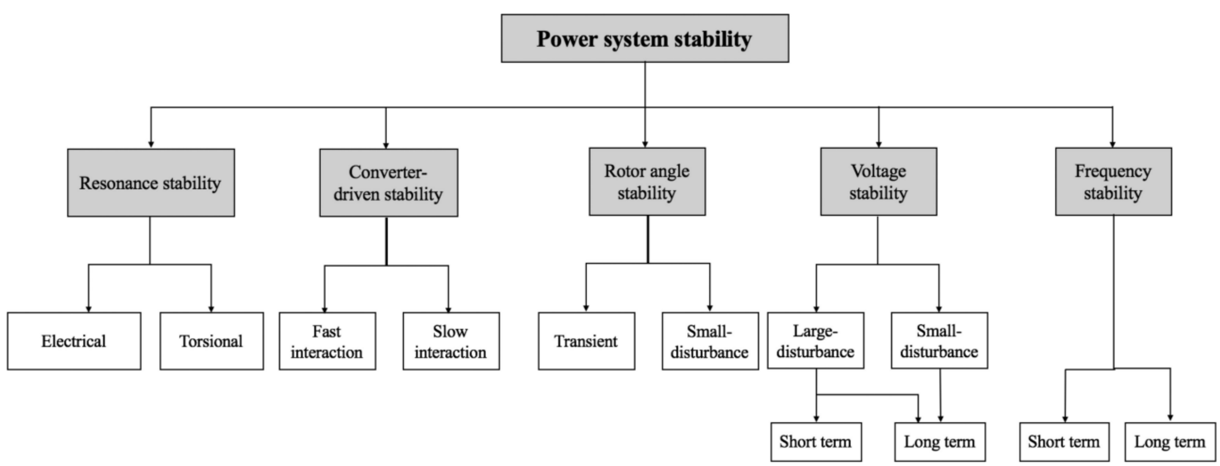

Figure 5.1: Taxonomy of Power System Stability

[70] Interharmonics with frequencies that are "below the system fundamental frequency" (IEEE 519-2022)
[71] See Issues and Challenges Related to Interharmonic Distortion Limits
[72] See page 77 of LLTF April Meeting & Technical Workshop Presentations
[73] Also known as STATCOMs
[74] See Definition and Classification of Power System Stability -- Revisited and Extended

- Gaps relating to rotor angle stability, voltage stability, and frequency stability primarily relate to concerns that the existing practices used to conduct transient stability studies are not accurate or comprehensive enough. These concerns stem from ways in which emerging large load dynamics differ from most traditional load.
- Gaps relating to resonance stability and converter-driven stability are more fundamental in nature; the specific mechanisms by which large loads might contribute adversely to converter-driven or resonance stability are ill-defined, representing a major obstacle to defining study and modeling requirements clearly enough for practices to be developed around them.

Because accurate modeling is an essential part of maintaining power system stability, many of the gaps relating to stability are modeling related. General gaps in large load modeling practices are discussed in Chapter 7, and the scope of modeling discussions in the following subsections is limited to specific modeling gaps that are important for the stability studies under discussion. All models are flawed, and different stability problems require different modeling approaches. Each kind of stability study will require practice improvements tailored to the study's specific purpose.

Rotor-Angle Stability

Large loads can produce rapid and significant fluctuations in real power that can result in generators swinging beyond their rotor-angle stability limits and losing synchronism. There are gaps in the models used and scenarios considered in the transient stability studies used to identify specific contingencies where rotor-angle stability might occur.

- **Model-related gaps stem primarily from the lack of well-defined disturbance ride-through behavior, as discussed earlier in the chapter:** Existing load models used to represent large loads in transient stability studies do not accurately predict whether the large loads will trip off-line or remain connected during a given disturbance.[75] They also may not accurately predict large loads' real and reactive power consumption during the fault or postfault recovery and/or reconnection dynamics. All these modeling aspects can significantly affect the outcome of rotor-angle stability studies. Note that, from a stability and modeling perspective, the essential gap is not necessarily the lack of formal requirements, it is the mismatch between the models and reality.
- **Contingency-related gaps are likely present because large loads can produce system-level impacts in scenarios that differ from those typically included in transient stability studies:** For example, a control misconfiguration or settings error at a large load site could theoretically result in a gigawatt-scale load coming on-line in only a few power system cycles. Thus, it may be necessary to expand the contingencies considered in studies such as those done to meet TPL-001. What these additional contingencies should be is unclear.

Frequency Stability and Voltage Stability

The model- and contingency-related gaps for frequency stability studies and voltage stability studies are similar to those discussed for rotor-angle stability. The primary gaps for frequency stability studies are that the large load modeling practices are insufficiently accurate and commonly considered scenarios may not be sufficiently conservative. These gaps apply both to issues related to frequency stability and managing rate of change of frequency. For voltage stability studies, the dynamic performance of large loads during voltage deviations is the primary area needing better fidelity.

Key Point

The primary gaps for frequency stability studies are that the large load modeling practices are insufficiently accurate and commonly considered scenarios may not be sufficiently conservative.

[75] It is worth noting that the ride-through characteristics of large loads can depend in part on whether the load has a leading or lagging power factor.

Automatic under-frequency load shedding (UFLS) programs are essential for maintaining frequency stability. The disconnection of a large load in a UFLS scenario could exacerbate ongoing reliability issues. For this reason, large loads are inherently difficult to integrate into UFLS programs. Studies need to be performed to evaluate whether the disconnection of that large load could cause further reliability concerns. These studies may need to be performed at interconnection, not just on the five-year Reliability Standard PRC-006[76] UFLS study cycle. Additionally, the five-year PRC-006 UFLS study frequency might not be often enough, because the rapid growth of large loads might significantly change the results of these studies in some areas, even if the large load is not part of the UFLS program.

PRC-006 defines design and documentation requirements for automatic UFLS programs. It intentionally avoids prescribing the method by which utilities meet these requirements. The practices that utilities employ to meet PRC-006 requirements will likely need to be revised. There may also be gaps relating to how automatic UFLS settings are coordinated with any frequency disturbance ride-through requirements to which the large load is subjected via its interconnection agreement.

UFLS entities (the entities that provide automatic load tripping), such as TOs, are required to have available a load-shed amount above a minimum per their PC's UFLS program to ensure that enough load can be shed to arrest frequency decline and avoid complete grid collapse in case of severe low-frequency events. Large loads might not currently be included in UFLS programs. Thus, an interconnecting large load introduces a potential reliability risk that the UFLS entity's existing load-shed amount may fall below the minimum load-shed amount and hence may fail to arrest frequency decline if a severe low-frequency event occurs. The fact that the large load may not be added to the UFLS program may be a gap in utility practices.

Additionally, the manual or UFLS shedding of the entirety of a very large load could lead to over-frequency or overvoltage. The ability to partially shed large loads, either manually or as part of a UFLS scheme, may not be part of existing utility practices.

Undervoltage load shedding (UVLS) programs are an essential tool for mitigating voltage stability problems. The inclusion of large loads in UVLS schemes introduces challenges similar to those associated with their inclusion in UFLS programs. Reliability Standard PRC-010[77] establishes an integrated and coordinated approach to the design, evaluation, and reliable operation of UVLS programs. There may not be any gaps in PRC-010, but there are likely gaps in the ability of existing UVLS design strategies to reliably include large loads.

There may be gaps related to the coordination of UVLS programs and voltage disturbance ride-through requirements placed on large loads. Requiring large loads to remain connected during disturbances such as faults may mitigate rotor-angle or frequency stability problems by better maintaining generation-load balance following system disturbances. However, a large load maintaining full consumption during undervoltage conditions will increase the dynamic reactive power support necessary to maintain voltage stability. Thus, the effects of changes in disturbance ride-through requirements must be considered in UVLS program design. As disturbance ride-through requirements for large loads are being developed in many parts of North America, the coordination of UVLS programs and voltage disturbance ride-through requirements should be considered.

Interconnection Frequency Response

The first portion of the stated purpose of BAL-003-2 is "[t]o require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value."[78]

[76] Available here: PRC-006-5
[77] Available here: PRC-010-2
[78] BAL-003-2

Current calculations for required frequency response (Interconnection frequency response obligation, measured in MW per 0.1 Hz) are based on the margin to the first level of UFLS in each Interconnection but do not separately consider the margin to system over-frequency limits. This is especially important because the considerations and equipment tolerances for over-frequency conditions may be different from that of under-frequency conditions. The assumption that these considerations and equipment tolerances are exactly the same has previously been adequate due to load losses historically being much smaller and less frequent compared to generator losses.

Additionally, large load facilities do not always have good dynamic models showing trip and reduction behaviors and do not always provide the models to all appropriate entities that need them in order to assess potential risks to frequency stability from customer-initiated load reduction events. BAs will need accurate dynamic models in order to reliably assess these risks; therefore, the fact that current models have limited ability to reflect the load reductions is a gap and the fact that accurate dynamic models are not required for all BAs is a gap. The gaps related to load modeling are further discussed in **Chapter 7**.

Additional discussion regarding frequency stability and balancing gaps is provided in **Chapter 4**.

Converter-Driven Stability

Existing practices are unable to adequately define the essential issues underlying converter-driven stability.[79] In order to identify and study a specific converter-driven stability problem, especially at the planning stage (where very little is known about the power converters that will be used by the large load), it is generally necessary to have both a well-bounded idea of the kind of issue at hand and a high-fidelity model that has been designed to replicate the issue. There is currently no clear understanding of the specific kinds of converter-driven stability issues to which large loads will be prone. Without this, study practices and model requirements cannot be effectively defined. Even the most detailed electromagnetic transient (EMT) models must omit some potentially relevant control details.

While this white paper later details gaps relating to high-fidelity modeling (see **Chapter 7**), gaps relating to converter-driven stability should not be viewed as solely, or even primarily, a modeling gap, nor should it be assumed that addressing gaps related to modeling will address gaps relating to converter-driven stability. Many control interactions involving power converters are not identified proactively using studies but rather observed in the field unexpectedly.[80] Often, the control interactions are, by their very nature, the result of inevitable differences between models and reality. These differences may come from minor variations in model implementation, settings errors or device malfunctions, or changes in system or site conditions that take place after the study is performed.

For system owners/operators who have experience with converter-based stability problems, existing practices for managing converter-driven stability primarily consist of identifying system-level factors that have historically proven influential in converter-driven stability issues. The presence of flexible ac transmission system devices, HVdc lines, and IBRs has been a common factor in historical issues with converter-based stability. Weak grid conditions often contribute to the issues. If the presence of these system-level factors is identified, more detailed studies are performed. The proximity of large loads to other large-scale power electronics devices can provide some use baseline for identifying cases of concern, but this criteria is far from the level of detail needed for productive study of the converter-driven stability of large loads.

Converter-driven stability issues are not common and require specialized expertise to analyze. Many system owners/operators may have gaps in their existing practices due to a lack of prior need to analyze such issues.

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[79] See the Stability section of Chapter 3 of the White Paper: Characteristics and Risks of Emerging Large Loads for more information on convertor-driven stability.

[80] See Data Center Power System Stability — Part I: Power Supply Impedance Modeling,
ERCOT experience with Sub-synchronous Control Interaction and proposed remediation,
Large Load Oscillation Event, and
Understanding the Inception of 14.7 Hz Oscillations Emerging from a Data Center

There may be gaps in Reliability Standards such as TPL-001, FAC-001, FAC-002 and MOD-032 relating to study requirements for converter-based stability issues involving large loads. However, until the issues themselves are better characterized, gaps in Reliability Standards defining practices for modeling and studies will be difficult to assess accurately.

Resonance Stability

Many of the gaps discussed in the section on converter-driven stability apply to resonance stability as well. The essential nuance is that resonance stability issues can involve other devices, such as series or shunt capacitors and turbines. The practice currently employed by some system owners/operators is to identify the proximity of the large load to such devices and then initiate detailed EMT studies. However, this is subject to the same drawbacks and limitations associated with current approaches for studying converter-driven stability in large loads.

Forced Oscillations

Large loads can be a source of significant forced oscillations in the 0.1 Hz to 30 Hz range, either as the result of unintended control interactions or as part of their processes (e.g., AI training). There are significant gaps when it comes to defining allowable limits for forced oscillations in terms of BPS reliability. These forced oscillations can excite oscillatory dynamics in the power system, such as electrical resonances, interarea modes, and torsional modes, potentially leading to far-reaching impacts to BPS reliability. However, there are no guidelines or limits by which a system owner/operator can identify that a given forced oscillation is a reliability risk.

Key Point

There are significant gaps regarding the defining of allowable limits for forced oscillations.

IEEE 519 guidance surrounding interharmonics is of very limited applicability; the limits given therein are very stringent, and violations are sufficient only to indicate that nearby users with sensitive loads may experience issues. Power quality violations are not sufficient to indicate an imminent reliability risk, and power quality standards are not intended to be used as a basis for meeting reliability requirements.

Some system owners/operators do conduct screening studies to evaluate whether forced oscillations from proposed large loads might interact with oscillatory modes in the power system, but these are not required by any Reliability Standards, nor are there guidelines regarding what level of interaction is acceptable.

Some system owners/operators do perform oscillation detection and localization in an operational setting and use this to identify oscillating loads. However, adoption of such tools varies widely throughout industry. Again, the lack of acceptable limits for system reliability remains a challenging gap. Even if an oscillating load is identified, there is no established practice for determining whether the oscillation is a risk to reliability and what level of urgency is associated with the issue.

Chapter 6: Security, Resilience, and Event Analysis

While data centers and other emerging large loads have security practices, existing practices, requirements, and NERC Reliability Standards may present security gaps concerning large loads, particularly with the increasing complexity of large loads and their integration of advanced technologies. Reliability Standards are not directly applicable to most large loads as most of them are not NERC registered entities; therefore, the Reliability Standards do not directly provide a minimum level of security measures to be implemented by the large loads. While Critical Infrastructure Protection (CIP) Reliability Standards provide a framework for cyber security, their applicability and granularity concerning the unique operational characteristics and potential vulnerabilities of emerging large loads, such as data centers and industrial facilities with behind-the-meter power generation/microgrids/demand-side management capabilities, may not be fully comprehensive. The growing adoption of internet-connected control systems and the potential for these loads to utilize these control systems introduces new cyber-attack vectors that might not be adequately addressed via current standards or industry protocols. Furthermore, the physical security of these large load sites and their potential impact on grid stability during both normal operations and cyber incidents may require a more holistic and adaptive security approach that goes beyond traditional utility- or ISO/RTO-centric perspectives.

The LLWG has not identified any system restoration gaps related to large loads because large loads will not usually be included in restoration plans. However, if large loads are included in restoration plans, then there are considerations needed to ensure that the load does not impact the stability of the island.

The lack of large load registration can also potentially impact event analysis by making it more difficult to acquire information on an incident. This leads to difficulty in identifying and implementing corrective actions and developing lessons learned for industry. Additionally, there are no Reliability Standards requiring disturbance monitoring equipment. This is a potential gap as high-resolution data provided by disturbance monitoring equipment is essential to monitoring and analyzing the performance of large loads during events such as voltage disturbances and oscillations.

Physical and Cyber Security Gaps

Physical security threats to large loads are diverse, ranging from theft and vandalism to sabotage and insider threats. Environmental factors like severe weather also pose risks. Vulnerabilities often arise from the size and complexity of these loads, extensive perimeters, reliance on cyber-physical systems, aging infrastructure, and human factors. A security gap for some large load categories may be a lack of design basis threat assessments. These assessments define potential adversaries' capabilities and intentions, serving as a benchmark for designing and evaluating security systems. Regular design basis threat reviews are essential to adapt to evolving threats.

NERC Reliability Standards, including CIP-006,[81] CIP-008,[82] and CIP-014,[83] aim to enhance the security and resilience of the BPS. These standards are not directly applicable to large loads since most large loads are not registered entities under NERC's purview. While these standards are also not applicable to generators, the lack of applicability of these standards to large loads may be a gap.

- CIP-006 focuses on the physical security of BES cyber systems, mandating measures like access control, surveillance, and alarm systems to protect against compromise.
- CIP-008 focuses on cyber security incident reporting and response planning.

[81] Available here: CIP-006-6
[82] Available here: CIP-008-6
[83] Available here: CIP-014-3

- CIP-014 specifically addresses physical security for critical transmission equipment and substations, requiring risk assessments and security plans to protect against physical attacks. The benefits of CIP-014 include ensuring grid reliability, reducing risks from physical threats, and building trust in the security of critical infrastructure.

While CIP-014 is a significant security Reliability Standard, areas for improvement or potential gaps may include the depth of risk assessments required and the need for more specific minimum physical protection standards across a broader range of BES assets. This may be a gap related to the CIP Reliability Standards.

Cyber security gaps concerning NERC BPS threats and vulnerabilities might pose significant challenges to the reliability of the electric grid, especially as emerging technologies introduce new risks. Adversaries could exploit vulnerabilities in systems governed by standards issued by standards organizations like the IEEE, the IEC, the National Institute of Standards and Technology (NIST), the International Organization for Standardization (ISO), and NERC. These standards help to safeguard the BPS, but changes to these standards may be needed due to the evolving threat landscape. One critical gap might be in the monitoring and control of interconnected systems such as data centers or energy Internet of Things (IoT) devices employed by large industrial loads (with and without sophisticated microgrids and/or behind-the-meter power generation capabilities). Adversaries could coordinate cyber attacks that might intentionally overload the grid or initiate simultaneous disconnections that might destabilize the system. Similarly, vulnerabilities in IoT devices with BPS applications often lack robust security protocols. This could present a backdoor for cyber attacks that could allow adversaries to impact the BPS.

Data centers also present unique risks due to their massive and variable power demands. [84] Attackers may be able to manipulate workloads, potentially changing the demand of the load. These manipulations fall outside traditional operational parameters and may highlight the gaps in current cyber security frameworks; data center security protocols are not reviewed or vetted via NERC standards.

Communication Security Gaps

Security gaps related to information sharing and data communication protocols for large loads present significant challenges.

- **A primary concern lies in the diverse and often proprietary nature of communication protocols used by different components and systems within a large load infrastructure.** This heterogeneity can create silos of information, which can hinder effective and timely sharing of critical security data, such as sensor readings, access logs, and threat intelligence. Inconsistent data formats and a lack of standardized communication protocols can impede interoperability between security devices and control systems, making it difficult to achieve a holistic view of the security posture.
- **The reliance on legacy communication protocols, which may lack robust encryption and authentication mechanisms, exposes sensitive operational and security data to potential interception and manipulation.** Insufficiently secured communication channels between remote monitoring stations and the large load site may also be a vulnerability, as unauthorized access to these channels could allow attackers to gain insights into operations or even issue malicious commands.
- **The absence of well-defined and enforced data sharing policies, including protocols for incident reporting and information dissemination among relevant stakeholders, could further exacerbate security gaps by delaying response times and hindering coordinated mitigation efforts.**

[84] See White Paper: Characteristics and Risks of Emerging Large Loads for more information on the risks posed by data centers to the BPS:

- **The increasing integration of IoT devices and cloud-based services into large load management introduces new attack vectors and complexities in securing data communication pathways and ensuring data integrity across distributed environments.**

Operational Security Gaps

> **Key Point**
> No NERC standards provide requirements to prevent bad actors from accessing and controlling operational systems related to large loads.

While large loads have security measures implemented, no Reliability Standards provide requirements to prevent bad actors from accessing and controlling operational systems related to large loads and their inherent energy demand profiles. Bad-actor control of a large load could result in excessive ramp rate, oscillations, or other performance aberrations that could impact the BPS. Furthermore, no Reliability Standards provide requirements to prevent an insider threat from accessing operational systems of large loads. Reliability Standard PER-003[85] requires RC, TOP, and BA staff performing reliability-related tasks associated with the respective entity's functions to have NERC certifications. These certifications ensure that staff members are competent in the necessary areas. However, no such standards exist applicable to large loads. Additionally, PER-005 provides requirements for the training of system operators and specific GOP dispatch staff; Reliability Standard PER-006[86] also provides requirements for the training of GOP personnel. Again, no such standards are applicable to large loads.

While multiple Reliability Standards touch upon personnel security and training, the CIP Reliability Standards are the most directly relevant to mandating employee vetting. Reliability Standard CIP-004[87] focuses on minimizing the risk of compromise to BES cyber systems by individuals with authorized access. CIP-004 mandates a baseline level of employee vetting through identity verification and criminal background checks for individuals who have access to critical cyber assets within the North American BPS. This is a crucial component of a layered security approach aimed at mitigating insider threats and ensuring the reliability of the grid. It is important to note that, while CIP-004 is the most direct Reliability Standard addressing employee vetting, other CIP Standards related to physical security (e.g., CIP-006) and access control (e.g., Reliability Standard CIP-007[88]) also have implications for who is granted access to critical facilities and systems, thus indirectly relating to personnel considerations. Lastly, as previously stated, PER-005 focuses on the qualifications and training of personnel but does not specifically mandate the initial vetting process in the same way as CIP-004. Again, these CIP and Personnel Performance, Training, and Qualifications (PER) Reliability Standards are not applicable to large loads.

The lack of requirements for limiting access and control of large loads and for the training of operators of large loads may be a gap in the NERC Reliability Standards.

Existing NERC registered entities rely upon event reporting frameworks within the EOP-004[89] and CIP-008 Reliability Standards to communicate material cyber and physical security event details to regulators and other electric market participants. Large load asset owners have no such mandate related to event reporting for the purpose of grid integrity, reliability, and resilience. This may be an operational security gap.

[85] Available here: PER-003-2
[86] Available here: PER-006-1
[87] Available here: CIP-004-7
[88] Available here: CIP-007-6
[89] Available here: EOP-004-4

System Restoration

The LLWG does not see any gaps regarding large loads in practices, requirements, or Reliability Standards related to system restoration as large loads will not usually be included in restoration plans.

Key Point

Because large loads will not usually be included in system restoration plans, the LLWG has not identified any gaps related to large loads and system restoration.

- The initial loads energized during system restoration are chosen primarily for the purpose of controlling frequency and voltage. Because of the size of large loads and because of the disturbance ride-through characteristics and varying demand of large loads, large loads will likely not be energized in the initial stages of system restoration due to the risk to the stability of the island.
- The choice of loads to restore may be prioritized by criticality, such as loads serving hospitals. Large loads may serve a critical function, but these will likely have backup generation and the need for prioritized restoration would be evaluated on a case-by-case basis.

However, if a large load was included in a system restoration plan, then aspects such as varying demand, disturbance ride-through, and other characteristics of the load need to be studied to ensure that the load does not impact the stability of the island.

Event Analysis and Data Collection Gaps

NERC, the Regional Entities, RCs, GOs, and TOPs typically have standard practices for grid event analysis that require coordination and communication between multiple entities. If additional information is needed for a particular event, NERC, the Regional Entities, and RCs have the ability to send requests for information to authorized representatives of the applicable entities to initiate root-cause analysis and develop mitigation plans when necessary. Registered entities are required to respond to requests for information according to Section 1600 of the NERC ROP.[90] If the analysis of the event uncovers potential violations of existing Reliability Standards, regional requirements, or utility best practices, the applicable entity can be required to develop and implement a corrective action plan to mitigate the potential of similar future events.

Lack of LSE and large load registration can impair event analysis of incidents involving large loads. Multiple events in the Eastern Interconnection (EI)[91] and ERCOT[92] have involved large loads reducing significant amounts of load during voltage disturbances; data center oscillations have also been observed.[93, 94] The significant gaps in existing practices, requirements, and standards can impair NERC and the Regional Entities from obtaining the needed information directly from the large load entities to perform thorough root-cause analysis on these events. Therefore, it is difficult to identify and implement proper corrective actions and develop lessons learned to prevent additional events.

There are existing Reliability Standards and regional requirements for GOs and TOs regarding disturbance monitoring and reporting requirements. Examples include Reliability Standards PRC-002[95] and PRC-028 and ERCOT Nodal Operating Guide[96] Section 6.1. These standards and requirements mandate the installation and configuration of disturbance monitoring equipment (DME) such as digital fault recorders, dynamic disturbance recorders, and phasor measurement units. Standards include location requirements and requirements to provide data to requesting entities such as NERC, the Regional Entities, and RCs within specified timelines. ERCOT revised Nodal Operating Guide Section

[90] Available here: Rules of Procedure
[91] See Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions
[92] See *ERCOT Large Load Loss/Reduction Events 2020-2024* presentation from the December 12, 2024, NERC LLTF meeting. December 2024 LLTF meeting presentations available here: https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_presentations_december_12_2024.pdf
[93] See Understanding the Inception of 14.7 Hz Oscillations Emerging from a Data Center
[94] See Data Center Power System Stability — Part I: Power Supply Impedance Modeling
[95] Available here: PRC-002-5
[96] Available here: Current Nodal Operating Guides

6.1 in 2024 to state that the interconnecting TOP of a large load with peak demand greater than or equal to 75 MW must install and configure DME upon request from ERCOT. However, since this requirement does not exist in NERC standards, there is a potential gap in assessing and mitigating the operational risks of large loads. High-resolution data provided by digital fault recorders, dynamic disturbance recorders, and phasor measurement units is essential to monitoring and analyzing the performance of large loads in events involving large load loss during voltage disturbances and oscillations.

Chapter 7: Modeling of Large Loads

Numerous postmortem analyses of grid events have underscored the necessity of modeling loads with precision to accurately re-create the evolution of these events. The composite load model is the most advanced version of load modeling used for bulk system reliability analysis. EMT models of loads have also been used frequently for specialized assessments, focusing on higher frequency dynamics and harmonic evaluations. Historically, modeling efforts have concentrated on improving representations of three-phase and single-phase motors, which constitute the largest portion of system load in terms of installed megawatt capacity. However, recent years have witnessed significant growth in large load facilities that differ markedly from traditional industrial load. These new types of loads are not only substantial in size but also predominantly consist of numerous rectifiers that supply power to the end process, contrasting sharply with traditional industrial loads dominated by large induction or synchronous motors. This shift has introduced two major challenges. Firstly, existing phasor domain load models, such as composite load models, are not equipped to accurately represent large power electronic rectifier-driven loads.[97] Secondly, even if suitable models were developed, there is a lack of information necessary for engineers to properly parameterize these models. The recent events in ERCOT,[98] the EI,[99] and EirGrid[100] have demonstrated that these devices can operate in ways that put the system reliability at risk. Therefore, accurate models for these devices that reliably predict their behavior are essential for maintaining grid stability and reliability. This chapter documents industry's needs and gaps related to the modeling of emerging large load facilities.

Key Point

Even if the needed phasor-domain large load models were developed, there is still a gap in information necessary to properly parameterize the models.

Modeling Philosophy and Terminology

Before discussing modeling gaps, it is important to acknowledge that models of physical systems are never perfectly accurate. Instead, models aim to capture the phenomena of interest related to a physical system as accurately as possible to aid in decision-making through simulation studies. Furthermore, in the context of power system dynamic assessments, a single simulation platform is generally not suitable for all types of assessment; simulation tools are selected depending on the type of dynamics. The use cases of various simulation tools, as well as the common terminologies related to power system modeling and how these are applied to reliability risk assessments, are discussed in **Appendix A**. To define modeling gaps, the common terminologies related to power system modeling and how these apply to reliability risk assessments must be understood.

Gaps in Model Availability

It is worthwhile to discuss model availability gaps separately for phasor domain (or positive sequence models) and EMT models.

Phasor Domain or Positive Sequence Models

As mentioned earlier, until the past few years, the load modeling space was mostly focused on modeling single-phase residential air-conditioning systems, known to cause fault-induced delayed voltage recovery. The composite load model that is currently used by most utilities is extremely simplistic for electronic loads. The simplified electronic load

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[97] The EV charger model developed by the Electric Power Research Institute does allow for modeling some aspects of large power electronic rectifier-driven loads. Additionally, after the initial drafting of this paper, the Power Electronic Reconnecting and Ceasing (PERC1) model was developed and is the most state-of-the-art model for large power-electronic loads. While the modeling gaps identified in this paper were accurate when the content of this paper was initially being drafted, some of the gaps may be reduced with the new PERC1 model.

[98] See *ERCOT Large Load Loss/Reduction Events 2020-2024* presentation from the December 12, 2024, NERC LLTF meeting. December 2024 LLTF meeting presentations available here: https://www.nerc.com/globalassets/who-we-are/standing-committees/rstc/llwg/lltf_presentations_december_12_2024.pdf

[99] See Incident Review - Considering Simultaneous Voltage-Sensitive Load Reductions

[100] See *CIGRE/IEEE Webinar – Large Loads and Their Impact on the Grid an Emerging Reliability Risk* presentation, available here: https://cigre-usnc.org/wp-content/uploads/2025/05/NGN-Webinar-May-21-2025.pdf

model was sufficient when the majority of the electronic loads on the system were consumer electronic equipment such as computers and televisions. However, this model is insufficient when trying to model the behavior of large loads, which are now dominated by power electronic rectifier systems. Industrial UPS systems, large industrial rectifiers such as electrolysis power supply equipment, and large power electronic motor drives have sophisticated controls; their ride-through during disturbances cannot be modeled using an electronic load component in the composite load model.

In 2022, the Electric Power Research Institute, with funding from the Lawrence Berkeley National Laboratory, developed a positive sequence model for aggregated representation of vehicle chargers.[101] This model (see **Figure 7.1**) allows some more flexibility in modeling the disconnection and reconnection of electronic loads. Some studies have used this model to investigate the impact of data center disconnection.[102] However, much work is still needed to accurately model data centers. Key gaps that need to be bridged are as follows:

- **Rectifier Dynamics Representation**: The dynamics of the rectifier are currently represented by simple first-order transfer functions in this model; this is based on the assumption that loads will have stable control and that only the slower dynamics are relevant in the positive sequence. Although validated using some lab test results for electric vehicle (EV) chargers and EMT models, it still needs to be compared against a wide array of large rectifier performances (e.g., industrial UPS, electrolysis power supply equipment) to confirm whether the simplification is appropriate.
- **Control Logic Limitations in Existing Models**: The control logic in the model was primarily designed to replicate the observed disturbance ride-through behavior in EV chargers. It may not be sufficient to replicate the behavior of UPSs or other power electronic equipment. It is also unclear whether a single model will be adequate or if multiple power electronic models are needed.
- **Cyclic Load Injection**: Some large load facilities, such as AI training data centers, have cyclic load injections that this model cannot replicate.
- **Collocated Generator and Battery Dynamics**: The model cannot capture the dynamics of any collocated generator or battery energy storage systems.
- **Library Model Availability**: Importantly, the model is not available as a library model in any simulation tool other than GE PSLF.™

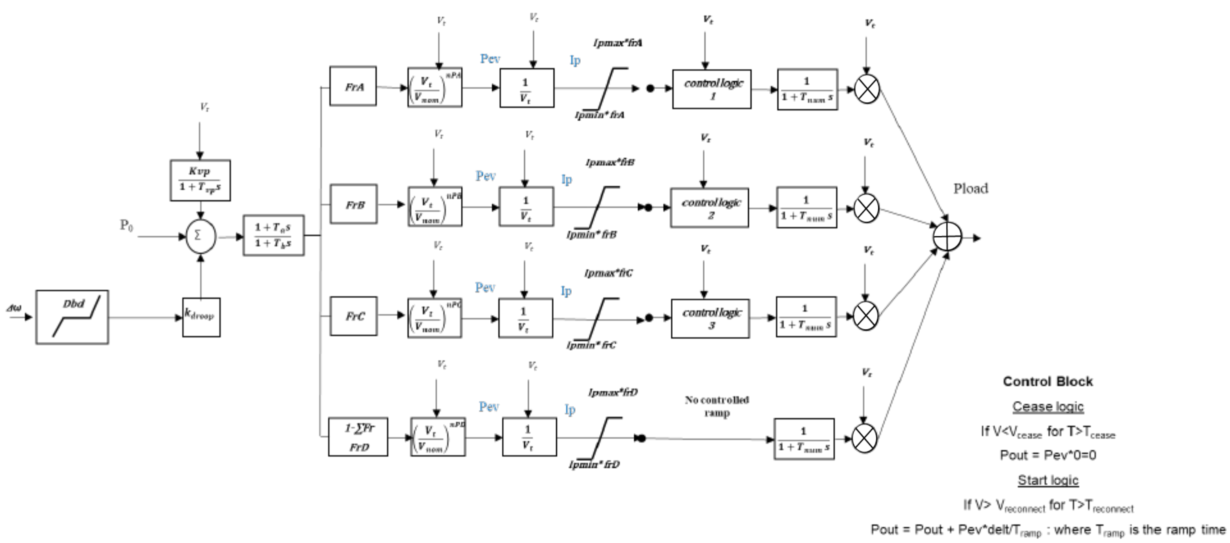

Figure 7.1: Active Power Loop for the Aggregated EV Charger Load Model

[101] A Positive Sequence Model for Aggregated Representation Electric Vehicle Chargers
[102] See Impact of Large Load Disconnection on System Stability 2024 Grid of the Future Symposium 1

EMT Models

Unlike positive sequence tools, EMT tools do not have library models of loads. Rather, EMT tool libraries have a wide array of motor models as well as power electronic device models that can be used to create complex load model structures. Generic structures for models are also available via some tools; these models can be customized as needed. In that respect, a particular model availability gap does not exist for EMT. However, generic structures for large load facilities are not readily available, which might present a roadblock for someone without significant expertise in EMT to create such a model on short notice.

A key gap in EMT model availability lies in the absence of standardized guidelines for modeling different components of large load facilities. For IBRs, IEEE 2800 Section G.4 provides dynamic modeling data requirements for EMT models of IBRs, including accuracy, usability, and efficiency features. For example, under model accuracy features, it specifies that sufficient detail should be included to represent the different components of an IBR plant. These requirements ensure that EMT models for IBRs are accurate, practical, and efficient for use in a wide range of studies. As another example, SPP publishes an EMT Model Requirements document that sets detailed standards for IBR models. This guidance covers aspects such as model accuracy, usability, and simulation performance.[103] However, no comparable standard or guideline exists for modeling large load facilities, which can consist of multiple UPS systems, variable frequency drives, and other power electronic components. Without clear guidance, vendors might be uncertain about the level of detail required in their developed models and could include insufficient detail, potentially reducing the accuracy and reliability of the overall facility model. Establishing standardized modeling requirements for large loads would address this gap, enabling the development of more reliable EMT models.

Gaps in Modeling Information

While the previous section discussed the unavailability of library models, another significant challenge is the lack of information about equipment in large load facilities. Traditionally, industrial load models have been developed based on survey data collected by NERC or regional working groups. For large load models, facility models have been developed based on the available literature, which is quite generic. However, the existing information is insufficient for new large facilities for several key reasons:

- **Limited Experience with Newer Facilities**: The industry lacks significant experience with newer large load facilities like data centers and hydrogen electrolysis plants. Utility engineers are often unfamiliar with the types of equipment used in these facilities to support the main processes. For example, in a data center, the UPS can operate in a double conversion mode, where the grid supply always passes through the UPS, or in an eco-mode (see **Figure 7.2**), where the grid supply is bypassed when the voltage is above a certain threshold. Similarly, for hydrogen electrolysis facilities, the power supply equipment could be either thyristor- or insulated gate bipolar transistor-based, depending on the size and type of electrolysis stack being used. These details are crucial for developing accurate models.

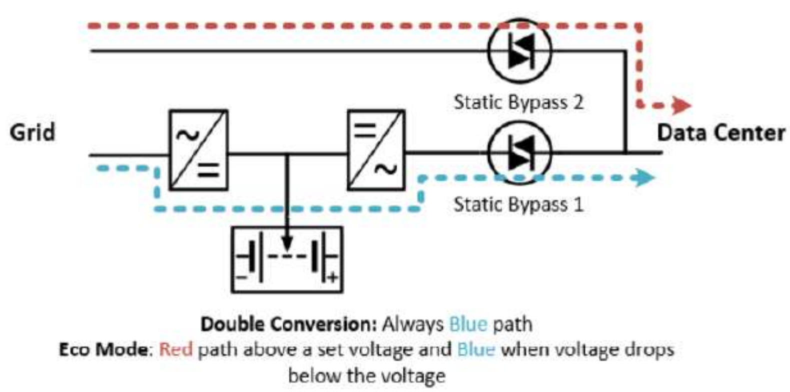

Figure 7.2: Double Conversion vs. Eco Mode Operation of Static UPS

[103] SPP EMT_Model_Requirements_R1

- **Balance of Plant Modeling**: Apart from the main process, modeling the balance of plant, such as cooling loads for data centers and pumps and compressors for hydrogen electrolysis facilities, is essential. Information about balance of plant equipment is not readily available.
- **Highly Controllable Equipment**: Large load facilities like data centers are equipped with UPSs and other power conditioning equipment that are highly controllable and have voltage-sensitive grid disconnection thresholds. Accurately modeling the disturbance ride-through behavior of such facilities for grid studies requires TPs and utility engineers to understand how these devices detect grid anomalies and the thresholds that trigger grid disconnection and transfer of load to local backup. Such information is not readily available for inclusion in models.
- **Variable Load Patterns**: Loads such as AI training facilities create spiky (**Figure 7.3**), variable load patterns that can impact power system reliability and need to be modeled. Information about these load patterns is not readily available for inclusion in models. Furthermore, some facilities have battery energy storage systems that operate in parallel to smooth the spikes. Having information about such configurations and their control methods will be essential for developing facility models for large loads.

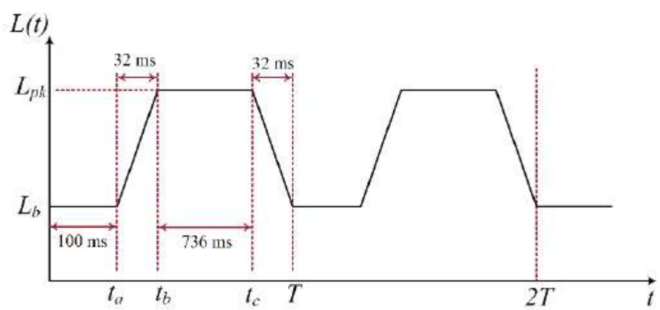

Figure 7.3: Possible AI Training Load Profile[104]

The lack of proper information presents a significant challenge for the modeling community. Without detailed information, even if models could be created, the models can never be parameterized properly for the purposes of any reasonable assessment. The gaps in modeling information are primarily due to the following:

- There are no requirements in the NERC standards specifically for load facility owners to submit validated models (or just models) to the relevant TPs. The responsibility of modeling a load facility lies with the TPs.
- Since load facility owners are not required to submit models, they might not participate in industry forums where load modeling is discussed. As such, avenues for interactions between the load modeling community and load facility owners may be very limited.
- Load facility owners may not have a clear idea as to the requirements of grid modeling. Load modeling for assessing the issues within a load facility/process is quite different than the concerns that grid engineers have and the model requirements are different.
- TOs do not always have clear data and model sharing requirements for the large loads. Additionally, large loads may be unfamiliar with utility coordination requirements.
- Large loads may be unwilling to share information due to data sensitivity concerns.

Gaps in Modeling Guidance and Practices for Large load Facilities

Since large load facilities have multiple components, guidance on how these facilities should be modeled for different studies is needed. Similar guidance has been issued in the past for modeling of wind and photovoltaic plants in phasor domain simulations. The lack of adequate guidance for modeling large load facilities needs to be addressed.

[104] Grid-Forming Inverter Applications for Improved Reliability and Power Quality in AI Data Centers

As mentioned before, EMT studies are not currently suitable for large-scale grid simulations. However, EMT studies will be increasingly important for large load facilities to ensure that the risks requiring specialized EMT modeling (e.g., resonance stability, converter-driven stability, and forced oscillations occurring at frequencies >5 Hz)[105] can be evaluated. Hence, screening methods for determining the need for EMT evaluations are necessary. Some of these screening techniques exist for IBR and HVDC interconnections that can be leveraged; however, these need to be evaluated for large load interconnections as well. Additionally, guidance on the level of modeling details needed and where aggregated modeling is acceptable in EMT simulations with large load facilities is important. The lack of adequate guidance in this area is a gap that needs to be addressed.

Traditionally, loads have not been modeled in short-circuit studies as their impact to fault currents has usually been negligible. However, the lack of representation of large load behavior during faults, particularly under weak grid conditions, may present a gap in current short-circuit and protection analysis practices. These loads can significantly impact voltage and current waveforms during disturbances, potentially compromising the accuracy and dependability of protection systems. Incorporating their dynamic characteristics into fault analysis may be important for improving the reliability and security of protection schemes in evolving grid conditions.

Gaps in Modeling Validation and Model Quality Tests

Model validation plays an important role in ensuring that the developed models are a reasonable representation of the dynamic responses of the actual devices. GOs are required to submit model validation reports on a regular basis to fulfill the requirements of Reliability Standards MOD-026[106] and MOD-027.[107] The models are validated based on staged tests[108] or based on measurements from grid disturbances.[109] Model validation has also been found to be necessary for IBRs. However, such practices are not commonplace for loads.

Load models are often validated as part of the Reliability Standard MOD-033[110] assessment; however, the MOD-033 assessment is not explicitly meant for loads but for overall system model validation. This practice was considered sufficient as loads were smaller in size and distributed across the grid. However, the advent of emerging large loads changes this assumption and model validation becomes important. For loads, model validation has a few challenges that need to be overcome:

- No standard exists today that would require a load facility owner or LSE to perform a regular model validation exercise. As such, the burden of parameterizing load models falls on TPs and is only done during the load interconnection process and fine-tuned or modified during event validation.
- Even if a model validation standard is in place, the same process as exists for generators cannot be adopted. Staged tests are generally not possible in a load facility like the exciter step response tests that can be conducted in power plants. Load model validation would then have to rely on grid disturbances. Furthermore, frequent events like single line-to-ground (SLG) faults or shallow voltage sags may not be able to excite all relevant controls in a facility to be able to model those controls.
- Proper measurement devices with desired sampling rates might not be deployed on the grid at preferred locations that would allow a modeler to isolate the response of a single facility and be able to validate the relevant models.

Model quality testing is a process used to screen dynamic models, typically IBRs, for completeness and stability before incorporating them into planning cases. The goal is not to verify a model's accuracy against real-world performance

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105 See Data Center Power System Stability — Part I: Power Supply Impedance Modeling | CSEE Journals & Magazine | IEEE Xplore
106 Available here: MOD-026-1
107 Available here: MOD-027-1
108 See Automated parameter derivation for power plant models based on staged tests | IEEE Conference Publication | IEEE Xplore
109 See Power plant model validation for achieving reliability standard requirements based on recorded on-line disturbance data | IEEE Conference Publication | IEEE Xplore
110 Available here: MOD-033-2

but to ensure that it initializes correctly, responds reasonably to disturbances, and does not cause convergence or stability issues during simulation. These tests help maintain the integrity of system-wide base cases and reduce the risk of unreliable behavior in planning studies. While model quality testing is now standard practice for IBRs, there is no consistent industry approach for applying similar screening to large loads, creating a gap in how these resources are evaluated. This becomes increasingly important as fast-acting, transmission-connected loads, such as data centers, cryptocurrency mining facilities, and industrial facilities, become more prevalent and start to influence overall system behavior. Some operators have developed detailed model quality testing procedures for generators. For example, ERCOT publishes a Model Quality Guide[111] that outlines expectations for model structure, initialization behavior, simulation response, and performance under fault conditions. The process includes verification methods, such as comparison to field-measured parameters via a parameter verification report or unit model validation, to ensure that the submitted model reflects the behavior of the physical resource. These layers of screening help prevent overly idealized models from being accepted into study cases. Similar practices are not currently applied to large loads, even when their modeling could materially impact study outcomes.

[111] Available here: https://www.ercot.com/services/rq/re

Chapter 8: Risk Categorization and Mitigations

This white paper discusses the gaps in existing Reliability Standards, practices, and requirements. However, the solution to address each gap may not always be to update the specific Reliability Standard, requirement, or process that has the gap.[112] The mitigations used should be tailored based on the likelihood or severity of a BPS impact from the risk. To help determine proper mitigations for each of the risks, this chapter describes the likelihood and impact of the risks and whether those risks can be adequately mitigated by the existing registered entities. Most of the risks discussed in this chapter are based on the risks provided in Chapter 4 of the LLTF *Characteristics and Risks of Emerging Large Loads* white paper.[113] For the risks that the LLWG has determined cannot be mitigated by existing registered entities, this chapter also provides information regarding what is needed from a potential new registered entity to adequately mitigate the risk. The detailed discussions are provided in the **Risk Likelihood/Impact and Ability to Mitigate** section of this chapter.

The NERC *Framework to Address Known and Emerging Reliability and Security Risks*[114] document provides direction regarding how the risks from emerging large loads should be addressed. The LLWG recommends that this framework document is utilized to determine appropriate risk mitigations. **Figure 8.1** provides a visual overview from this framework document of the mitigations that should be used based on the likelihood and impact of a risk.

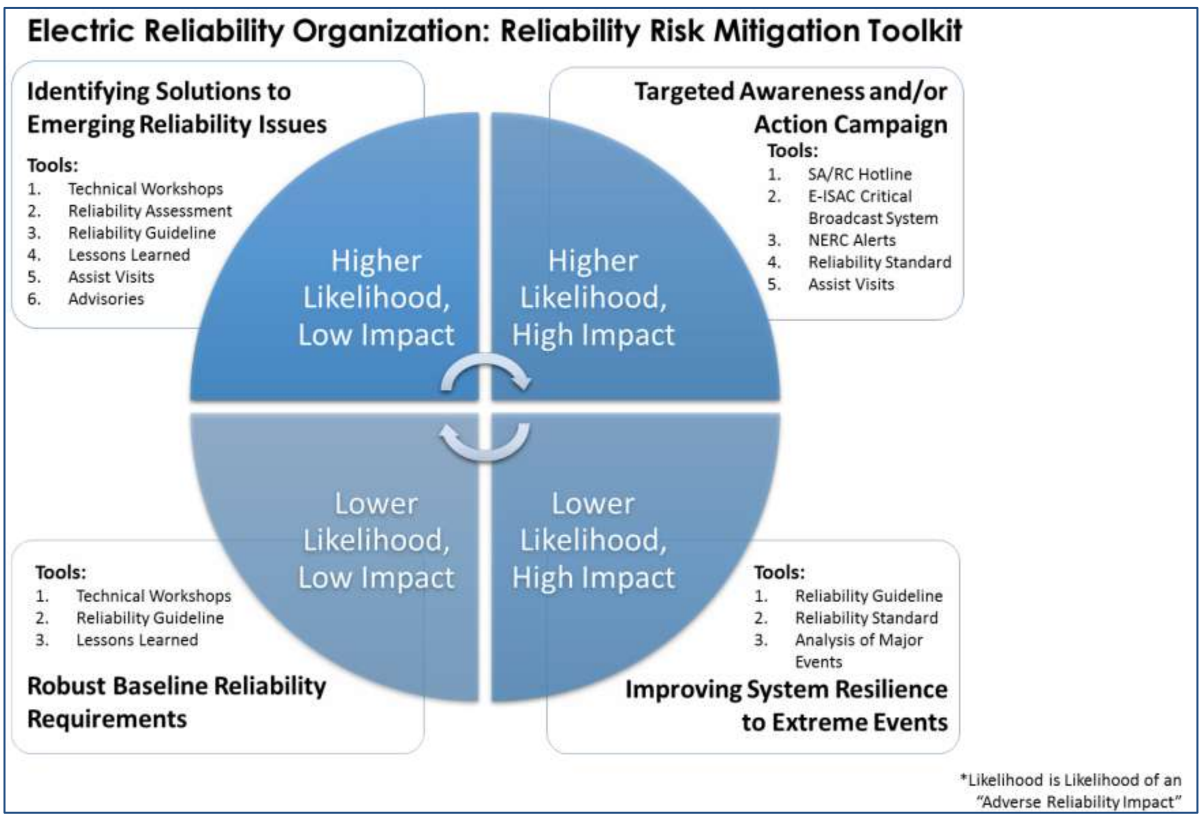

Figure 8.1: ERO Reliability Risk Mitigation Portfolio

[112] For example, this paper has found that there are gaps related to emerging large loads in BAL-001, BAL-002, and BAL-003; however, accurate load modeling data and enforced disturbance ride-through requirements could help reduce the need for updates to the BAL Reliability Standards and help address risks such as voltage stability.
[113] Available here: White Paper Characteristics and Risks of Emerging Large Loads
[114] Available here: Framework to Address Known and Emerging Reliability and Security Risks

Figure 8.2 provides a similar figure as shown above, populated based on the findings in this chapter. The LLWG hopes that this will be useful as its recommendations are prioritized. The findings in this chapter have informed several of the recommendations provided in the Conclusion. Specifically, the risks with the following risk categorizations have been identified as needing to be addressed with Reliability Standards and this is reflected in Recommendation 2 in the Conclusion:

- High impact risks
- High likelihood risks
- Moderate likelihood, moderate impact risks

All risks discussed in this chapter, except for the System Restoration risk (which has been determined to not have any associated gaps), have been identified as needing to be addressed with Reliability Guideline(s) and this is reflected in Recommendation 3 in the Conclusion. Additionally, for the risks that existing NERC registered entities are not able to address, as discussed later in this chapter, the specific actions needed from a new type of registered entity(ies) are provided and are listed in Recommendation 1 in the Conclusion.

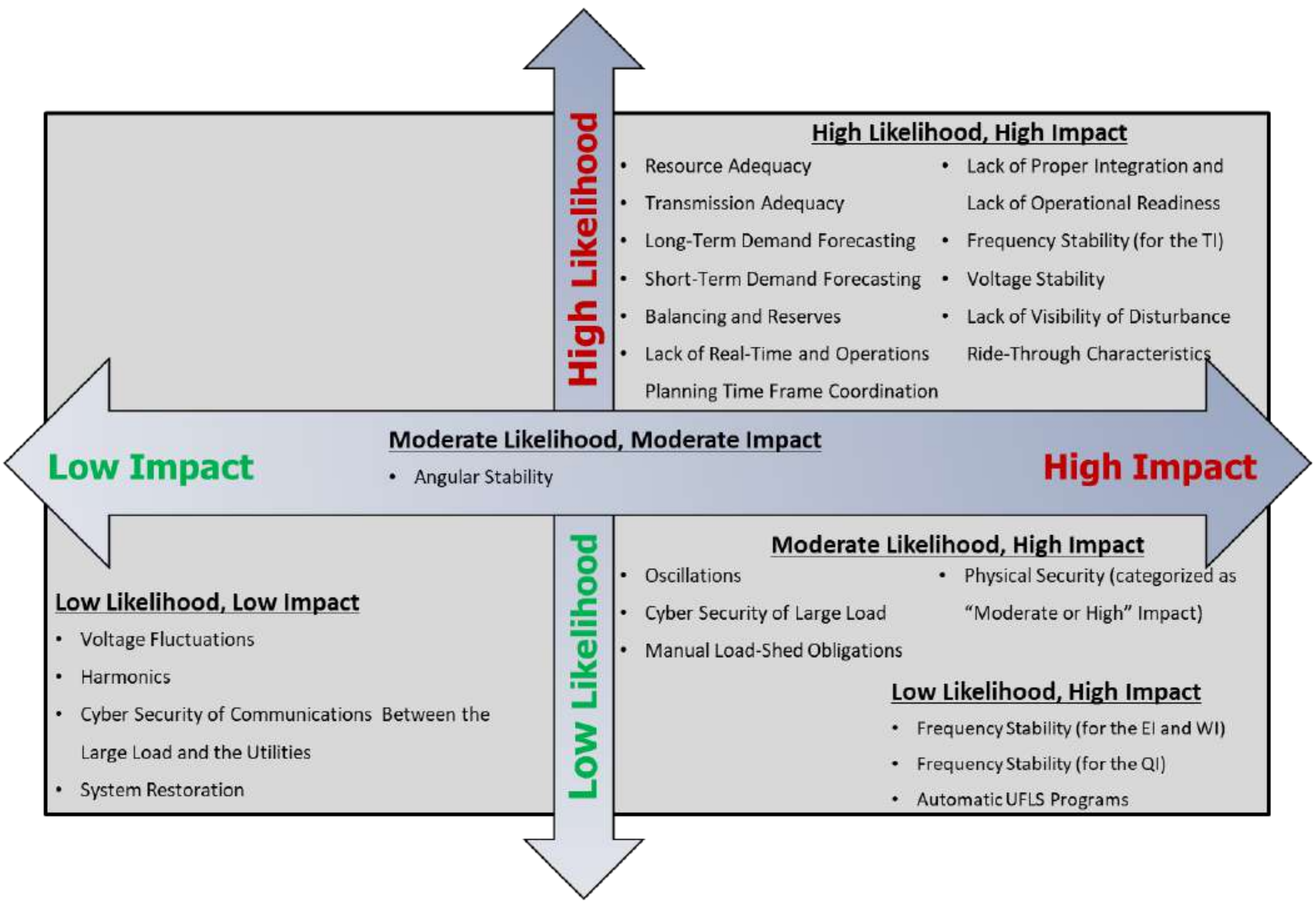

Figure 8.2: Likelihood and Impact of BPS Risks from Emerging Large Loads

For this white paper, risk likelihood and risk impact severity are defined as follows:

- Risk **likelihood** is defined in terms of the qualitative[115] probability that an event from a given risk category causes a measurable adverse reliability impact. [116] For example, harmonics are present to some extent across the entire BPS. However, this does not mean that harmonics are necessarily a high-likelihood risk—it is seldom the case that harmonics cause attributable damage to BPS equipment or result in forced outages. It is often the case that events from a particular risk category can manifest in different ways, each with a different impact severity. For example, an angular instability event could consist of a single generator disconnecting or unintentional islanding (and potential subsequent blackout) of a large region of the grid. In such cases, the likelihood rating should represent a blend of the different possible outcomes, weighted according to the impact.
- Risk **impact** severity is defined in terms of the adverse impact to the reliability of the BPS.[117] For example, an event that causes the forced outage of a single generator has a low impact, as this is a routine disturbance that the BPS is designed to withstand. On the other hand, an event that results in sudden forced outages for several dozen transmission lines has a high impact as the BPS is not designed to operate with so many assets unexpectedly out of service and may experience a collapse resulting in region-wide power outages.
- Within this white paper, there are nuances that must be handled through industry consensus among subject-matter experts. One such example is the relationship between the **duration** of a forced outage and impact severity: Whether a generator is tripped off-line by disturbance ride-through protection or because it has experienced a catastrophic turbine shaft failure, the immediate impact on the BPS is much the same—one generator is removed from service. However, the shaft failure is clearly a much more impactful event overall: The generator will be out of service for quite some time owing to repairs that require a large duration of time to implement. The capacity constraints introduced by a long-term forced generation outage can result in the BPS becoming less resilient to future disturbances. Thus, it is inappropriate to treat generator tripping and turbine shaft failure as equivalent reliability impacts.

A key consideration when determining the ability of existing registered entities to mitigate many specific risks is to determine the ability to mitigate them through interconnection requirements. Many of the requirements that are needed for large loads, such as disturbance ride-through and modeling requirements, can be placed in TO interconnection requirements via FAC-001. However, interconnecting utilities generally do not have the authority to assess performance-based financial penalties except under certain very limited circumstances. Therefore, depending on the significance of the impact from the risk, interconnection requirements may not adequately mitigate the risk; directly enforceable NERC standards may be needed instead. For generators, there are risks that are currently addressed via NERC standards, rather than only through interconnection requirements; examples of this are the frequency and voltage disturbance ride-through requirements found in NERC standards. Additionally, NERC standards provide consistent performance requirements across the BPS, while interconnection requirements can vary between TOs or regions; with that being said, interconnection requirements can have consistency if they are a result of NERC standards applicable to the TOs. A further argument supporting NERC standards being more appropriate than interconnection requirements for addressing significant BPS risks is that, if large loads, LSEs, or a similar entity do not have NERC standards directly applicable to them, the existing registered entities will then be responsible for the performance of the large loads. While this may have been appropriate for historical loads of significant size, emerging large loads are comparable to the size of significantly large generators and have unique operational characteristics, both of which create challenges for having a third party be responsible for their performance. Last, enforcement of interconnection procedure/agreement terms and conditions may vary, while enforcement mechanisms that exist for the NERC standards provide clarity.

[115] While assessments of probability are usually quantitative in nature, the assessments of risk likelihood in this chapter were developed based on the experience-based judgement of the paper contributors.
[116] Per the NERC Glossary of Terms Used in NERC Reliability Standards, adverse reliability impact is defined as "[t]he impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection."
[117] *Ibid.*

This chapter considers whether or not existing NERC registered entities can address the BPS risks presented by emerging large loads, and the language provided assumes that NERC standards are the more appropriate mechanisms for this risk mitigation for significant risks, as opposed to interconnection requirements. If it holds that NERC standards are the more appropriate mechanism, it may necessitate the registration of large loads or LSEs in order for these standards to be directly enforceable. However, if interconnection requirements are seen as being more appropriate for addressing specific gaps, the LLWG's opinion in this area may change and this may reduce the need for registration of these new entities.

Figure 8.3 provides a conceptual overview of the types of large loads that may become registered entities if, in order to address the risks posed by data centers and cryptocurrency mining facilities, (1) all large loads were registered, (2) power electronic-interfaced loads were registered, or (3) loads with a significant amount of IT equipment load were registered. As shown in the figure, registration of all large loads or registration of power electronic-interfaced loads would include other large loads in addition to data centers or cryptocurrency mining facilities.

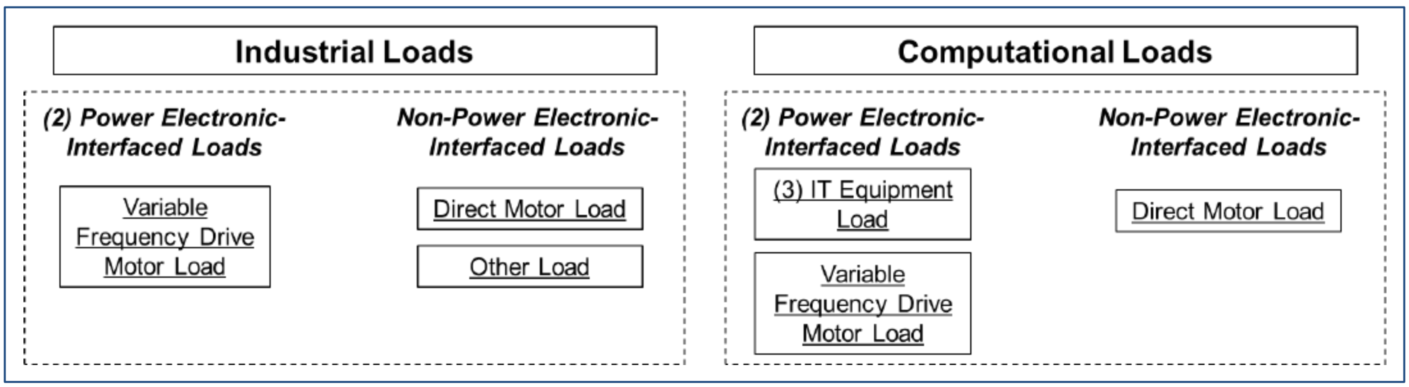

Figure 8.3: Load-Type Conceptual Overview

Risk Likelihood/Impact and Ability to Mitigate

Long-Term Planning Risks

Resource Adequacy

The impact of the Resource Adequacy risk is **high** because if the amount of load that needs to be served is close to or greater than the amount of available generation, then frequency stability may be at risk. Although work is being done in this area, many regions do not currently perform resource adequacy checks before connecting a large load. The likelihood of a reliability impact from this risk is **high** because generation can take a long time to build and data centers can come on-line very quickly. Additionally, load forecasts over the next 10 years show rapid load growth, with data centers accounting for most of the demand growth according to the 2025 NERC LTRA. Additionally, this LTRA has flagged several areas as high risk ("[i]n high-risk areas, planned resources…would result in energy shortfalls that exceed resource adequacy targets or baseline criteria for unserved energy or loss of load") starting within the next 5 years.[118]

This risk can be mitigated with existing registered entities. While information on large load location, timing, size, operational flexibility, likelihood of materialization, and other variables is needed significantly earlier than the energization date (years before the energization date), this can be obtained by existing registered entities by requiring this information with enough lead time in interconnection requirements; the TO could require that delays in the provision of necessary data by load entities result in delayed energization of load or delayed ramping of load. This information would need to be provided to the RPs by the TOs.

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Transmission Adequacy

The impact of the Transmission Adequacy risk is **high** because if the amount of load that needs to be served is greater than the available transmission capacity, then the transmission system is being run closer to its limits with respect to bulk power flows resulting in exacerbated stability risks due to increased voltage angle differences across transmission lines, increased voltage magnitude differences across transmission lines, or other factors. The likelihood of a reliability impact from this risk is **high** because large loads can come online quickly and exhibit unique system behaviors that need to be accurately modeled. Moreover, building transmission and coordinating outages require significant time, which must be studied and considered when validating the expected in-service dates of new transmission.

This risk cannot be adequately mitigated with existing registered entities. In the steady-state domain, the existing NERC registered entities have the tools to manage these thermal and voltage violations. TPs and PCs have processes in place to manage transmission expansion and resolve violations that are discovered in the planning process. During real-time operations, TOPs, RCs, and BAs can manage thermal and voltage violations by preventing load energization, re-dispatching generation, performing transmission switching, or performing load shedding. While information on large load location, timing, size, operational flexibility, likelihood of materialization, and other variables is needed significantly earlier than the energization date (years before the energization date), this can be obtained by existing registered entities by requiring this information with enough lead time in interconnection requirements; the TO could require that delays in the provision of necessary data by load entities result in delayed energization of load or delayed ramping of load. This information would need to be provided to TPs (and others) by the TOs. However, in the dynamics domain, the existing NERC registered entities do not possess the detailed information about the large load facility design and cannot build accurate dynamic models for simulations without the information possessed by large load entities. Without Reliability Standards ensuring that the dynamic modeling information provided by loads is accurate, there is concern that the information provided might not be accurate enough. Therefore, this risk cannot be adequately mitigated by existing registered entities.

To adequately mitigate the Transmission Adequacy risk, the following is needed from new type(s) of registered entity(ies):

- Provide accurate information (as accurate as possible and as early as possible) regarding large load dynamic model to support interconnection and transmission planning studies
- Inform the TP and TO and/or other applicable entities of any pertinent changes to the characteristics of the load

Long-Term[119] Demand Forecasting

The impact of the Long-Term Demand Forecasting risk is **high** because if the long-term demand forecasts are inaccurate, adequate amounts of generation might not be built to serve the load. This could result in frequency stability being at risk. Additionally, inaccurate long-term demand forecasts could lead to transmission adequacy risks. There is an influx of large loads with various amounts of certainty or uncertainty. There is not a process to determine how much of the load will materialize. The likelihood of a reliability impact from this risk is **high** because load forecasts over the next 10 years show rapid load growth, and the load forecasts are changing as well. There is a large difference between the higher and lower load forecasts, showing a large amount of uncertainty in the expected load growth.

This risk can be mitigated with existing registered entities. While information on large load location, timing, size, operational flexibility, likelihood of materialization, and other variables is needed significantly earlier than the energization date (years before the energization date), this can be obtained by existing registered entities by requiring this information with enough lead time in interconnection requirements; the TO could require that delays in the

[119] i.e., later than operational

provision of necessary data by load entities result in delayed energization of load or delayed ramping of load. This information would need to be provided to the demand forecasters by the TOs.

Operations/Balancing Risks

Short-Term[120] Demand Forecasting

The impact of the Short-Term Demand Forecasting risk is **high** because large loads such as data centers are known to fluctuate rapidly and it is known that their demand is difficult to forecast. The variability can also cause significant electricity market price impacts that can in turn impact the forecast. The large size of the load can have a significant impact on the local resource dispatch needs because of the relative size of the load compared to the area. There is also a lack of history to help inform forecasting. The likelihood of a reliability impact from this risk is **high** because large loads such as data centers are known to have varying demand and it is known that their demand is difficult to forecast. The high ramping frequency of some large loads can be difficult to capture with existing forecasting models and data processes, as well as generator automatic generation control.

This risk cannot be adequately mitigated with existing registered entities. Accurate short-term demand forecasts of large loads will likely often require the large load to participate in the developing of the forecast. This coordination could occur without requirements for the large load. However, because of the importance of short-term demand forecasts, this coordination likely needs requirements enforcing it.

To adequately mitigate the Short-Term Demand Forecasting risk, the following is needed from new type(s) of registered entity(ies):

- Provide sufficient data to applicable entities (e.g., RC, TOP, and BA) for the development of short-term demand forecasts
- Provide accurate short-term demand forecast data

Balancing and Reserves

The impact of the Balancing and Reserves risk is **high** because the large amount of demand variability that large loads such as data centers can have can lead to exhaustion of operating reserves (spinning). The likelihood of a reliability impact from this risk is **high** because large loads such as data centers are known to have rapid, unexpected demand variations. This characteristic of data centers is very well known.

This risk cannot be adequately mitigated with existing registered entities. Gaps related to short-term demand forecasting are discussed earlier in this paper.[121] Lack of accurate short-term demand forecasts for the large loads could be very impactful to the ability to balance generation and load because these loads are expected to become a significant portion of system load. However, existing registered entities cannot get accurate short-term demand forecast data.[122] Additionally, ramp rate limits on large loads, along with real-time coordination as previously discussed, are important for effective ACE management. Ramp rate limits, developed in consultation with the BA, must ensure that sufficient high-speed reserves are dedicated to managing high intra-hour and intra-minute volatility. However, because interconnection requirements do not currently require TOs to coordinate with BAs in their development, a strong mechanism is needed to obtain ramp rate limits.

[120] (operational)
[121] See Chapter 4.
[122] See the Short-Term Demand Forecasting sub-section of this chapter for more information.

To adequately mitigate the Balancing and Reserves risk, the following is needed from new type(s) of registered entity(ies):

- Provide sufficient data to applicable entities (e.g., RC, TOP, and BA) for the development of short-term demand forecasts and operating plans
- Provide accurate short-term demand forecast data
- Ensure compliance with ramp rate requirements (down ramp and up ramp)

Lack of Real-Time and Operations Planning Time Frame[123] Coordination

The impact of the Lack of Real-Time and Operations Planning Timeframe Coordination risk is **high** because a lack of real-time coordination or coordination in the operations planning time frame between the large load and the TOP/BA can lead to thermal, voltage, or frequency stability impacts if the load changes demand without coordination or begins/ends a non-forced outage without coordination. The likelihood of a reliability impact from this risk is **high** because there are no requirements in the NERC Reliability Standards for real-time coordination between large loads and BAs/TOPs/RCs. The coordination that occurs between large loads and BAs/TOPs/RCs is often inadequate.

This risk cannot be adequately mitigated with existing registered entities. Interconnection requirements can contain requirements for real-time coordination and operations planning time frame coordination. However, because this risk is a high-likelihood, high-impact risk, a stronger mechanism to mitigate the risk is needed. For example, NERC standards, in addition to interconnection requirements, are used to mitigate the impact to the BPS from IBRs. Additionally, it is essential to establish requirements for operating protocols, communication protocols, and other operational and operations planning needs based on coordination with the BA/RC/TOP. These requirements might not be adequately covered in interconnection requirements.

To adequately mitigate the Lack of Real-Time and Operations Planning Time Frame Coordination risk, the following is needed from new type(s) of registered entity(ies):

- Perform real-time (and operations planning timeframe) coordination with the TOP, BA, and/or RC, as applicable
- Adhere to necessary operating protocols, communication protocols, etc.
- Comply with operating instructions from the TOP, BA, and/or RC, as applicable and ensure appropriate training for receiving those instructions

Lack of Proper Integration and Lack of Operational Readiness[124]

The impact of the Lack of Proper Integration and Lack of Operational Readiness risk is **high** because lack of effective integration and operational readiness can lead to other high impact risks discussed in this chapter, such as Lack of Real-time and Operations Time Frame Coordination, Frequency Stability, and Voltage Stability. Examples of operational readiness can include trip settings being different than were studied and demand behavior being different than was studied, as well as other characteristics. The likelihood of a reliability impact from this risk is **high** because even without large loads, lack of operational readiness for new major BPS additions (such as new generators) is already a likely concern. Adding more large loads to the grid significantly compounds this issue.

This risk cannot be adequately mitigated with existing registered entities. FAC-001 and FAC-002 provide a framework that helps mitigate this risk, but the large load might not provide the necessary data for performing

[123] "Near-term" operations planning time frame
[124] See NERC Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations

interconnection studies. While interconnection requirements are a powerful way to address issues, integration processes that incorporate feedback from operational registered entities are essential. Additionally, interconnection requirements can vary (by region, for example). Similar efforts are underway to increase the robustness of generation integration and validation processes. Because this risk is a high-impact risk, a stronger mechanism to mitigate the risk may be needed.

To adequately mitigate the Lack of Proper Integration and Lack of Operational Readiness risk, the following is needed from new type(s) of registered entity(ies):

- Provide TOs and/or other applicable entities with accurate information necessary for performing interconnection studies
- Coordinate with TOs and/or other applicable entities to establish a comprehensive commissioning process that ensures operational readiness
- Inform TOs and/or other applicable entities of any pertinent changes to the characteristics of the load after energization

Stability Risks

Frequency Stability (for the EI and Western Interconnection (WI))

The impact of risks to frequency stability in the EI or WI is **high** because "[t]he impact of an event that results in frequency-related instability…that affects a widespread area of the Interconnection" is an adverse reliability impact according to the NERC Glossary of Terms Used in NERC Reliability Standards.[125] The likelihood of frequency instability causing adverse impacts to BPS reliability in the EI or the WI is **low** because historical frequency response measures[126] demonstrate extreme resilience to even the largest load-loss events, coupled with a very large amount of on-line inertia historically at all times of the year.

This risk cannot be adequately mitigated with existing registered entities. Without accurate modeling data to assess the large load performance and resulting impact to the BPS, and disturbance ride-through requirements to address the impact, frequency stability may be at risk. Because this is a high-impact risk, a strong mechanism is needed to obtain these. Therefore, the existing registered entities are not able to adequately mitigate the risk. The accurate modeling data is needed to study frequency stability. The disturbance ride-through requirements are needed to help ensure frequency stability.

To adequately mitigate the Frequency Stability (for the EI and WI) risk, the following is needed from new type(s) of registered entity(ies):

- Ensure compliance with disturbance ride-through requirements
- Provide accurate load model data and ongoing model updates

Frequency Stability (for the Texas Interconnection (TI))[127]

The impact of risks to frequency stability in the TI is **high** because "[t]he impact of an event that results in frequency-related instability… that affects a widespread area of the Interconnection" is an adverse reliability impact according to the NERC Glossary of Terms Used in NERC Reliability Standards.[128] The likelihood of frequency instability causing adverse impacts to BPS reliability in the TI is **high** because a significant number of large loads are interconnecting in

[125] Available here: Glossary of Terms Used in NERC Reliability Standards
[126] See BAL-003-2 R1
[127] Note: The TI and QI Frequency Stability risks are separated from the EI and the WI because the TI and QI are smaller Interconnections than the EI and WI, leading to different likelihood/impact considerations for these Interconnections.
[128] Available here: Glossary of Terms Used in NERC Reliability Standards

areas that already have lower system strength. Following a fault, low voltages can therefore affect a wider geographic area and increase the risk of large loads tripping, causing frequency instability. The risk is further exacerbated during conditions with low load (when grid inertia is reduced) and low IBR output, which limits downward frequency response from these resources.

This risk cannot be adequately mitigated with existing registered entities. Without accurate modeling data to assess the large load performance and resulting impact to the BPS, and disturbance ride-through requirements to address the impact, frequency stability may be at risk. Because this is a high-impact risk, a strong mechanism is needed to obtain these. Therefore, the existing registered entities are not able to adequately mitigate the risk. The accurate modeling data is needed to study frequency stability. The disturbance ride-through requirements are needed to help ensure frequency stability.

To adequately mitigate the Frequency Stability (for the TI) risk, the following is needed from new type(s) of registered entity(ies):

- Ensure compliance with disturbance ride-through requirements
- Provide accurate load model data and ongoing model updates

Frequency Stability (for the Québec Interconnection (QI))[129]

The QI, although smaller than the EI, has unique characteristics that influence the nature of the Frequency Stability risk. The Québec system operates synchronously within its own boundaries and is interconnected with other North American Interconnections through HVdc links. This configuration limits the propagation of frequency-related events to or from other interconnections. The potential impact of a frequency instability event in the QI is **high**, as in the other interconnections, since "[t]he impact of an event that results in frequency-related instability… that affects a widespread area of the Interconnection" is an adverse reliability impact according to the NERC Glossary of Terms Used in NERC Reliability Standards.[130] However, the likelihood of such events occurring remains **low** due to several factors:

- **High Inertia:** Québec's generation fleet is predominantly hydroelectric, providing significant natural inertia and frequency regulation capabilities.
- **Historical Performance:** The Québec system has demonstrated strong resilience to major load-loss events, with effective and well-managed frequency response.
- **Regulation Margin:** Hydro-Québec normally has 1,000 MW of regulation margin (up or down) at any time. This allows for responding to large load losses or variations when they occur.
- **Emerging Load Growth:** While major industrial projects are under development (e.g., electrification of processes, data centers, hydrogen production), their integration is typically well planned and supported by rigorous grid-impact studies, which helps mitigate the risk of unexpected disturbances. While the largest load on the Hydro-Québec system is about 1,000 MW, it is an arc smelter, which likely poses fewer risks to the BPS than emerging large loads such as data centers. The largest data center load in Québec is roughly 30 MW in size; Québec is not expecting data center loads larger than this to energize in the coming years.

This risk can be mitigated with existing registered entities. The risk from emerging large loads in the QI to frequency stability is not significant.

[129] Note: The TI and QI frequency stability risks are separated from the EI and WI because the TI and QI are smaller Interconnections than the EI and WI, leading to different likelihood/impact considerations for these Interconnections.
[130] Available here: Glossary of Terms Used in NERC Reliability Standards

Voltage Stability

The impact of the Voltage Stability risk is **high** because over-voltages from large load demand changes or trips can lead to tripping of nearby generation or loads, creating a cascading effect. The likelihood of a reliability impact from this risk is **high** because it is well known that many large loads do not ride through common voltage disturbances.

This risk cannot be adequately mitigated with existing registered entities. Without accurate modeling data to assess the large load performance and resulting impact to the BPS, and disturbance ride-through requirements to address the impact, voltage stability may be at risk. Because this is a high-impact risk, a strong mechanism is needed to obtain these. Therefore, the existing registered entities are not able to adequately mitigate the risk. The accurate modeling data is needed to study voltage stability. The disturbance ride-through requirements are needed to help ensure voltage stability.

To adequately mitigate the Voltage Stability risk, the following is needed from new type(s) of registered entity(ies):

- Ensure compliance with disturbance ride-through requirements
- Provide accurate load model data and ongoing model updates

Angular Stability

"The portion of the BPS affected by a particular loss of synchronism event can vary greatly, and consequences range from the outage of a single plant to the islanding of large sections of an interconnection."[131] Therefore, the impact from the Angular Stability risk is categorized as **moderate** to reflect both scenarios. The sudden disconnection of large load(s) can lead to angular stability impacts. This effect becomes more significant for loads that are larger in size. Impact is higher in areas with heavy co-location of large loads and large generators. The likelihood of a reliability impact from this risk is **moderate**. An SLG fault can cause voltage-sensitive large loads such as data centers to disconnect, leading to potential loss of synchronism of nearby generation.[132] This is notable because, without the disconnection of the large load(s), SLG faults would not usually impact nearby generation. The likelihood of angular stability-related reliability impacts due to large load disconnection is higher in areas with heavy co-location of voltage-sensitive large loads and generators.

This risk cannot be adequately mitigated with existing registered entities. Without accurate, detailed modeling data to assess the large load performance and resulting impact to the BPS, and disturbance ride-through requirements to address the impact, angular stability may be at risk. Interconnection requirements may not be a strong enough mechanism to provide these mitigations. Because this risk is a moderate-likelihood, moderate-impact risk, a stronger mechanism to mitigate the risk is needed. Therefore, the existing registered entities are not able to adequately mitigate the risk. Additionally, due to angular stability posing system-wide risks, the requirements for dynamic modeling and studies should be established on a system-wide basis.

To adequately mitigate the Angular Stability risk, the following is needed from new type(s) of registered entity(ies):

- Ensure compliance with disturbance ride-through requirements
- Provide accurate load model data and ongoing model updates

[131] White Paper Characteristics and Risks of Emerging Large Loads

[132] Note: The amount of voltage sensitivity, re-connection behavior, and system topology affect the likelihood of this risk.

Oscillations

The likelihood of a large impact (e.g., cascading or large number of generators tripping) due to large load oscillation(s) is probably low to moderate. However, the potential impact of such an event is extremely high. The likelihood of a small impact (single generator trip) due to a large load oscillation(s) is likely high because data centers are known to have oscillatory behavior and a significant portion of the overall system load in the future will be composed of large loads such as data centers. Additionally, the average size of these large loads in the future will also be very large, leading to a higher chance of impacts from data center oscillations. Because of these high-impact scenarios, the impact for the Oscillations Risk is categorized as **high.** Because the likelihood of the impact depends on the severity of the impact, the likelihood of a reliability impact from this risk is categorized as **moderate** to reflect both of the types of scenarios.

This risk cannot be adequately mitigated with existing registered entities. Existing registered entities in many areas actively monitor for oscillations in real time. It will likely be necessary for the large loads to collaborate with the registered entity to mitigate oscillations, but this collaboration can likely be achieved without Reliability Standards because the TOP has the ability to deny the large load permission to operate if it is causing oscillation issues. However, the reliability of the BPS cannot rely on detecting oscillations in real time and delayed operator response to preserve the reliability of the grid. Oscillations need to be mitigated before they occur so that they do not occur in real time. Detecting the oscillation risks before they occur is more challenging because of the lack of accurate large load model data and the fact that sub-synchronous resonance studies are very dependent on the quality of the large load models. Additionally, this risk needs to be considered on an interconnection-wide basis, not for single registered entities, as compounding frequency content injection across an interconnection can lead to severe consequences. Therefore, existing registered entities cannot adequately mitigate this risk. Large loads need to provide accurate modeling data, and Reliability Standard requirements on large loads are needed to enforce the provision of accurate load modeling data.

To adequately mitigate the Oscillations risk, the following is needed from new type(s) of registered entity(ies):

- Provide accurate load model data and ongoing model updates
- Ensure compliance with performance requirements (such as requirements from the TO, TP, or PC) to minimize and mitigate unintentional local area or interconnection-wide power oscillation interaction during normal and post-event conditions

Lack of Visibility of Disturbance Ride-Through Characteristics

The impact of the Lack of Visibility of Disturbance Ride-Through Characteristics risk is **high** because lack of disturbance ride-through can lead to frequency stability risks, voltage stability risks, or other risks. The likelihood of a reliability impact from this risk is **high** because it is well known that grid planners and operators often do not know the disturbance ride-through characteristics of large loads.

This risk can be mitigated with existing registered entities. Accurate model data for large loads is needed so that frequency stability can be accurately studied. Without accurate models, frequency stability may be at risk. This risk can be addressed by TOs if they have interconnection requirements that include model validation, model verification, commissioning testing, and other key requirements to ensure that the model data regarding disturbance ride-through characteristics is accurate.

Power Quality Risks

Voltage Fluctuations

The impact of the Voltage Fluctuations risk is **low** because voltage fluctuations (i.e., flicker) are known to not be a major issue for BPS reliability. The likelihood of a reliability impact from this risk is **low** because the likelihood of voltage fluctuations having an impact on BPS reliability is known to be low.

This risk can be mitigated with existing registered entities. This is not a significant impact to BPS reliability.

Harmonics

The impact of the harmonics risk is **low** because harmonics, even when above recommended limits, seldom cause generator damage directly impacting BPS reliability and seldom cause forced outages in BPS equipment. Additionally, the impacts from harmonics are generally localized. If it is found that harmonics, such as supraharmonics, caused by data centers cause more significant impacts to the BPS, this impact level could change. The likelihood of a reliability impact from this risk is **low** because mature and commonly used design practices and solutions exist for reducing the harmonics from electronic loads to below recommended limits.

This risk can be mitigated with existing registered entities. Interconnection requirements could address this issue. It is not a significant impact to BPS reliability, so NERC-enforceable requirements are not necessary. This can be adequately addressed with existing registered entities' policies.

Security Risks

Cyber Security of Large Load

Bad actors could induce many other high-impact risks through adversarial control which could bypass controls that mitigate other risks. If this occurred with multiple large loads, the impact from the cyber security of large load risk could be high. If this occurred with a single large load, the impact would likely be moderate. To reflect both scenarios, this Cyber Security of Large Load risk is categorized as **high** impact. The penetration of large loads on the BPS is growing, especially computational loads. Data sharing and collaboration are increasing, which increases the cyber security attack surface. Additionally, the adversaries are growing more capable. The likelihood of a high impact from this risk is low. The likelihood of a low impact from this risk is high. To reflect both scenarios, this risk is categorized as **moderate** likelihood.

This risk cannot be adequately mitigated with existing registered entities. Existing registered entities do not have adequate visibility of the large load asset owner's security protocols and practices to be able to appropriately provide requirements to mitigate the cyber security risks. Additionally, data is needed from the large load entities regarding their cyber security fabrics.

To adequately mitigate the Cyber Security of Large Load risk, the following is needed from new type(s) of registered entity(ies):

- Provide utility with site vulnerability/risk assessment and mitigate issues discovered in this assessment
- Notify utility (in close to real time) of security breaches

Cyber Security of Communications Between the Large Load and the Utilities

The impact of the Cyber Security of Communications Between the Large Load and the Utilities risk is **low** because data centers already have security practices. Existing registered entities already have NERC CIP standards in place as well. Data centers usually have tiered cyber security protection practices. Communication between the large loads and the DP, TO, TOP, BA, RC, or PC is usually going to be secure because data centers already have security practices, although the security practices may not be consistent across the industry. The tiered cyber security protection practices need to be extended out to the communication between the large loads and the utilities, and the cyber security practices for this communication should be designed in coordination with the utilities. The likelihood of a reliability impact from this risk is **low**. Some communication could be more impactful to BPS reliability, such as communication for demand response; however, this communication will likely involve more advanced security practices.

This risk can be mitigated with existing registered entities. This is a low-likelihood, low-impact risk. If needed, NERC standards can be written or modified, or guidance written, to address the cyber security risks posed by the large load to the BPS. If these standards were enforceable to existing registered entities (or the guidance addressed to existing registered entities), they could use their interconnection requirements and other processes to help ensure that the requirements in the standards or the recommendations in the guidance are followed.

Physical Security

The impact from the Physical Security risk is **moderate or high** because a physical security incident could result in some of the other BPS risks discussed in this chapter. The likelihood of a reliability impact from this risk is **moderate** because substations serving these loads may be easily accessible. Additionally, these incidents could be random targets.

This risk cannot be adequately mitigated with existing registered entities. While TO interconnection requirements could be used to help achieve the needed security protocols, lack of standardization across the BPS areas would lead to inadequate reliability. Although NERC standards applicable to the TOs could address this and the TOs could put these requirements in their interconnection requirements, the TOs may not own the substations and do not own the data centers. Physical security is not one-size-fits-all; design basis threats are used to design physical security systems and protocols. The responsibility for physical security will depend on the location. For example, the data center will have to be responsible for the security inside the data center and the TO might be responsible for the security outside of the data center (e.g., the substation).

To adequately mitigate the Physical Security risk, the following is needed from new type(s) of registered entity(ies):

- Provide utility with site vulnerability/risk assessment and mitigate issues discovered in this assessment
- Notify utility (in close to real time) of security breaches.

Load-Shedding & System Restoration Risks

Manual Load Shed Obligations

The impact of the Manual Load Shed Obligations risk is **high** because, for a situation in which a TOP or DP needs to shed a portion of a large load but the particular load is not able to be segmented, other issues, such as voltage instability, could be caused by the shedding of the entirety of the load. The likelihood of a reliability impact from this risk is **moderate** because the likelihood of needing to shed load to maintain reliability has increased due to significant generation and transmission expansion deficiencies, and a more constrained grid.

This risk can be mitigated with existing registered entities, although a more optimal solution could be reached if large loads were a registered entity.

Automatic UFLS Programs

The impact of the Automatic UFLS Programs risk is **high** because "UFLS programs are the last line of defense for BPS reliability."[133] If there is not enough load on the UFLS program, or the UFLS program does not function as expected to mitigate the frequency decline, then system-wide instability can occur, leading to cascading generator outages. The likelihood of a reliability impact from this risk is **low** because the chances of needing to use UFLS are low; historically, use of UFLS has been rare. With the current penetration, the likelihood of not having enough load on UFLS programs is low. However, with the load expected to be connected in the coming years, more load will need to be added to the UFLS programs; if load is not added, the risk may be higher. But again, the likelihood of needing to use UFLS is historically low.

[133] White Paper Characteristics and Risks of Emerging Large Loads

This risk can be mitigated with existing registered entities. Because shedding an entire large load simultaneously may cause stability concerns, there is a need to segment some large loads if they are on the UFLS program. This segmentation likely needs to be a requirement in the TO's interconnection requirements. Because this segmenting may lead to needing to have UFLS relays within the load, there may be situations where it is necessary for the large load to own UFLS relays and other related equipment. A non-registered entity owning UFLS equipment might be a risk. Therefore, the load entity might need to be registered as a UFLS-Only DP. However, none of this indicates a need to have a new type of registered entity. Additionally, there is a concern of having an inadequate amount of load on the UFLS program due to a significant amount of load being added to the system after the last PRC-006 UFLS design assessment. However, PCs can partially address this concern by reviewing their UFLS programs when large load interconnection requests are submitted to the TOs.

System Restoration

The impact of the System Restoration risk is **low** because large loads will not typically be energized early in the system restoration process.[134] The likelihood of a reliability impact from this risk is **low** because the likelihood of being in a restoration scenario is low.

This risk can be mitigated with existing registered entities. This is a low-likelihood, low-impact risk.

[134] Note: If the load was energized early in the restoration process, then this risk may be higher impact due to some large loads being known to rapidly change demand

Chapter 9: Conclusion

Addressing the Challenges and Shaping the Future

It is imperative that NERC and industry stakeholders prioritize the reliability of the grid to ensure that large loads can be connected in a reliable manner. The LLWG has identified critical reliability gaps across the lifecycle of large load integration from interconnection to long-term planning, operations, modeling, and security. Identifying and addressing these gaps will help ensure that the North American grid is ready to safely, reliably, and securely integrate these advancing technologies.

It is imperative that NERC and industry stakeholders prioritize the reliability of the grid to ensure that Large Loads can be connected in a reliable manner

This white paper identified the following critical items:

1. **Opportunities to enhance NERC Reliability Standards to better accommodate large loads**
2. **Gaps in existing standards and practices concerning large loads**
3. **The lack of a registered function attributable to large loads or BPS users specifically or to LSEs**

In addition to opportunities for reforming the interconnection process at the federal or state government level, the identified gaps and opportunities could also be addressed by enhancing Reliability Standards for existing registered entities as well as updating registry criteria and Reliability Standards for large loads and/or LSEs. Updates to registration criteria are needed so that Reliability Standards can be applicable to large loads and/or LSEs. These recommended updates would support a grid that can safely, reliably, and securely accommodate large load users of the BPS.

This paper serves as a foundational step in updating industry practices to address the challenges of integrating large loads into the evolving electric grid. Alongside the LLTF *Characteristics and Risks of Emerging Large Loads* white paper,[135] it performs Step 1 of the RSTC Standard Authorization Request (SAR) Process.[136] The RSTC or others may[137] consider developing SARs or other mitigating measures to mitigate the reliability gaps discussed in this paper.

Unveiling the Critical Gaps: A Path to Reliability

The following provides a summary of many notable gaps identified in this white paper. Additional details and gaps identified can be found in the applicable sections of this paper.

Interconnection Processes and Requirements Gaps

Current interconnection processes for large loads lack standardization in comprehensive study components and performance requirements to assess reliability impacts to the grid. In many cases, large load developers or LSEs do not provide accurate modeling and operational characteristics data. As a result, TOs and TPs often study these loads with limited visibility into their performance characteristics. Additionally, NERC Reliability Standards do not require TOs to establish specific interconnection requirements reflecting the needs of their respective BAs and RCs, leading to incomplete system impact assessments. The difficulty of studying large load performance is further compounded by the accelerated development timelines typical of large load projects, which frequently outpace necessary transmission upgrades, resource construction, or operational readiness.

Current interconnection processes for large loads lacks standardization in comprehensive study and performance requirements to assess reliability impacts

[135] Available here: White Paper Characteristics and Risks of Emerging Large Loads
[136] Available here: RSTC SAR Development Process clean Sept 20 2023.pdf
[137] *Ibid. See also*, the NERC Rules of Procedure regarding submittal of SARs.

Unlike generator interconnections, large load interconnections typically lack requirements for post-energization model validation, performance validation, or other information gathering. This results in a gap to assess real-time performance compared to planning and operational planning assumptions. Greater emphasis is needed in detailed modeling data and performance validation process to ensure that the large loads are adhering to the design and performance requirements. Additionally, there is a lack of collaboration and coordination between large load entities, utilities, and other entities. For example, there may be gaps in the coordination between grid operators/planners and the large load entities regarding important large load design decisions, such as those related to the facility's transfer to backup power supply and the return to utility during/after voltage disturbances.

Planning and Resource Adequacy Gaps

Many traditional long- and short-term planning processes may not account for the scale, uncertainty, and dynamic behavior of emerging large loads

Many traditional long- and short-term planning processes may not account for the scale, uncertainty, and dynamic behavior of emerging large loads. Unlike conventional load additions, many of these facilities energize incrementally over months or years, often deviating from initial development timelines and forecasted demand profiles. Current load forecasting methods lack well-established mechanisms to incorporate these long-term load ramping profiles, the impact of behind-the-meter generation or storage, and the potential for participation in demand-response or price-responsive programs. Although not all large load interconnection requests will materialize, there is no uniform guidance across the industry on when and how large loads should be integrated into planning studies. The absence of standardized input assumptions for these loads significantly impacts the accuracy of resource adequacy assessments. This gap increases the risk of misalignment between actual system needs and infrastructure procurement, potentially leading to under-investment in generation and transmission or investing in transmission infrastructure in the wrong locations. There is an opportunity for stronger coordination among planning entities and other entities and for improved accuracy. Additionally, a potential gap in Reliability Standard FAC-002 is that there is no requirement for resource adequacy to be checked before integrating a new large load onto the system or before the peak demand of an existing large load is increased.

Balancing and Operational Gaps

Large loads may exhibit sudden changes in power consumption under normal conditions or reduce demand during voltage or frequency excursions, leading to an imbalance between generation and load. Computational facilities are loads driven by power electronics and can be highly responsive to grid conditions and other signals. In fact, it is arguable that computational large loads essentially operate as controllable BES elements. As most large load users of the BPS are not NERC registered entities, they are not directly subject to coordination requirements with BAs (such as the requirements in Reliability Standard TOP-001). Furthermore, LSEs were also removed from the NERC registry criteria based on specific facts and circumstances approximately 10 years ago, so they are not subject to the coordination requirements with BAs. Without modifying the NERC registry criteria and Reliability Standards in order to have enforceable coordination requirements and other requirements for large loads, large load real-time operating behavior can result in ACE volatility and exhaustion of generation resources used for frequency regulation. Gaps may exist in the BAL-001, BAL-002, and BAL-003 Reliability Standards and associated processes as they do not fully address the risks related to balancing posed by large loads. For example, in the process associated with BAL-003, all BAs submit their largest credible generation contingencies, but this standard does not have a similar process for load loss contingencies. This generator loss information is used to determine the amount of frequency response required for the interconnection and for individual BAs. Operators often lack telemetry or observability into large load facilities,

As LSEs and most large load users of the BPS are not NERC registered entities, they are not directly subject to coordination requirements with BAs

resulting in a lack of situational awareness that can impact real-time decision-making. Additionally, gaps exist in requiring large loads to provide RCs/BAs/TOPs with the data necessary to perform reliable operations. Furthermore, as highly controllable and impactful facilities, gaps exist in that large loads are not obligated to establish interpersonal communication protocols with system operators nor be trained in critical reliability related tasks. Additionally, gaps may exist in the engineering practices related to checking operational readiness prior to energization of large loads. Examples of these practices include integrating new loads into modeling tools and energy management systems, and operational agreements covering communication for normal and emergency operations. There may also be a gap in IRO-017 and related practices in that this standard does not explicitly consider outages of large loads. Overall, many of the NERC standards related to planning, operations, and operations planning do not consider the impacts of large-scale ramping, disconnection, and reconnection events.

Disturbance Ride-Through, Stability, and Power Quality Gaps

Utilities do not always know the voltage and frequency disturbance ride-through characteristics of large loads, making it difficult to assess stability concerns. No existing NERC Reliability Standards provide requirements for voltage or frequency disturbance ride-through of large loads, and the lack of data on large load performance makes it difficult to study these loads. There is also a lack of coordination between existing registered entities and large loads on when a load should return to pre-disturbance demand levels after a voltage/frequency disturbance. Regarding existing registered entities, gaps exist related to the following:

Utilities do not always know the voltage and frequency disturbance ride-through characteristics of large loads, making it difficult to assess stability concerns

- Load models used and scenarios considered in transient stability studies
- Load modeling practices related to frequency and voltage stability studies
- Scenarios used for frequency stability studies.
- The impacts of large loads on UFLS and UVLS programs.

IEEE standards, such as IEEE 519, provide requirements for limiting harmonics and this standard can be applied to large loads. The limits, applicable to both voltage and current, are common to all interconnections without further coordination among them. However, the lack of coordination among different large load interconnections may create situations where individual projects are compliant with limits at their connection point but create non-compliance at other nodes in the system.[138] Furthermore, there are gaps in determining interharmonic limits.

There are also gaps in the modeling and practices related to converter-driven stability, resonance stability, and allowable limits for forced oscillations.

Security, Resilience, and Event Analysis Gaps

Large loads often deploy extensive cyber-physical systems, including private IoT infrastructure, that introduce opportunities for potential attacks by threat actors that are not addressed by current NERC CIP Standards. Because most large load facilities are not registered entities, they are not obligated to follow NERC CIP or PER Standards even though their size and connectivity may pose reliability risks. Additionally, with most not being NERC registered entities, these loads are not subject to post-event analysis reporting requirements. Large loads are also not subject to disturbance monitoring requirements in the NERC Reliability Standards; this may also be gap.

[138] In comparison, other jurisdictions, such as most European transmission system operators, provide individual harmonic emission limits to each customer enforced as part of the compliance process.

Large loads often deploy extensive cyber-physical systems, including private IoT infrastructure, that introduce opportunities for potential attacks by threat actors that are not addressed by current NERC CIP Standards

Modeling Gaps

Existing phasor domain load models do not adequately reflect the characteristics of large power electronic loads.[139] Data center UPS systems, hydrogen electrolyzer power supplies, and AI training facilities exhibit dynamic and nonlinear responses during system events. In many cases, even when a phasor domain or EMT model is developed, engineers lack the necessary parameter inputs or operational data to validate the models. EMT models may be required in weak grid conditions, but there is limited guidance or standardization on when or how to apply them to load studies. Additionally, model quality testing procedures are not used for large loads, increasing the risk of invalid or unstable models being used in planning or operational assessments.

In many cases, even when a phasor domain or electromagnetic transient (EMT) model is developed, engineers lack the necessary parameter inputs or operational data to validate the models

Risk Categorization and Mitigations

To determine the proper mitigation to address each of the gaps discussed in this paper, the relevant risk was categorized by likelihood and impact. Existing NERC registered entities cannot address many of the risks to the BPS from emerging large loads. Requirements are needed for additional entities (such as large loads, LSEs, or similar entities) to adequately address the risks, especially due to the severity of the risk.

Critical Reliability Recommendations

To ensure that large loads can be reliably integrated into the BPS, the LLWG recommends updating Reliability Standards and NERC registry criteria to reflect the electric grid of today and the future. Registry criteria for large loads and LSEs should be considered so that NERC Reliability Standards can be directly applicable. Reliability Standards modifications should be made for existing registered entities and large load entities. As discussed in this paper, many gaps exist in areas such as interconnection requirements, operations and balancing standards, and load modeling. Without updates to registry criteria, large loads and LSEs are not subject to Reliability Standards.

The LLWG recommends a combination of Reliability Standards updates, registry criteria revisions, educational material/guidance, and coordination with relevant stakeholders to help address the gaps identified in this white paper. The solution to address the gap may not always be to update the specific NERC standard, requirement, or process that has the gap. To tailor risk mitigation, the LLWG recommends a holistic and nuanced approach for the design of mitigation measures to ensure that the grid is ready to safely and reliably integrate emerging large loads. This approach needs to consider the likelihood of impact to the BPS from the risk and the severity of the impact. The NERC *Framework to Address Known and Emerging Reliability and Security Risks*[140] document provides direction regarding how the risks from emerging large loads should be addressed. The LLWG recommends that this document be utilized to determine appropriate risk mitigations. Applicable stakeholders should consider the gaps discussed in this paper and implement risk mitigations to address the risks posed by emerging large loads.

The following recommendations are offered as guidance to ensure the reliability and security of the BPS.[141]

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[139] The EV charger model developed by the Electric Power Research Institute does allow for modeling some aspects of large power electronic loads. Additionally, the Power Electronic Reconnecting and Ceasing (PERC1) model allows for modeling some aspects of large power electronic loads.

[140] Available here: [Framework to Address Known and Emerging Reliability and Security Risks]

[141] See Chapter 8 for an analysis of the risk categorization and mitigations that led to the Recommendations 1–3.

Recommendation 1: Because there are multiple high-impact risks to the BPS from large loads that NERC registered entities cannot adequately address, the LLWG recommends that NERC pursue registration of a type of entity (or types of entities) that is able to perform the following regarding large loads:[142]

- Provide accurate short-term demand forecast data
- Provide sufficient data for applicable entities (e.g., RC, TOP, and BA) for the development of short-term demand forecasts and operating plans
- Provide accurate load model data and ongoing model updates
- Inform the TO and/or other applicable entities of any pertinent changes to the characteristics of the load before and after energization
- Perform real-time (and operations planning time frame) coordination with the TOP, BA, and/or RC, as applicable
- Comply with operating instructions from the TOP, BA, and/or RC, as applicable, and ensure appropriate training for receiving those instructions
- Ensure compliance with disturbance ride-through requirements
- Ensure compliance with ramp rate requirements (down ramp and up ramp)
- Provide accurate information (as accurate as possible and as early as possible) regarding large load dynamic model to support interconnection and transmission planning studies
- Provide TOs and/or other applicable entities with accurate information necessary for performing interconnection studies
- Coordinate with TOs and/or other applicable entities to establish a comprehensive commissioning process that ensures operational readiness
- Adhere to necessary operating protocols, communication protocols, etc.
- Ensure compliance with performance requirements (such as requirements from the TO, TP, or PC) to minimize and mitigate unintentional local area or interconnection-wide power oscillation interaction during normal and post-event conditions
- Provide utility with site vulnerability/risk assessment and mitigate issues discovered in this assessment
- Notify utility (in close to real time) of security breaches

Recommendation 2: The LLWG and other groups should propose SARs, including a SAR for adding a definition of "large load" to the NERC *Glossary of Terms*,[143] to address the following unmitigated risks to the BPS related to emerging large loads:[144]

- **Long-Term Planning Risks**
  - Resource Adequacy
  - Transmission Adequacy

[142] The findings of the NERC Level 2 Alert: Large Load Interconnection, Study, Commissioning, and Operations, distributed on September 9, 2025, will likely help provide more information regarding the need to pursue registration of an entity type (or types of entities).
[143] Available here: Glossary of Terms Used in NERC Reliability Standards
[144] NERC requirements written for large loads may need to be coordinated with NERC requirements for generation, such as in the case of a generator(s) and a large load facility being co-located with a common point of interconnection.

- Long-Term[145] Demand Forecasting

- **Operations/Balancing Risks**
  - Short-Term[146] Demand Forecasting
  - Balancing and Reserves
  - Lack of Real-Time and Operations Planning Time Frame[147] Coordination
  - Lack of Proper Integration and Lack of Operational Readiness[148]
- **Stability Risks**
  - Frequency Stability
  - Voltage Stability
  - Angular Stability
  - Oscillations
  - Lack of Visibility of Disturbance Ride-Through Characteristics
- **Security Risks**
  - Cyber Security of Large Load
  - Physical Security
- **Load-Shedding Risks**
  - Manual Load Shed Obligations
  - Automatic UFLS Programs

Recommendation 3: The LLWG should identify potential mitigations to risks posed by emerging large loads through improvements to existing planning and operations processes and interconnection procedures for large loads as planned for the LLWG's work item titled *Reliability Guideline: Risk Mitigation for Emerging Large Loads*. This guideline should address the risks discussed in Recommendation 2 of this white paper as well as the following risks:

- **Power Quality Risks**
  - Voltage Fluctuations
  - Harmonics
- **Security Risks**
  - Cyber Security of Communications Between the Large Load and the Utilities

Recommendation 4: Registered entities should coordinate and collaborate with large load entities and update their practices to address the gaps discussed in this paper. The upcoming LLWG reliability guideline will help provide guidance on addressing the BPS risks posed by emerging large loads.

Recommendation 5: TOs should coordinate with TPs, TOPs, PCS, BAs, and RCs as applicable to update their interconnection requirements in a timely manner to address the gaps discussed in this paper, including coordination

145 i.e., later than operational
146 (operational)
147 "Near-term" operations planning time frame
148 See [NERC Industry Recommendation: Large Load Interconnection, Study, Commissioning, and Operations]

and collaboration with large load entities. Additionally, PCs and TPs should update their interconnection study processes to address the gaps discussed in this paper.

Recommendation 6: The NERC Load Modeling Working Group should work to address the gaps in load modeling practices and scenarios to study as identified in this paper.

Recommendation 7: The NERC Security Working Group should further assess security gaps related to emerging large loads and propose mitigations for these gaps (including potential SARs).

Recommendation 8: The NERC System Protection and Control Working Group should further investigate any gaps related to system protection and control systems and propose mitigations for these gaps (including potential SARs).[149]

Recommendation 9: Federal and/or state regulators, as applicable, should consider the gaps identified in this paper and coordinate with utilities to assess whether incorporating additional interconnection requirements and/or studies are appropriate to reliably support integration of large loads. The LLWG supports federal and state efforts to enhance consistency in interconnection processes where possible. As of Fall 2025, the Federal Energy Regulatory Commission (FERC) is examining this question in Docket No. RM26-4.

Recommendation 10: State regulators should work with regulated utilities to review how new loads and planned additional generation impact existing planning and risk assessment frameworks. States may need to adjust their resource adequacy criteria and/or work with their utilities on energy infrastructure expansion.

Recommendation 11: To ensure that adequate resources are added or in place to meet the needs of the BPS, policymakers should review interactions between interconnection requirements, existing state regulations and planning processes, and regional grid operator requirements. Additionally, policymakers should work to better understand the full impact of large load integration in their jurisdiction, and review requirements for large load customers to provide operational data and information to TOs, TOPs, TPs, and other entities.

[149] This white paper discusses gaps related to system protection in Chapter 2. However, additional gaps may exist, and further work is needed to assess the extent of the gaps and provided recommendations to address the gaps.

Appendix A: Phasor/Time Domain Simulation Tools, Modeling Terminology, and Applications

The use cases of various simulation tools are provided in Figure A.1.

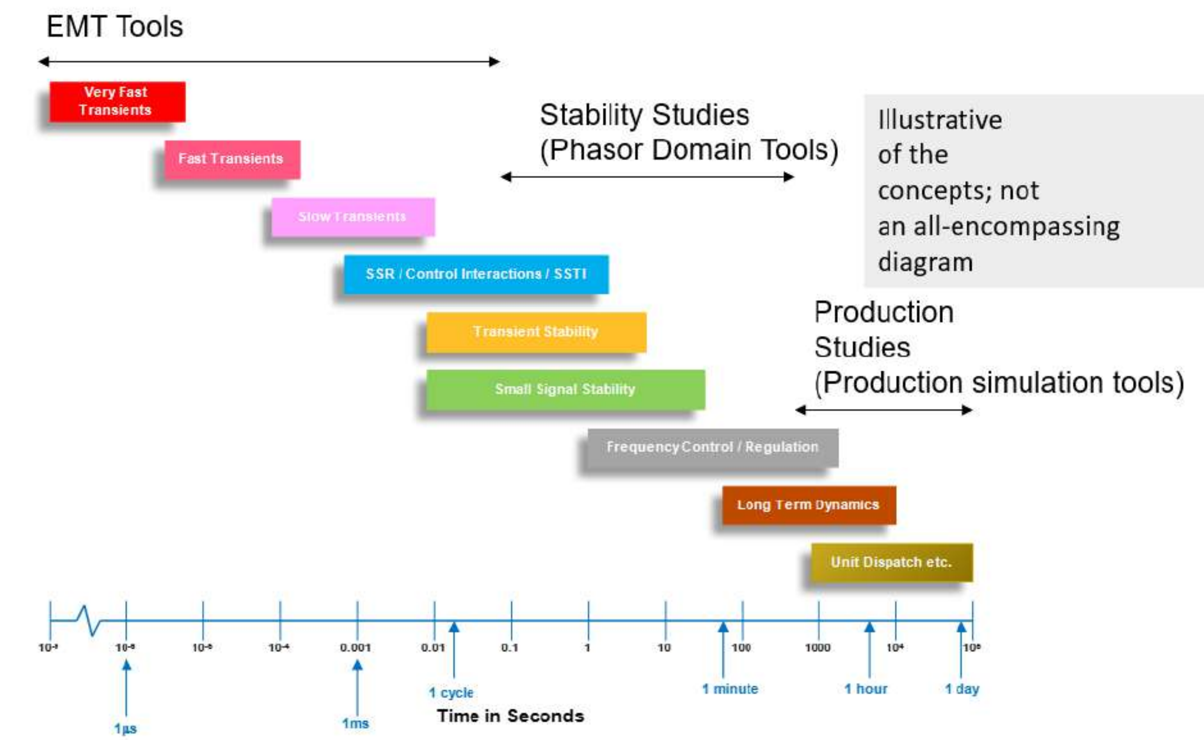

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Figure A.1: Simulation Tool Applicability Based on Dynamics Being Simulated

Terminology related to models and modeling platforms is provided below:

1. **Phasor Simulation Tools and Models:**
   a. **Purpose**: Used to study reliability risks related to slower local and inter-area oscillatory dynamics, angular and voltage stability, and unacceptable voltage and frequency excursions resulting from unexpected loss of large load during grid disturbances and unexpected load ramps.
      - **Characteristics**: These tools use simplified models to study bulk system reliability impacts, which are generally slower frequency events. Models in positive sequence platforms need to be reasonably accurate without being computationally burdensome. For example, the composite load model, with about 130 parameters, already slows down simulations for large interconnections. New large load models should not significantly add to the existing computational burden while still accurately modeling the phenomena of interest.
2. **EMT Simulation Tools and Models:**
   a. **Purpose**: Used to study reliability risks related to faster dynamics, such as subsynchronous resonances and interactions, ferroresonances, switching transients, and harmonic stability assessments.
   b. **Characteristics**: EMT models are significantly more detailed than phasor models, including faster controls and the switching of power electronic devices for certain evaluations. EMT studies typically involve detailed models of the local system connected to an external system. Due to their high level of detail,

EMT models and tools are generally not used for bulk system analysis, although some utilities maintain EMT models for their entire footprints. Most utilities use EMT studies for screened parts of the system where the reliability challenges can only be captured by modeling the faster dynamics systems, (e.g., phase-locked loop instability for weak grids, subsynchronous interactions).

3. **Generic and Original Equipment Manufacturer (OEM) Models:**

   a. **Generic Models**: Representations of power system equipment based on the basic physics of the device being modeled, covering key stability and control features common to most manufacturers. These models do not include proprietary control methods and are well documented. They are useful for long-term transmission planning studies where equipment manufacturers are not yet decided. OEMs may parameterize these models to reflect their device's dynamic performance and submit them to the relevant TP.

   b. **OEM Models**: Developed by OEMs to reflect the controls and dynamics of their own equipment, including proprietary controls. These models are often black-boxed to protect intellectual property and are submitted as user-defined library-linked models, with modeling details hidden from the TP. OEM models are used when generic models cannot sufficiently replicate the behavior of the equipment. OEM models can be in either the phasor domain or EMT.

Appendix B: NERC Standards and Applicable Sections

Table B.1 provides a list of the NERC Reliability Standards that are discussed in this paper and the paper sections (excluding the **Conclusion** chapter) in which these standards are discussed:

Table B.1: NERC Reliability Standard Discussions

Relevant Paper Chapter	Standard[150]
Chapter 2: Interconnection Processes and Requirements	FAC-001
	FAC-002
Chapter 3: Planning and Resource Adequacy	BAL-502-RF
	FAC-002
	MOD-031
	MOD-032
	TPL-001
Chapter 4: Balancing and Operations	BAL-001
	BAL-002
	BAL-003
	BAL-007
	COM-001
	COM-002
	FAC-002
	FAC-011
	IRO-008
	IRO-010
	IRO-017
	PER-005
	TOP-001
	TOP-002
	TOP-003
	TPL-001
Chapter 5: Disturbance Ride-Through, Stability, and Power Quality	BAL-003
	FAC-001
	FAC-002
	MOD-032
	PRC-006
	PRC-010
	PRC-019
	PRC-024
	PRC-028
	PRC-029
	TPL-001
Chapter 6: Security, Resilience, and Event Analysis	CIP-004

[150] The NERC Reliability Standards can be found here: Reliability Standards

Table B.1: NERC Reliability Standard Discussions	
Relevant Paper Chapter	**Standard[150]**
	CIP-006
	CIP-007
	CIP-008
	CIP-014
	EOP-004
	PER-003
	PER-005
	PER-006
	PRC-002
	PRC-028
Chapter 7: Modeling of Large Loads	MOD-026
	MOD-027
	MOD-033
Chapter 8: Risk Categorization and Mitigations	FAC-001
	FAC-002
	PRC-006

Appendix C: Acknowledgements

NERC gratefully acknowledges the contributions and assistance of the following industry experts in the preparation of this white paper.

Table C.1: Contributors

Name	Company
Adam Kliber	IESO
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Name	**Company**
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Tyler Springer	AEP
Valerie Carter-Ridley	NERC

CONFIDENTIAL: SUBJECT TO THE PROTECTIVE ORDER ISSUED IN CASE NO. U-22058

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-4.1	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 1. Refer to discovery response CEOMEIBCIEIDE-1.28ai, where Witness Benyard states:
"These studies included steady-state thermal and voltage analysis, short circuit and stability analysis." In discovery response CEOMEIBCIEIDE-1.28a, Witness Benyard states that these studies "were conducted at the transmission level by ITC." BEGIN CONFIDENTIAL [redacted]
END CONFIDENTIAL

Please explain the discrepancies between these two statements regarding short circuit and stability analysis.

Answer: The response to 1.28a should have been written to state that these studies are being evaluated on an ongoing basis. Similarly, with respect 1.28ai, these studies are being conducted by ITC or, with respect to the short circuit and stability analysis, may be conducted in the future as DTE and ITC continue to conduct studies to develop operating requirements for grid protection.

Attachment: *None*

Co-respondent: Legal

LAURA S. SHERMAN, Ph.D.

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PROFESSIONAL EXPERIENCE:

April 2019 – present **Michigan EIBC/IEI**, Lansing, MI **President**

- Organize and lead a staff of five employees, contractors, and student interns.
- Work with and inform each organization's Board of key decisions, upcoming events, long-term strategy, etc.
- Fundraise and coordinate both organization's annual budgets.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.
- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.

Oct. 2017-March 2019 **Michigan EIBC/IEI**, Lansing, MI **VP for Policy Development**

- Develop regulatory and legislative policy positions to support advanced energy businesses.
- Coordinate regulatory interventions and engagement in regulatory stakeholder processes among member companies.
- Engage with the Michigan Public Service Commission and Michigan legislature on behalf of member companies.
- Support policy initiatives focused on wind energy, solar energy, electric vehicles, storage, taxation, and corporate purchasing of renewable energy.
- Represent Michigan EIBC in the media, at the legislature, with regulators, and with the state administration in collaboration with a broad coalition.
- Conduct event planning including for annual conferences, networking events, tours, and legislative networking opportunities.

Feb. 2017-March 2019 **5 Lakes Energy**, Lansing, MI **Senior Consultant**

- Research, analysis, communication, and advocacy surrounding complex energy issues.
- Lead wind and solar siting project to address opposition to deployment in coordination with philanthropy, industry, and stakeholders across nine Midwest states.
- Focus areas include renewable energy development, community engagement, stakeholder coordination, business sustainability, and electric vehicles.
- Support newsletter, website, and social media communications.

April 2015-Dec. 2016 **U.S. Senate**, Washington, DC **Legislative Assistant/Policy Advisor**

- Policy advisor to Senator Michael Bennet (D-CO) on agriculture, energy, environment, land, and natural resource issues.
- Legislative topics included: farming and ranching, public land conservation and management, water policy, energy development, renewable energy including energy tax incentives and transmission permitting, energy efficiency, endangered species, climate change, sportsmen's issues, environmental pollution and regulations, air quality, and biofuels.

- Drafting legislation; building coalitions; negotiating policy solutions; writing speeches; staffing the Senator at hearings of the Agriculture and Finance Committees.

2014-2015 **U.S. Senate**, Washington, DC **AAAS Congressional Science Fellow**

- Competitively selected AAAS Fellow sponsored by the American Geophysical Union. Served in the Office of Senator Michael Bennet (D-CO).
- Drafting legislation; helping to facilitate political coalitions; meeting with constituents; interacting with federal agencies; delivering policy briefings and recommendations.

2012-2014 **University of Michigan**, Ann Arbor, MI **Postdoctoral Research Fellow**

- Successfully obtained competitive grant funding for novel method to track air pollution from power plants and metal smelters into rainfall across the Great Lakes region.
- In collaboration with epidemiologists, developed and utilized new methods to assess the sources and pathways of human exposure to mercury pollution.
- Published five manuscripts; presented talks and organized scientific sessions at national and international conferences.

2007-2012 **University of Michigan**, Ann Arbor, MI **Graduate Researcher**

- Competed for and received National Defense Science and Engineering Graduate Fellowship and Graham Environmental Sustainability Institute Doctoral Fellowship.
- Developed groundbreaking methods to "fingerprint" mercury pollution from coal-fired power plants and trace it into rainfall, lake sediments, and fish.
- Published eight manuscripts, was interviewed for "The Environment Report" on NPR and general-circulation science magazines, presented research at national and international conferences.
- Ph.D. dissertation received university-wide ProQuest Distinguished Dissertation Award and departmental John Dorr Graduate Academic Achievement Award.

2005-2007 **Massachusetts Institute of Technology**, Boston, MA **Research Scientist**

- Found evidence for early life on Earth in ancient rocks. Published two manuscripts.

SERVICE & LEADERSHIP:

2021-present **Board Member** of Zero Emission Transportation Association Education Fund Board
2020-present **Board Member** of University of Michigan Earth and Environmental Sciences Alumni Board
2019-2020 **Board Member** of Advancing Women in Energy
2017-2019 **Communications Chair** for Advancing Women in Energy
2013-2014 **Supported** the Ann Arbor Energy Commission on community solar projects
2009-2014 **Peer reviewer** of more than 20 scientific manuscripts
2009 **Initiator and organizer** of new departmental seminar series, University of Michigan
2008-2010 **President** of department student organization (GeoClub), University of Michigan
2008 **Lead organizer** of Michigan Geophysical Union Poster Conference
2007-2008 **Department Steward** to Graduate Employees Union, University of Michigan

---

EDUCATION:

Ph.D. 2012 Earth and Environmental Sciences, **University of Michigan** (GPA: 8.837 out of 9.0)

B.S. 2005 Geological and Environmental Science, **Stanford University** (GPA: 4.007 out of 4.33)

MPSC Case No: U-22058
Requester: CEOMEIBCIEI
Question No.: CEOMEIBCIEIDE-1.6b
Respondent: N. Foley
Page: 1 of 1

Question: 6. Refer to the direct testimony of Neal Foley at page 25, lines 19–20, which states that “the Company intends to issue an Energy Storage Request for Proposal (‘RFP’) to identify energy storage projects to be deployed under the CCAA.” b. Please detail the expected requirements for projects participating in the RFP.

Answer: The table below details the expected requirements of the RFP.

Energy Storage	**Requirements**
Technology	Energy Storage Technology Neutral
Size	Minimum 25 MW, 4-hour and 8-hour
Capacity	Up to 480 MW (55 MW of which is 8-hour+ duration) comprised of the following: ~310 MW Company Owned ~170 MW TA
COD	No later than March 31, 2029, with bonus points allotted for projects with a COD of December 31, 2028 or earlier
Location	Physically located in Michigan in MISO Zone 7 and electrically connected to the DTE distribution system or a transmission system operated by MISO
Contract Structure	Build Transfer Agreement (BTA) or Tolling Agreement (TA)
TA Term	15-year term

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.33a	
Respondent: K. Bilyeu	
Page: 1 of 1	

Question: 33. Refer to the direct testimony of Kevin Bilyeu at page 8, lines 9–10, which states that the "Customer has requested that the Company build up to 1.6 GW of renewable energy projects through a VGP special contract with DTE Electric." a. How does the Company propose to evaluate resources to fulfill this VGP Special Contract?

Answer: DTE Electric will issue an RFP as noted in Q31 for a minimum of 50% of the capacity required to fulfill the VGP Special Contract through build transfer agreements ("BTAs") with unaffiliated third parties consistent with the Section 61 Settlement Agreement in Case No. U-21172. The RFP will outline how resources will be evaluated. The Company has not yet determined if an RFP will be issued for self-build projects.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.1a	
Respondent: N. Foley	
Page: 1 of 1	

Question: 1. Refer to the direct testimony of Neal Foley at page 4, lines 9–12, which states "...the CCAA allows the Company to receive from the Customer 300 MW of Midcontinent Independent System Operator ('MISO') Zone Zonal Resource Credits ('ZRCs') at no cost." a. Does the Company plan to place any restrictions on the ZRCs it plans to receive from the Customer?

Answer: The "ZRC Product" is defined in the CCAA as "MISO Zone 7 Zonal Resource Credits in an amount equal to 300MW" (page A-12). The Company cannot place additional restrictions on the ZRCs beyond this definition. The Company is not involved in the Customer's procurement of the ZRCs that it will transfer to the Company and notes that the ZRCs are being transferred to the Company at no cost.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.8bi	
Respondent: N. Foley	
Page: 1 of 1	

Question: 8. Refer to the direct testimony of Neal Foley at page 31 lines 23–25… b. With regards to the timeline of June 1, 2028 to May 31, 2033, if the ZRCs that the Customer transfers to the Company are from resources that still have a useful life beyond May 31, 2033: i. What will happen to the ZRCs after 2033?

Answer: The Company is not involved in the Customer's procurement of the ZRCs that it will transfer to the Company. On an annual basis, the Customer will transfer ZRCs to the Company that are effective for the upcoming MISO planning year (i.e., June 1 to the following May 31).

Beyond May 31, 2033, the Customer is not obligated to transfer ZRCs to the Company and therefore the Company will not have access to such ZRCs.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-1.9c	
Respondent: N. Foley	
Page: 1 of 1	

Question: 9. Refer to the direct testimony of Neal Foley at page 32, lines 1–2, which states the "customer has agreed to pay the Company an amount based on the Financial Compensation Mechanism ('FCM') associated with the transfer of 300 ZRCs to the Company." c. Please explain why the Company believes that it is appropriate to record this amount as non-refundable income.

Answer: The "financial adder" described in my testimony is similar in structure to the FCM that the Company receives for PPAs that it enters into associated with third-party clean energy projects. As such, the Company believes it appropriate that the financial adder receive similar accounting treatment (i.e., be recorded as non-refundable income). The "financial adder" is intended to account for the opportunity cost of foregoing the development of a company-owned resource or a third-party resource that would receive an FCM, such as a PPA.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-5.1a	
Respondent: N. Foley	
Page: 1 of 1	

Question: 1. Refer to the rebuttal testimony of DTE Witness Bilyeu at 25, which states: “Rather, my testimony explains that the Customer elected to support renewable resources through a VGP Special Contract for 40% of its load, and that the associated renewable attributes will be tracked through RECs consistent with the applicable VGP framework.”a. Please provide additional detail regarding the structure of the VGP Special Contract. Is the Customer purchasing both the energy and the renewable attributes through the contract, or only the renewable attributes?

Answer: The VGP Special Contract as established through the CCAA is not a Power Purchase Agreement (PPA). Accordingly, the Customer is not purchasing energy through the VGP Special Contract. Instead, the Customer is paying for the renewable energy projects deployed under that agreement and in return is receiving (1) Renewable Capacity Credits (as defined in Exhibit A of the CCAA), (2) Renewable Generation Credits (as defined in Exhibit A of the CCAA), and (3) RECs (as governed by Section 4.3 of the CCAA).

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-5.1b	
Respondent: N. Foley	
Page: 1 of 1	

Question: 1. Refer to the rebuttal testimony of DTE Witness Bilyeu at 25, which states: "Rather, my testimony explains that the Customer elected to support renewable resources through a VGP Special Contract for 40% of its load, and that the associated renewable attributes will be tracked through RECs consistent with the applicable VGP framework."b. If the Customer is only purchasing the renewable attributes through the VGP Special Contract, please confirm that this means the customer is thus purchasing 100% of its energy needs through the PSA and outside of the VGP Special Contract.

Answer: Confirmed. All of the Customer's usage is subject to D11 as governed by the PSA, including surcharges.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-5.2a	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 2. Please refer to the rebuttal testimony of Company Witness Benyard at 2, which states: "However, ITC, the transmission owner and the party that will complete the stability study and short-circuit study, recently advised the Company that the stability studies are ongoing, though a date for finalization has not been determined, and screening-level short circuit analysis is complete."a. Please provide a copy of the screening-level short circuit analysis.

Answer: The Company does not possess or control access to the screening level short circuit study and as a general matter, ITC does not provide copies of such studies to the Company. The Company has requested a copy of the study from ITC, although has not received it as of the date of this response.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-5.2b	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 2. Please refer to the rebuttal testimony of Company Witness Benyard at 2, which states: "However, ITC, the transmission owner and the party that will complete the stability study and short-circuit study, recently advised the Company that the stability studies are ongoing, though a date for finalization has not been determined, and screening-level short circuit analysis is complete."b. Please clarify the meaning of "screening-level." Will additional short circuit analyses be conducted based on the result of the screening level analysis? If so, please provide the timeline for any additional analysis.

Answer: The Company does not know the meaning of "screening-level". ITC has not informed the Company that any additional short-circuit studies will be performed. However, as stated in my rebuttal testimony (p. 2, lines 11-22), ITC has not completed their studies and it is possible that additional short-circuit analysis may be necessary pending the results of the remaining studies.

Attachment: None

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-5.3a	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 3. Please refer to the rebuttal testimony of Company Witness Benyard at 2, which states: "DTE Electric will complete the EMT based transient simulations and estimates. That study has commenced and completion is estimated in the fall of 2026." Please provide the following information about the EMT study:a. Is the Company using a generic model, manufacturer-specific models, or both?

Answer: EMT based transient simulations will incorporate manufacturer-specific models as provided by the Customer.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-5.3b	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 3. Please refer to the rebuttal testimony of Company Witness Benyard at 2, which states: "DTE Electric will complete the EMT based transient simulations and estimates. That study has commenced and completion is estimated in the fall of 2026." Please provide the following information about the EMT study:b. If using a manufacturer-specific model, has this model been supplied by the Customer?

Answer: The manufacturer-specific model has not yet been supplied by the Customer.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-5.3civ	
Respondent: S. Benyard	
Page: 1 of 1	

Question: 3. Please refer to the rebuttal testimony of Company Witness Benyard at 2, which states: “DTE Electric will complete the EMT based transient simulations and estimates. That study has commenced and completion is estimated in the fall of 2026.” Please provide the following information about the EMT study:c. Will the Company be evaluating each of the following?iv. Interactions with inverter-based resources

Answer: Yes, interactions with inverter-based resources in close electrical proximity will be reviewed.

Attachment: *None*.

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.1a	
Respondent: K. Bilyeu	
Page: 1 of 1	

Question: 1. Refer to the rebuttal testimony of DTE Witness Bilyeu at page 19, which states: "in DTE Electric's 2024 All-Source Renewable RFP, Company-owned projects averaged approximately $75 per MWh, while third-party-owned projects average approximately $92 per MWh."
a. Please describe how Witness Bilyeu calculated the averages of $75 per MWh for Company-owned projects and $92 per MWh in his rebuttal testimony.

Answer: The $75 per MWh figure for Company-owned projects reflects the average of the four conforming Company-owned bids in Appendix A of Guidehouse Inc.'s Report on DTE 2024 Renewable Energy Request for Proposals (Company-Owned Lines 1-4), filed in Case No. U-21193, using the "LCOE (As Bid") column. Adjustments for contractual exception, financial compensation mechanism, and terminal value were not applied to the Company-owned bids because those bids did not require such adjustments.

The $92 per MWh figure for third-party-owned projects reflects the average of the 10 conforming PPA bids in Appendix A of Guidehouse Inc.'s Report on DTE 2024 Renewable Energy Request for Proposals (PPAs Lines 1-10), filed in Case No. U-21193, using the "LCOE (with estimated contractual exception, financial compensation mechanism, terminal value adjustments)" column, which properly accounts for the adjustments applicable to PPA bids.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.1b	
Respondent: K. Bilyeu	
Page: 1 of 2	

Question: 1. Refer to the rebuttal testimony of DTE Witness Bilyeu at page 19, which states: "in DTE Electric's 2024 All-Source Renewable RFP, Company-owned projects averaged approximately $75 per MWh, while third-party-owned projects average approximately $92 per MWh."

b. Refer to Guidehouse Inc.'s Report on DTE 2024 Renewable Energy Request for Proposals, which was filed by the Company in Docket No. U-21193 and is available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000012ojt7AAA. Appendix A to this report provides the following:

Project #	Tech-nology	Rounded MW (AC)	Structure	COD	Total Bid Score	LCOE (As Bid)	LCOE (with estimated contractual exception and financial compensation mechanism adjustments)	LCOE (with estimated contractual exception, financial compensation mechanism, terminal value adjustments)	Comment
COMPANY-OWNED									
1	Solar	100	Self	2027	3.7	$71			Currently in consideration
2	Solar	175	Self	2027	3.5	$73			Currently in consideration
3	Solar	125	Self	2027	3.3	$75			Currently in consideration
4	Solar	125	Self	2027	2.8	$80			Currently in consideration
5	Solar	200	Self	2027	0.0	$67			Non-Conforming
PPAs									
1	Solar	125	PPA	2027	5.1	$74	$84	$85	Currently in consideration
2	Solar	125	PPA	2027	4.8	$75	$85	$87	Duplicate, currently in consideration
3	Solar	100	PPA	2027	4.2	$76	$86	$87	Currently in consideration
4	Solar	100	PPA	2027	3.8	$79	$90	$91	Duplicate, currently in consideration
5	Solar	100	PPA	2027	3.5	$80	$91	$93	Duplicate, currently in consideration
6	Solar	100	PPA	2027	3.3	$80	$91	$92	Currently in consideration
7	Solar	100	PPA	2027	3.1	$81	$92	$93	Duplicate, currently in consideration
8	Solar	100	PPA	2027	3.1	$84	$96	$96	Duplicate, currently in consideration
9	Solar	100	PPA	2027	2.9	$83	$94	$95	Duplicate, currently in consideration
10	Solar	100	PPA	2027	2.7	$84	$96	$96	Duplicate, currently in consideration
11	Solar	75	PPA	2027	0.0	$74	$84	$87	Non-Conforming
12	Solar	150	PPA	2027	0.0	$28	$30	$30	Non-Conforming

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.1b	
Respondent: K. Bilyeu	
Page: 2 of 2	

Please confirm that Witness Bilyeu used the bid summary information contained in Appendix A to calculate the averages provided in his rebuttal testimony.

Answer: Confirmed. Please see the response to CEOMEIBCIEIDE-6.1a.

Attachment: *None.*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.1bi	
Respondent: K. Bilyeu	
Page: 1 of 2	

Question: 1. Refer to the rebuttal testimony of DTE Witness Bilyeu at page 19, which states: "in DTE Electric's 2024 All-Source Renewable RFP, Company-owned projects averaged approximately $75 per MWh, while third-party-owned projects average approximately $92 per MWh."

b. Refer to Guidehouse Inc.'s Report on DTE 2024 Renewable Energy Request for Proposals, which was filed by the Company in Docket No. U-21193 and is available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000012ojt7AAA. Appendix A to this report provides the following:

Project #	Tech-nology	Rounded MW (AC)	Structure	COD	Total Bid Score	LCOE (As Bid)	LCOE (with estimated contractual exception and financial compensation mechanism adjustments)	LCOE (with estimated contractual exception, financial compensation mechanism, terminal value adjustments)	Comment
COMPANY-OWNED									
1	Solar	100	Self	2027	3.7	$71			Currently in consideration
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3	Solar	125	Self	2027	3.3	$75			Currently in consideration
4	Solar	125	Self	2027	2.8	$80			Currently in consideration
5	Solar	200	Self	2027	0.0	$67			Non-Conforming
PPAs									
1	Solar	125	PPA	2027	5.1	$74	$84	$85	Currently in consideration
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10	Solar	100	PPA	2027	2.7	$84	$96	$96	Duplicate, currently in consideration
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12	Solar	150	PPA	2027	0.0	$28	$30	$30	Non-Conforming

MPSC Case No: U-22058

Requester: CEOMEIBCIEI

Question No.: CEOMEIBCIEIDE-6.1bi

Respondent: K. Bilyeu

Please confirm that Witness Bilyeu used the bid summary information contained in Appendix A to calculate the averages provided in his rebuttal testimony.

i. If confirmed, please confirm which Company-owned projects (identified by Project #) and PPA projects (identified by Project #) were used to calculate the cited averages.

Answer: Please refer to CEOMEIBCIEIDE-6.1a.

Attachment: *None.*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.1bii	
Respondent: K. Bilyeu	
Page: 1 of 2	

Question: 1. Refer to the rebuttal testimony of DTE Witness Bilyeu at page 19, which states: "in DTE Electric's 2024 All-Source Renewable RFP, Company-owned projects averaged approximately $75 per MWh, while third-party-owned projects average approximately $92 per MWh."

b. Refer to Guidehouse Inc.'s Report on DTE 2024 Renewable Energy Request for Proposals, which was filed by the Company in Docket No. U-21193 and is available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000012ojt7AAA. Appendix A to this report provides the following:

Project #	Tech-nology	Rounded MW (AC)	Structure	COD	Total Bid Score	LCOE (As Bid)	LCOE (with estimated contractual exception and financial compensation mechanism adjustments)	LCOE (with estimated contractual exception, financial compensation mechanism, terminal value adjustments)	Comment
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3	Solar	125	Self	2027	3.3	$75			Currently in consideration
4	Solar	125	Self	2027	2.8	$80			Currently in consideration
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PPAs									
1	Solar	125	PPA	2027	5.1	$74	$84	$85	Currently in consideration
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3	Solar	100	PPA	2027	4.2	$76	$86	$87	Currently in consideration
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MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.1bii	
Respondent: K. Bilyeu	
Page: 2 of 2	

Please confirm that Witness Bilyeu used the bid summary information contained in Appendix A to calculate the averages provided in his rebuttal testimony.

ii. If not, please provide all bid information and prices used by Witness Bilyeu.

Answer: Not applicable. Please refer to CEOMEIBCIEIDE-6.1b.

Attachment: *None.*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.2a	
Respondent: N. Foley	
Page: 1 of 1	

Question: 2. Refer to the rebuttal testimony of Witness Foley at page 36–37, discussing MEI/CEO Witness Sherman's recommendation to partially meet the ZRCs through utility programs. Witness Foley states: "The Company is not involved in the Customer's procurement of ZRCs that will be transferred to the Company as part of the CCAA. Under the CCAA, it is the Customer's obligation to provide the ZRCs and the source of those ZRCs is at their discretion."

a. Please confirm that one option for the Customer to procure the ZRCs could involve the Customer funding the expansion or creation of utility demand response or VPP programs.

Answer: Not confirmed. The CCAA requires the transfer of ZRCs from the Customer to the Company. However, the request as framed would require the Company itself to expand or create a utility program to generate the ZRCs that the Customer is contractually obligated to transfer. The expansion or creation of a Company program, even if it were to be funded by the Customer, is not contemplated by the CCAA. Section 7 of the CCAA sets forth the obligations of the Customer with respect to a ZRC transfer and the Company's compensation for the provision of those ZRCs. The expansion or creation of a utility program would include no such transfer since the ZRCs would be generated by the Company and would require entirely different compensation and tracking structures. Accordingly, such an approach would not comply with the terms of the CCAA, and therefore is not an option the Customer can pursue to satisfy the terms of the CCAA.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.2b	
Respondent: N. Foley	
Page: 1 of 1	

Question: 2. Refer to the rebuttal testimony of Witness Foley at page 36–37, discussing MEI/CEO Witness Sherman's recommendation to partially meet the ZRCs through utility programs. Witness Foley states: "The Company is not involved in the Customer's procurement of ZRCs that will be transferred to the Company as part of the CCAA. Under the CCAA, it is the Customer's obligation to provide the ZRCs and the source of those ZRCs is at their discretion."
b. If not, explain why the Company would preclude the Customer from pursuing such options.

Answer: See the response to CEOMEIBCIEIDE-6.2a. The Company is not attempting to "preclude" the Customer from pursuing such options. Such options do not comply with the CCAA and therefore cannot be used to satisfy the terms of the CCAA.

Attachment: *None*

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.3a	
Respondent: N. Foley	
Page: 1 of 1	

Question: 3. Refer to the rebuttal testimony of Foley at page 24, which discusses the information the Company believes should be provided in its annual report, including "[a] presentation of the aggregate costs and benefits of serving the customer as of the end of the previous."
a. If an annual report shows that costs exceed the benefits of serving the Customer for the previous year, please describe any steps the Company will take to recover those costs from the Customer pursuant to Section 5.1.3 of the PSA.

Answer: DTE Electric objects to this request as it seeks a legal conclusion, calls for speculation and is overly broad as it seeks an itemization of legal remedies the Company may or may not take in the future with respect to the special contracts. The Company further objects as the question mis-states the operation of PSA Section 5.1.3 which requires a review of the aggregate costs and benefits over the life of the contracts and not an annual retroactive reconciliation. Subject to and without waiving this objection, the Company responds as follows: See my revised direct testimony at questions 37 and 38 which discuss Section 5.1.3 of the PSA (the Affordability Backstop). Section 5.1.3 governs a situation under which the Commission finds that the aggregate costs of serving the Customer exceed the benefits of doing so. Under that section, if the Commission were to make such a determination, then the Customer "agrees to comply with any such ruling or order to ensure that Customer pays all costs associated with its service from Company."

Attachment: *None*

Co-respondent: Legal

MPSC Case No: U-22058	
Requester: CEOMEIBCIEI	
Question No.: CEOMEIBCIEIDE-6.3b	
Respondent: N. Foley	
Page: 1 of 1	

Question: 3. Refer to the rebuttal testimony of Foley at page 24, which discusses the information the Company believes should be provided in its annual report, including "[a] presentation of the aggregate costs and benefits of serving the customer as of the end of the previous."

b. Under what circumstances, if any, would the Company pursue its rights under the PSA's affordability backstop to recover costs from the Customer prior to the end of the life of the contracts between the Company and the Customer?

Answer: DTE Electric objects to this request as it seeks a legal conclusion, calls for speculation and is overly broad as it seeks an itemization of legal remedies the Company may or may not take in the future with respect to the special contracts. Subject to and without waiving this objection, the Company responds as follows**:** See response to CEOMEIBCIEIDE-6.3a. PSA Section 5.1.3 is not a unilateral Company-administered remedy. By its terms, Section 5.1.3 is invoked only upon a Commission ruling, or disallowance determining that the costs to serve the Customer exceed the combined benefits under the PSA, CCAA, and applicable related agreements. Thus, the circumstances under which Section 5.1.3 would result in Customer recovery are circumstances established through future Commission findings in contested regulatory proceedings, not circumstances the Company would pursue independently.

Attachment: *None*

Co-respondent: Legal

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE ELECTRIC COMPANY for approval of special contracts and for other relief.	)))	Case No. U-22058

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Official Exhibits and Exhibit List of The Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar; the Michigan Energy Innovation Business Council; and The Institute for Energy Innovation* were served by electronic mail upon the following Parties of Record, this Thursday, July 2, 2026.

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Michigan Environmental Council; Natural Resources Defense Council, Sierra Club *Christopher Bzdok *Sean C. Clark *Natasha Fowles *Sue Fruchey *Shannon Fisk *Jacob Elkin *Helen Li *Bryndis Woods *Joshua Castigliego *Holly Hillyer	chris@tropospherelegal.com sean@tropospherelegal.com natasha@tropospherelegal.com sue@tropospherelegal.com sfisk@earthjustice.org jelkin@earthjustice.org hli@earthjustice.org bryndis.woods@aeclinic.org joshua.castigliego@aeclinic.org holly@tropospherelegal.com

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* *Receives confidential material*

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