2023 Written Public Comments Submitted to the Grid Modernization Advisory Council

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Below are the written comments submitted to MA-GMAC@mass.gov in 2023. This document also includes written submissions of comments made at the two GMAC Listening Sessions on October 30, 2023, and November 1, 2023.

The GMAC received the following written comments from the following stakeholders:

1. Department of Energy Resources – Received 5/8/23
2. Barr Foundation – Received 6/9/23
3. Acadia Center – Received 6/9/23
4. Nexamp, Inc. – Received 6/9/23
5. Coalition for Community Solar Access – Received 6/9/23
6. Green Energy Consumers Alliance – Received 6/27/23
7. Solar Energy Business Association of New England (SEBANE) – Received 6/28/23
8. Department of Energy Resources – Received 6/29/23
9. New Leaf Energy – Received 6/29/23
10. Office of the Attorney General (AGO) – Received 6/29/23
11. Greg Hunt, ZPE Energy – Received 7/12/23
12. Rich Creegan, Anterix – Received 7/12/13
13. Cape Light Compact, submitted by Margaret Downey – Received 7/13/23
14. Advanced Energy United and Northeast Clean Energy Council (NECEC) – Received 7/13/23
15. Heather Deese, Senior Director of Policy & Regulatory Affairs for Dandelion Energy – Received 8/11/23
16. Undersecretary of Environmental Justice and Equity María Belén Power, Executive Office of Energy and Environmental Affairs – Received 8/14/23
17. Louise Amyot, Greenfield, MA Resident – Received 9/08/23
18. Craig Martin, Shutesbury, MA Resident – Received 9/13/23
19. Graham Turk, Massachusetts Institute of Technology graduate student – Received 9/14/23
20. Michael Savage, Vice President of Business Development of Vergent Power Solutions – Received 10/16/23
21. Advanced Energy Group’s Grid Modernization Task Force – Received 10/20/23
22. Amaani Hamid, Senior Regulatory Affairs Manager at Leap – Received 10/12/23 (Oral comments delivered at the 10/30/23 GMAC Listening Session)
23. Rachel Loeffler, Private Landowner in Eversource service territory – Received 11/1/23 (Oral comments delivered at the 10/30/23 GMAC Listening Session)
24. Cathy Kristofferson, Pipe Line Awareness Network for the Northeast – Received 11/1/23 (Oral comments delivered at the 11/1/23 GMAC Listening Session)
25. Joint comments from environmental and climate advocates in Massachusetts, submitted by Priya Gandbhir, Conservation Law Foundation – Received 11/1/23
26. Graham Turk, MIT Researcher and Eversource customer – Received 11/2/23 (Oral comments delivered at the 11/1/23 GMAC Listening Session)
27. Leslie Zebrowitz, Co-Chair of Newton EV Task Force – Received 11/3/23

28. NRG Energy, Inc, submitted by Greg Geller, Stack Energy Consulting – Received 11/7/23
29. Cape Light Compact, submitted by Margaret Downey – Received 11/7/23
30. Chief Mariama White-Hammond Environment, Energy and Open Space, City of Boston – Received 11/13/23
31. Tim Snyder, NECEC – Received 11/16/23
32. Silas Bauer, OnSite Renewables – Received 11/16/23
33. John Greene, Policy and Regulatory Affairs Manager of Piclo – Received 11/17/23
34. Steve Letendre, PhD, Senior Director of Regulatory Affairs, Fermata Energy – Received 12/12/23
35. Audrey Schulman, HEET (Home Energy Efficiency Team) – Received 12/12/23

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Maura T. Healey
Governor

Kimberley Driscoll
Lt. Governor

Rebecca L. Tepper
Secretary

Elizabeth Mahony
Commissioner

May 8, 2023

RE: Initial Recommendations on the Electric Distribution Companies' Electric-Sector Modernization Plans

To Whom It May Concern:

Pursuant to G.L. c. 164, §§ 92B-92C, the Grid Modernization Advisory Council (GMAC) is charged with reviewing and providing recommendations to the state's investor-owned electric distribution companies' (EDCs) electric-sector modernization plans (ESMPs). The GMAC and ESMP system stem from the 2022 landmark law, "An Act Driving Clean Energy and Offshore Wind" (Climate Law). The Climate Law requires that the state's EDCs prepare the ESMPs to proactively upgrade the distribution system and meet multiple objectives, including:

- Improve grid reliability, communications, and resiliency;
- Enable increased, timely adoption of renewable energy and DERs;
- Promote energy storage and electrification technologies for decarbonization;
- Prepare for climate-driven impacts on transmission and distribution ("T&D") systems;
- Accommodate transportation and building electrification, and other new loads; and
- Minimize or mitigate impacts on ratepayers.

The Commonwealth's Clean Energy and Climate Plan for 2050 (2050 CECP) lays out a comprehensive and aggressive plan to achieve net zero greenhouse gas emissions. The dominant strategy to decarbonize transportation and buildings is electrification, thereby making power sector planning essential. Distribution system planning is necessary to understand the need, cost, and benefits of upcoming grid-side investments especially because these investments have significant cost and long-term implications for the power system. The GMAC and ESMP system represent an opportunity for transparent and comprehensive integration of distribution system planning that engages a broad set of stakeholders, including policymakers and regulators.

As the Chair of the GMAC, and as the state energy office charged with developing and implementing policies and programs aimed at ensuring the adequacy, security, diversity, and cost-effectiveness of the Commonwealth's energy supply to create a clean, affordable and resilient energy future, the Department of Energy Resources (DOER) is invested in developing ESMPs that meet all the objectives outlined in the Climate Law and in the 2050 CECP.

The timeline set by the Legislature in the Climate Law is rapid, requiring the EDCs to submit draft ESMPs to the GMAC for review by September 1, 2023. The EDCs must then file final ESMPs, inclusive of GMAC feedback, with the Department of Public Utilities (DPU) by January 29, 2024. In the interest of providing initial guidance to the EDCs as they develop their first draft plans, DOER suggests the following recommendations.

Recommendations

1. **The ESMPs should include a comprehensive and clear synthesis of existing investment areas, implementation plans, future planned investments, and ongoing metrics reporting.** Non-technical stakeholders should be able to read and understand key utility investments, the timeline on which they will occur and why, and the EDC planning process. The Climate Law requires that the ESMPs "consider and summarize all proposed and related investments and alternatives that have been reviewed, are under consideration, or have been previously approved by the Department." This all-inclusive synthesis effort is a critical component of the ESMPs and aligning current and future investments with planning processes. The EDCs should be clear in what is and is not included in their review, with specific references to publicly available data and maps, dockets, timelines, working group scopes, and anything else part of the distribution system planning process in the Commonwealth.

   DOER recommends the EDCs synthesize investments, programs, and timelines from areas including but not limited to:

   - Grid modernization (D.P.U. 21-80/81/82-A, D.P.U. 21-80/81/82-B, and dockets D.P.U. 22-40, 41, 42),
   - Electric vehicle charging infrastructure programs (D.P.U. 21-90/91/92-A),
   - Utility-owned storage investment plans (D.P.U. 20-69-A),
   - Long-term system planning (D.P.U. 20-75-C),
   - Provisional System Program capital investment projects (CIPs) (dockets D.P.U. 22-47, 22-51, 22-52, 22-53, 22-54, 22-55, 22-61, 22-170, 23-06, 23-09, 23-12),
   - Energy Efficiency Three-year plans (D.P.U. 21-120-21-129).
   - Rate cases (D.P.U. 18-150, D.P.U. 19-130, D.P.U. 22-22, and any proposals contained in a pending base rate case),
   - Performance-based ratemaking schemes as approved in D.P.U. 18-150 and D.P.U 22-22, and
   - Distribution system reliability and safety dockets (such as the Annual Planning and Reliability Report, reporting of outage events, Service Quality Performance Reports, and vegetation management programs).

   Existing and new working groups should also be summarized and synthesized including the Energy Storage Interconnection Review Group (ESIRG), the Technical Standards Review Group (TSRG), the advanced metering infrastructure stakeholder working group, clean energy transmission working group (CETWG), among others. Dockets that impact aspects of distribution system planning should also be considered, for example any impacts to electrification load from the future of gas proceeding (D.P.U. 20-80).

   Several states across the U.S. have implemented integrated distribution system planning processes that seek to coordinate policy goals and objectives, distribution system investments, long-term planning processes, and transparent stakeholder engagement. These examples, and resources provided through the U.S. Department of Energy, should serve as a foundation of knowledge for the EDCs to reference.[1]

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[1] See, for example, the Training Webinars on Electricity System Planning provided by the New England Conference of Public Utility Commissioners (NECPUC) and National Association of Regulatory Utility Commissioners (NARUC); the Modern Distribution Grid Project provided by U.S. DOE's Office of Electricity Delivery and Energy

2. **A common template and formatting should be used across the EDC ESMPs**. The EDCs should use a common template and format for their electric-sector modernization plans that is clear, in plain-language, and comprehensive. Technical terms should be clearly defined in an appendix and when referenced for the first time in text. DOER, in collaboration with the GMAC and EDCs, proposes to support the development of a template to share with the DPU.

3. **The EDCs should develop and define a process that provides updates for stakeholders on the status of proposed EDC ESMP strategies and timelines throughout the five-year cycle.** Many electric utility functions and components are changing as the EDCs evolve to fully integrate DERs into their operations and business models. The EDCs are required to submit two reports per year to the DPU and the Joint Committee on Telecommunications, Utilities, and Energy on the deployment of approved investments in accordance with any performance metrics included in the approved plans. The EDCs should also provide updates to stakeholders outside of any adjudicatory proceedings. Updates to the ESMP will serve to fully and clearly describe the status of processes and tools used or proposed by the EDCs as well as those currently or soon to be provided to DER developers/operators and other stakeholders tracking electrification. The EDCs should identify and propose appropriate working groups for issues or barriers identified in the ESMPs, including but not limited to interconnection, building electrification, and forecasting. The EDCs should define how any existing and proposed working group contributes to the ESMPs. Updates communicated to the GMAC and other stakeholders should include a report on progress, detailed description of implementing all necessary policies, processes, resources, and standards, and a description of how the ESMP planning and implementation efforts are organized and managed. Electric utilities in New York State, for example, submit Distribution System Implementation Plans every five years with updates to the plans every two years.[2]

4. **The EDCs should provide all relevant non-confidential and non-critical energy infrastructure information and data to the GMAC as appropriate to facilitate stakeholder review of information that will likely be subject to discovery at the DPU during ESMP review.** It is important that the GMAC, the DPU, and the EDCs coordinate to identify necessary data and information needed to support review of a the ESMPs. Having a complete record of the data used to prepare the ESMP in advance of the September 1st deadline for GMAC review will not only facilitate GMAC review, but the subsequent adjudicatory review by all intervenors and the DPU, both of which face compressed timelines for action. Data should be provided in a consistent format across EDCs in unlocked excel spreadsheets with all equations in cell links active and included. Due to challenges associated with sharing confidential and critical energy infrastructure information (CEII), including potential security and competitive advantage risks, it is the recommendation of DOER that data and information requests from the GMAC are limited to non-confidential and non-CEII data. The EDCs should endeavor to provide responsive data and information in such a way as to facilitate ESMP review within this limitation.

5. **The EDCs should propose a robust stakeholder engagement process in their ESMPs.** The GMAC is one avenue for stakeholder engagement but should not be the sole stakeholder entity engaged by the EDCs. The Climate Law requires that EDCs conduct technical conferences and at least two stakeholder meetings to inform the public, state and federal agencies, and companies

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Reliability and the Pacific Northwest National Laboratory; and some recent integrated distribution system plans from New York, Colorado, Michigan, Minnesota, and Oregon.

[2] See the New York Distributed System Implementation Plans here: https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips.

involved in “developing & installing distributed generation, energy storage, vehicle electrification systems, and building electrification systems.” Given the anticipated impact on communities of ESMP infrastructure build-out, continued stakeholder engagement and an inclusive outreach approach to communities is paramount to an open and transparent distribution system planning process. Particular attention must be paid to environmental justice communities who too often bear an unequal burden in hosting energy infrastructure yet are slow to directly benefit from the very decarbonization and clean energy assets the Commonwealth’s climate goals focus on.

6. **The EDCs should prioritize strategic planning in the first ESMP process.** There are benefits to limiting the ESMPs to be a strategic planning document that seeks to meet the objectives as written in the Climate Law, coordinate the multiple investment streams, propose future investments, and ensure stakeholder engagement and input. Such a process implicates the various DPU proceedings through which the adjudication of cost recovery of investments proposed in the ESMP are appropriate. DOER suggests that the ESMPs should be the central distribution system planning document and in any filing in which the EDC is requesting cost recovery they include a reference between their requested expenditures and their investment planning and timelines as submitted in their ESMPs.

7. **The EDCs should include a discussion of investment alternatives and alternative approaches to financing investments, and clearly communicate any proposed changes to stakeholders.** The Climate Law explicitly requires the EDCs to discuss investment alternatives (including ratemaking treatment changes, load management, flexible demand, dispatchable demand response) and alternative approaches to financing investments (like cost allocation between developers and ratepayers, and equitable allocation/sharing of costs across other states/populations). Given advancing technologies and ratemaking treatment methodologies, as well as challenges in siting and constructing infrastructure, ESMPs should explore such alternatives to traditional utility investment and ensure that investments minimize or mitigate impacts on ratepayers. These will be important components of distribution system planning and the ESMPs present an opportunity for a transparent and open discussion between the EDCs and the stakeholder community in advance of cost recovery proceedings and support consistent rate design between companies.

DOER looks forward to further discussions with the GMAC members, the electric distribution companies, and other interested stakeholders as the ESMPs are developed and finalized for submission to the Department of Public Utilities.

Signature,

Elizabeth Mahony

Elizabeth Mahony
Commissioner
Massachusetts Department of Energy Resources

Stakeholder Comments

Received by MA-GMAC@mass.gov by Friday June 9, 2023

Pertaining to the Electric Sector Modernization Plan: EDC Draft Proposed Structure (June 1, 2023)

Accessible at: https://www.mass.gov/doc/gmac-prereadesmp-draft-outline/download

Compiled comments

1. Barr Foundation
2. Acadia Center
3. Nexamp, Inc.
4. Coalition for Community Solar Access

FEEDBACK ON ESMP OUTLINE

TO: EDCs and Grid Modernization Advisory Council (GMAC)

FROM: Kathryn Wright

DATE: June 9th, 2023

Thank you for the opportunity to provide early feedback on the outline for the electric sector modernization plans (ESMPs). After reviewing, there are areas where I have comments or clarifying questions. My first set of comments cover cross-cutting topics in the outline.

- **Stakeholder versus Community Engagement:** Early in the document, the outline references stakeholder engagement for different customer classes. The ESMP's require both stakeholder and community engagement. There is a difference between the stakeholder engagement processes that the EDCs participate in with the GMAC and the public process that will be necessary for cities and towns hosting future ESMP projects. To be responsive to community needs, the ESMPs will require both public education and early consultation in cities and towns with projected infrastructure needs. The Attorney General's Office recently released a set of recommendations from a working group focused on increasing public participation in energy regulatory processes. While the target of these recommendations are the Department of Public Utilities and Energy Facilities Siting Board, the sections on "Information and Knowledge Accessibility" and "Reforming Public Engagement Approaches" contain best practices which can be applied to EDC engagement process.
- **Environmental justice versus disadvantaged communities:** The outline uses environmental justice and disadvantaged communities interchangeably. These terms are not interchangeable in some state and federal contexts. Can the EDCs clarify the definitions for these terms? How will these communities overlap or differ from the communities targeted by the Mass Save Communities First Partnership or who have been underserved by energy efficiency investments to date?
    - Ideally, if multiple incentives or investments are serving the same jurisdictions, applications and engagement processes should be streamlined between ESMPs, Mass Save and other initiatives.
- **Resilience:** The outline references resilience and reliability throughout, but the state's *Climate Assessment* and *Hazard Mitigation and Climate Adaptation Plan* are not listed as reference documents in the opening section. This is relevant because there are differences in the way the EDCs are regulated to think about resilience and reliability (e.g. SAIDI and CAIFI) and how the public and state think about climate resilience.
    - For example, if current energy rates make it unaffordable to optimally heat or cool a residence during extreme weather events, occupant discomfort and health risks would not count towards an EDC system or customer disruption metric. However, health risks from heat exposure are priority climate impacts discussed in the state's 2022 Climate Assessment. A broader consideration of resilience and reliability would be in alignment with the state.

Additionally, it would be helpful if the EDCs could surface what climate projections they are using and if they differ from the state.

- **Transparency and Accountability:** We have not had a chance to discuss what the public reporting process will be between the 5-year ESMP planning cycles. Given the proposed level of investment, at a minimum the public should be able to easily access information about any planned ESMP projects in their city or town and any ongoing engagement processes.

Lastly, I have clarifying questions and comments on specific sections.

- **5.1 Electric Sector Projections:** The outline references projections by jurisdiction. Can you please clarify what jurisdiction means in this context? I am unsure if this is referring to EDC territories, cities or towns or something else. It would be helpful to understand the granularity we should expect in the ESMPs.
- **8.2 Transport:** Thank you for your prompt response to the information request to provide further detail on your electrification projections. Based on my reading of the document, the focus of the transportation projections seems to be light and/or medium-duty electric vehicles. It is unclear from the outline or the information request how transit electrification is being factored into the analysis. The 2022 Climate Act established a 2040 electrification target for the MBTA. The electrification of the MBTA, RTA and fleets will have differing impacts on the grid than LDVs. Mass transit is the primary mobility mode for many residents of Massachusetts cities. Can the EDCs clarify if these transit targets are incorporated into their analysis and planning? Will this be discussed in the ESMP document?
- **9.2 Decarbonized Gas:** The references to hydrogen and biogas conflict with the state's 2050 Climate Roadmap which emphasized that the most cost-effective application of these fuels was in energy dense applications such as industrial processes and aviation. In addition, both technical experts and community group expressed concerns about the health, safety risks, and emissions impacts of deploying biogas and hydrogen in buildings in our communities within the Future of Gas docket (an example joint comment letter is linked here). Given this, I believe the other solution sets in Section 9 should be the focus of the ESMPs.
- **12.3 Training:** Is the workforce training referenced in this section referring to Mass Save training programs or a new initiative? Will these training programs incentivize job creation and job placement within the targeted communities referenced earlier in the outline?

Thank you again for the opportunity to provide feedback. I look forward to discussing the outline and to continued collaboration.

Sincerely,
Kathryn Wright

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June 9, 2023

Grid Modernization Advisory Council
100 Cambridge Street, 9th Floor
Boston, MA 02114

Re: **Feedback on Electric-Sector Modernization Plans**

Dear Grid Modernization Advisory Council members,

Acadia Center appreciates the opportunity to offer feedback on the draft outlines for the Electric-sector Modernization Plans provided by the Electric Distribution Companies (EDCs). While consumer-oriented technology has raced forward in recent years, the energy grid that underpins the Northeast's economy has not. Aging infrastructure, the regulatory structure that governs utilities, the planning and investment policies, and the focus on increasing supply-side resources (rather than decreasing demand) all date from an era when energy came only from large fossil-fueled power plants, and customers had little choice about their energy.

This draft plan outline represents an important first step to modernize our grid into one that is responsive and flexible. While Acadia Center appreciates the provided draft plan outline, we do have comments and questions that may improve this draft and the process overall. Additionally, Acadia Center would like to express our support for the comments provided by the Barr Foundation.

- Acadia Center wishes to stress the urgency of building infrastructure <u>in advance</u> of customer need. This will require both anticipating customer demand and doing it in larger and integrated sections that incorporate aspects such as solar, EV load, heat pumps, batteries, and housing growth. While it may be difficult to ask the EDCs to incorporate every potential load growth scenario (such as a new housing development) every piece of additional information added to modeling has the potential to create more reliable predictions and a more responsive system.
- Acadia Center believes it is important that the Grid Modernization Advisory Council is afforded the opportunity to review and comment on the assumptions and forecasts that the EDCs are making before the plans are fully drafted.
- Battery storage should be specifically identified as a part of the demand forecast and considered as a resource on the supply side, as well.
- Demand forecasts should have more granularity beyond jurisdictional level. Forecasts should have a range of sensitivities (e.g. around electrification levels), as well as more granularity based on season and geography. Simply looking at annual peak will not show needed complexity or potential solutions.

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- It may be prudent to include a section on rate design in the forecast area, given the effect of different rate designs on the potential deployment of different technologies.
- Will ISO-NE's CELT forecast reports be considered as another input when doing this analysis?
- Will the subsection on non-wire alternatives identify opportunities for partnerships with third-parties among the solution set?

Acadia Center appreciates the opportunity to offer this feedback on the draft outlines for the electric-sector modernization plans and thanks the EDCs for their work. If you have any questions or concerns, please do not hesitate to reach out.

Sincerely,

Kyle Murray
Massachusetts Program Director and Senior Advocate
Acadia Center
kmurray@acadiacenter.org
617-742-0054 x106

nexamp

June 09, 2023

Dear Commissioner Mahony and Members of the Grid Modernization Advisory Council,

The modernization of the electrical grid is essential for the effective integration of renewable energy sources and the transition to a sustainable energy future. In Massachusetts (MA), as in other regions, solar developers play a crucial role in the deployment of solar energy systems.

Collaborative Successes in Other Markets:

Experience from other markets demonstrates that intense and sustained collaboration between solar developers and utilities has yielded positive results in grid modernization efforts. For instance, in California, collaborative efforts between solar developers and utilities resulted in streamlined interconnection processes, standardized technical requirements, and improved system planning. Similarly, states like New York and Hawaii have successfully engaged solar developers in grid modernization discussions, leading to innovative policies and effective integration of distributed solar resources. These collaborative models demonstrate the value of involving solar developers in shaping grid modernization plans.

Taking a look at New York in particular, the state has been implementing a comprehensive grid modernization strategy known as Reforming the Energy Vision (REV). As part of this initiative, the New York State Public Service Commission (PSC) has actively engaged solar developers and other stakeholders to transform the electricity market and enable greater integration of clean energy resources. Solar developers have participated in various working groups and collaborative processes to provide feedback on grid planning, market design, and regulatory reforms. Through these efforts, solar developers have influenced the development of policies such as the Value of Distributed Energy Resources (VDER) framework, which aims to fairly compensate distributed energy resources like solar for the value they provide to the grid. The engagement of solar developers has contributed to innovative approaches for grid modernization and accelerated the deployment of solar energy in New York.

Uniquely Situated to Provide Feedback:

Solar developers possess valuable insights and expertise that make them uniquely qualified to provide feedback on grid modernization plans. Here are some key reasons:

- System-Level Understanding: Solar developers have an in-depth understanding of solar technologies, deployment challenges, and system requirements. Their expertise in interconnection processes, grid integration, and solar project development enables them to assess the impact of grid modernization initiatives accurately.

- Real-World Experience: Solar developers are on the front lines of renewable energy deployment. They encounter various technical, regulatory, and operational issues during project development. This hands-on experience equips them with practical knowledge and unique perspectives on how grid modernization plans can effectively address challenges and optimize solar integration.
- Market Insights: Solar developers have extensive market knowledge inside and outside the Commonwealth, with insights into evolving trends, technologies, and customer preferences. Their understanding of market dynamics can contribute to the development of grid modernization plans that align with the needs of solar developers and enable the growth of solar energy in MA.
- Innovative Solutions: Collaborating with solar developers can foster innovative solutions for grid modernization. Developers often employ advanced technologies and practices, such as energy storage, demand response, and microgrids, to enhance solar system performance and grid integration. Their expertise in these areas can inform grid modernization plans, enabling the adoption of cutting-edge solutions.

Involving solar developers in the ideation of grid modernization plans in MA can yield substantial benefits. Drawing from successful collaborations in other markets, MA can harness the expertise and insights of solar developers to develop effective grid modernization strategies. By actively engaging solar developers, MA can leverage their system-level understanding, real-world experience, market insights, and innovative solutions to optimize the integration of solar energy, facilitate a smooth transition to renewable resources, and ensure a resilient and sustainable electrical grid for the future.

Thank you for the opportunity to provide feedback on the EDC's draft ESMP Outline. Nexamp looks forward to continued participation in this initiative moving forward.

Sincerely,

Benjamin Piiru
Director, Grid Integration
Nexamp, Inc.

June 9, 2023

Dear Commissioner Mahony and members of the Grid Modernization Advisory Council,

Thank you for the opportunity to review and provide comments on the draft EDC Electric System Modernization Plans (ESMP) outline. We greatly appreciate the open stakeholder process on the plans, as they will shape the Commonwealth's ability to decarbonize at the scale and speed needed to address the climate crisis in an affordable, equitable manner.

The Coalition for Community Solar Access (CCSA) is a national Coalition of businesses and non-profits working to expand customer choice and access to solar for all American households and businesses through community solar. Our mission is to empower every American energy consumer with the option to choose local, clean, and affordable community solar. We work with customers, utilities, local stakeholders, and policymakers to develop and implement policies and best practices that ensure community solar programs provide a win, win, win for all, starting with the customer.

CCSA appreciates that the draft ESMP outline contains the major key elements as required under last year's An Act Driving Clean Energy and Offshore Wind ("Climate Law"). Upon review of the outline, CCSA recommends the consideration of the following additional items and comments:

- Section 4.2: Current State of the Distribution System - Sub-region 1
    - Add "battery storage, standalone and integrated with DER"
    - Add "grid services" - this could include demand response, time-based retail electric pricing, smart inverter controls, and more
- Section 5.2: 5- and 10-year Electric Demand Forecast - Sub-region 1
    - Add forecasts for growth of battery storage (standalone and coupled with DER)
    - Add forecasts for grid services (see above; including but not limited to responsive load)
- Section 6: 5- and 10-year Planning Solutions: Building for the Future
    - CCSA recommends a full subsection here to discuss cost allocation approaches and options. Cost allocation is a very important topic and warrants a deep dive on the considerations and tradeoffs to various approaches from a holistic, policy driven perspective before considering

what the appropriate cost allocation approaches are to specific regional investments.

    - 6.1 "Summary of existing investment areas and implementation plans (existing asset management and core investments, including EV and EE programs)"
        - Ensure that this includes any approved CIP upgrades
    - 6.5 Sub-region 1
        - Distribution and transmission study timeline improvements for interconnection of DER
- Section 8: 2035 - 2050 Policy Drivers: Electric Demand Assessment
    - It may be appropriate in this section to add forecasts for large-scale onshore renewables and transmission projects
- Section 9.6: Alternative cost-allocation and financing scenarios – impact on investments
    - CCSA recommends that solar and storage should not necessarily be treated as distinct in these processes. The CIP 2.0 should examine how storage and solar can enable each other and provide additional capacity by offsetting or deferring utility upgrades.

Please do not hesitate to reach out if you have any questions about these comments or if we can be of any assistance to the GMAC.

Sincerely,

Kate Daniel
Northeast Regional Director
Coalition for Community Solar Access

Stakeholder Comments

Received by MA-GMAC@mass.gov by Thursday June 29, 2023

Pertaining to the Electric Sector Modernization Plan: EDC Draft Proposed Structure (June 1, 2023)

Accessible at: https://www.mass.gov/doc/gmac-prereadesmp-draft-outline/download

Compiled comments

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COMMONWEALTH OF MASSACHUSETTS
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Lt. Governor

Rebecca L. Tepper
Secretary

Elizabeth Mahony
Commissioner

June 29, 2023

Feedback on the EDC Draft Proposed Structure for the Electric Sector Modernization Plans

The Department of Energy Resources (DOER) thanks the electric distribution companies (EDCs) for their draft proposed structure for the electric sector modernization plans (ESMPs). The GMAC and ESMP system represent an opportunity for transparent and comprehensive integration of distribution system planning that engages a broad set of stakeholders. At the June GMAC meeting, the Council discussed the draft ESMP outline, invited written comments and anticipates continued review and input at the July GMAC meeting. DOER offers the following preliminary comments and questions on the proposed ESMP outline[1], organized by section below.

Section 1: Executive Summary

- Please include a table of contents with page numbers at the start of each ESMP.
- Sub-section 1.5: What investments will be included in this summary? Is the intention to provide a table with all approved, pending, and new proposed investments?

Section 3: Stakeholder Engagement

- The EDCs are required to hold two technical sessions before filing the ESMPs with the DPU in January. It would be useful for the GMAC to know what timeline the EDCs are planning on for these sessions. DOER encourages the EDCs to provide a timeline for these sessions to the Council, for discussion at the July GMAC meeting.
- Given the various stakeholder groups underway, both at the direction of the DPU and legislature or voluntarily, include in this section a list of ongoing and new proposed stakeholder working groups, with summaries of working group goals, objectives, and timelines, that touch distribution system planning areas.

Section 4: Current State of the Distribution System

- Please include a summary of key challenges facing the distribution system in this section.
- DOER understands that each EDC defines sub-regions in their territories differently. Please be sure to clearly introduce sub-regions and how they are determined and defined as clearly as possible.

[1] Version dated June 1, 2023 and accessible online at https://www.mass.gov/doc/gmac-prereadesmp-draft-outline/download.

- Accessibility to ESMPs is important to non-technical stakeholders. In this section, and to the greatest extent possible throughout all sections of the ESMPs, please use plain language that is approachable for non-technical audiences. If there are more technical elements that cannot be explained clearly in plain language, we suggest linking to other technical documents to further describe any needed elements.

Section 5: 5- and 10-year Electric Demand Forecast

- All assumptions behind the EDC forecasts should be clearly described. The EDCs should coordinate this section such that they list similar assumptions (or at least similar categories of assumptions) using the same names and in the same order. Where assumptions differ it would be useful to make that clear as well. Please provide a comparison table for forecasting assumptions across the EDCs.
- DOER recommends adding energy storage as a subsection, highlighting the unique challenges for the technology, including interconnection and operational limitations, but also the potential benefits energy storage could provide, including as a non-wires alternative.
- To strengthen coordinating stakeholder engagement and improving processes for the future, DOER recommends identifying a process to engage stakeholders to ensure forecasts and methodologies are aligned across the Commonwealth (and ISO-NE region) and updated to current technologies and processes and technical potential. Where the EDCs have dissimilar forecasting assumptions or methodologies, this kind of process could help unify forecasting methods.

Section 6: 5- and 10-year Planning Solutions: Building for the Future

- The summary of existing investment areas and implementation plans notes the electric vehicle and energy efficiency programs but no other plans. The EDCs should include other future plans, like grid modernization plans, rate case investments, decarbonization, heating and energy efficiency programs, here in this section.
- Under the “Technology platforms we are implementing” subsection, the EDCs should include a summary of each of the mentioned platforms (AMI, VVO, FLISR, ADMS, DERMs, etc.) and a description of the implementation justification and expected benefits to the EDC, the distribution system, ratepayers, and the Commonwealth.
- Sub-region 1 includes sections on “Alternative cost allocation to interconnect solar projects” and “Alternative cost allocation to interconnect battery storage projects” but no other sections include these sub bullets. Clarify why the EDCs do not include those subsections in the other sections and consider alternative approaches.
- The subsection for sub-regions includes non-wires alternatives. Include plans for integrating demand response, virtual power plants, and flexible resources.
- DOER understands the current ESMP outline does not address data access or availability yet because as the EDCs implement all of the abovementioned technology platforms, data will become an integral component of maximizing the benefits of AMI and other grid modernization investments. The EDCs should include a description of what a uniform statewide data access strategy and process might look like for the Commonwealth. Examples include New York, which has a Distribution System Data Portal that transparently displays the utility system capabilities, needs, limitations, and opportunities for DERs, and developing plans in New Hampshire.

Section 7: 5-Year ESMP

- This section includes a sub-section on "Alternatives to proposed investments". Describe the EDCs' plans for integrating demand response, virtual power plants, and/or flexible resources. The EDCs should include an estimate for how many megawatts they expect to manage/defer through alternatives to proposed investments.

Section 8: 2035-2050 Policy Drivers: Electric Demand Assessment

- As noted in Section 5, it's important that all the assumptions behind the EDC forecasts are clearly described. The EDCs should coordinate this section such that they list similar assumptions (or at least similar categories of assumptions) using the same names and in the same order. Where assumptions differ, the ESMPs should make that clear as well. DOER suggests including a comparison table for forecasting assumptions across the EDCs.

Section 9: 2035 - 2050 solution set – Building a decarbonized future

- In sub bullet 9.1 on "Behind the meter incentive design scenarios", the EDCs should discuss how they plan to implement building demand response or EV demand management at a greater scale. If available, the EDCs should include any studies or findings on what kind of impact BTM design can have on distribution grid operation on substation deferral.
- To the extent possible, DOER requests the EDCs include a description of their vision to incorporate greater demand response, load flexibility, and DER aggregation for the distribution system as well as near term action plans to enable the vision.
- The EDCs should detail what applications and in what quantity decarbonized gas solutions are incorporated in its planning?

Section 10: Reliable and resilient distribution system

- The EDCs should highlight how they plan to maintain and improve their resilience/reliability in light of climate change and the findings from the Asset Climate Vulnerability Assessment.
- DOER recommends the EDCs include the frameworks and/or processes used in thinking about enhancing resilience and reliability of the distribution system.

Section 11: Integrated gas-electric planning

- Please include a summary of key challenges when considering integrated gas-electric planning.
- Please include a list of ongoing and new proposed work related to gas-electric planning, including stakeholder working groups, with summaries of goals, objectives, near- and mid-term actions, and timelines.

Section 12: Workforce, Economic, and Health Benefits

- To the extent identified, include the barriers for building a workforce capable of building, operating, and maintaining the distribution grid up through 2050. Detail what they are and what actionable solutions are the EDCs considering.
- Detail plans to develop pathways for young talent to enter the distribution system/grid modernization workforce. (Connections with trade school programs, specialized community college certificates, student networks, etc.)
- Detail plans to recruit within EJ communities, including the steps available to provide EJ community members with opportunities to enter this field.

<u>Section 13: Conclusion</u>

- Clearly list all existing and ongoing reporting and metrics requirements for the distribution system in the ESMPs, with references or links to ongoing reporting processes. The EDCs should coordinate this section such that they propose a list of metrics and reporting requirements that are similar using the same names and in the same order to the greatest extent possible.

DOER looks forward to further discussions with GMAC members, the electric distribution companies, and other interested stakeholders as the ESMPs are developed and finalized for submission to the Department of Public Utilities.

Signature,

Elizabeth Mahony

Commissioner

Massachusetts Department of Energy Resources

GREEN ENERGY CONSUMERS ALLIANCE

June 27, 2023

Grid Modernization Advisory Council
100 Cambridge Street, 9th Floor
Boston, MA 02114

Re: Comments on Electric Sector Modernization Plans (ESMP)

Dear Commissioner Mahony and Grid Modernization Advisory Councilors:

Green Energy Consumers Alliance appreciates the work of the Council on the critically important effort to ensure that the Commonwealth's electric grid will contribute to climate change solutions that will enable Massachusetts to equitably meet its ambitious decarbonization goals. Our comments on the ESMP outlines are as follows:

Community Engagement:
Green Energy strongly supports comments of the Barr Foundation and participants in the June 15 meeting that community engagement—specifically outreach to and input from municipalities—is a critical aspect of this work. We also agree with the posted comments by the Barr Foundation dated June 9.

Municipalities and Aggregation:
Municipalities have much to contribute to grid modernization, and should be recognized as important partners in this effort. Many cities and towns have been using Green Communities and Municipal Vulnerability Preparedness grants to increase energy efficiency and prepare for climate change impacts. Frequently these activities include grid-related items such as development of a microgrid to provide shelter and keep the municipal campus running. Some have developed innovative proposals to switch low and moderate-income households to solar power and heat pumps. Municipalities also know and regularly reach out to their citizenry, particularly including middle- and low-income residents and environmental justice communities.

Another critically important aspect of municipalities' involvement concerns Municipal or Community Choice Aggregation of power purchasing on behalf of a jurisdiction's electric consumers. A large and growing number of consumers in Massachusetts obtain their power supply from Municipal Aggregations, which offer greater price stability and increased use of renewable resources. Green Energy Consumers has documented the financial and environmental superiority of aggregation over Basic Service and so we

greenenergyconsumers.org
Boston: 284 Amory Street, Boston, MA 02130 | Phone: 800-287-3950
Providence: 188 Valley St, Suite 221, Providence, RI 02909 | Phone: 401-861-6111

believe that grid modernization policy should be designed to enhance, not detract, from aggregation. We see excellent synergies between aggregation and grid modernization.

Transportation:
We agree with the Barr Foundation's comment with respect to 8.2 that the outline should explicitly cover medium- and heavy-duty vehicles, especially transit buses and school buses.

Regarding 9.1.2, the outline now reads, ": Electric vehicle charging demand management scenarios and associated preliminary incentive designs (discussion of both $/kW incentives to attract participation and ongoing c/kWh incentives to subsidize O&M especially in targeted EJ communities)." We disagree with that framing and some of the comments made by EDCs in GMAC meetings. There is obviously a strong rationale to offering $/kW incentives for managed charging. In our view, the values of the per kW and per kWh incentives should be as large as possible for all consumers to incentivize rapid and large-scale adoption without causing a cross-subsidy from non-EV owners to EV owners. An incentive per kWh to charge off-peak should not be automatically assumed to be a cross-subsidy if it is calibrated to reflect a lower cost of service.

We submitted testimony on this issue in dockets 21-90 and 21-91 and can provide further information upon request. To be clear about the need for per kWh incentives, Green Energy Consumers does not believe that it is wise to depend upon MOR-EV purchase rebates as the primary tool for encouraging EV adoption. Funding for MOR-EV will never be sufficient and it should be targeted to LMI consumers. Furthermore, it is not apparent that the Commonwealth will be able to achieve its economy-wide 2030 greenhouse gas target of 50% unless we surpass the transportation electrification target now in the Clean Energy and Climate Plan. Challenges in the building and electricity sectors should cause us to be more aggressive in transportation.

Buildings:
Section 9.4 references decarbonized gas solutions, listing geothermal, hydrogen, and renewable natural gas. Geothermal should definitely be considered, but that is not a decarbonized gas solution. Geothermal ought to be covered in Section 8.1. More importantly, Green Energy Consumers strongly opposes the mixing of hydrogen and renewable natural gas into the pipeline distribution system. Both of those sources are wildly expensive and have dubious greenhouse gas emission benefits to put it mildly. And hydrogen is unsafe. There are going to be sensible uses of hydrogen in industrial applications but, in those cases, the implications for grid modernization would be very small relative to many other issues to consider in the ESMP.

Granularity and Statewide Coherency:

On one hand, we would continue to see granular projections looking at issues at the local level, rather than just at the EDC level, particularly in areas that show some indication today of reaching critical points with respect to DER adoption or distribution system maintenance. On the other hand, we encourage the EDCs to look for ways to formulate similar policies and programs whenever possible. From the consumer's perspective, we assert that the Balkanization of utility programs impinges on the adoption of energy efficiency and DERs. The Balkanization we have today has made consumer education far more difficult than necessary.

Thank you again for the opportunity to provide feedback. I look forward to discussing the outline and to continued collaboration.

Sincerely,

Larry F Chretien

Larry Chretien, Executive Director

Dear Commissioner Mahony and members of the Grid Modernization Advisory Council,

New Leaf appreciates the opportunity to provide comments on the Electric Sector Modernization Plan ("ESMP") outline provided by the Electric Distribution utilities. The outline contains the major elements as required under last year's Climate Law. New Leaf Energy provides the following additional recommendations to improve the comprehensiveness of the document and the ease of use for stakeholders. We appreciate that much of this may already be in the EDC's more detailed plan for the completion of the ESMPs but nonetheless want to highlight some desired ESMP components from the perspective of a DG Stakeholder.

- **Section 1.0 5-year Electric Sector Modernization Plan Investment Summary**

  We recommend that the EDCs include with the high level summary of investment requests in this section cost estimates and timelines. Full detail of the investment requests with detailed cost estimates and bill impacts should be included in Section 7.0 following explanation of the current state of the Distribution System, compliance with 2022 Climate Act, and forecasting results.

- **Section 4.0 Current State of the Distribution System**

  The EDCs have proposed a description of some critical attributes of each subregion. As one of the drivers of the ESMPs is DER enablement it would be helpful for the EDCs to describe in 4.2.4 DG installed and pending (including ongoing group studies within that planning region) and similar information for EVs. It would be helpful for the EDCs to incorporate in each subsection some key metrics. For example, the EDCs could provide some interconnection queue metrics including installed, pending, and withdrawn requests to capture historic DER interest in that sub-region. As a component of this section or 4.2.5 the EDCs should summarize existing substation transformer and feeder hosting capacity.

- **Section 5.0 5- and 10- Year Electric Demand Forecast**

  New Leaf agrees with the recommendations made by the Coalition for Community Solar Access (CCSA) regarding breaking down the forecast for PV and battery systems separately. Presumably this section may also represent solar and battery projects presently in queue that will be operational within the 5 year period. The EDCs should provide sufficient insight into how the solar and battery growth components were derived and how they correspond with the current interconnection queue.

- **Section 6.0 5- and 10-Year Planning Solutions**

  For each subregional infrastructure project or alternative please include an itemization of benefits. One recommendation to improve the readability of the document is to create a standardized table that identifies the solution or alternative impact on ESMP drivers such as reliability, resiliency, electrification capacity needs, DER enablement with some relevant metrics. This will improve stakeholders' understanding of the tradeoffs for each option and attribute.

We also recommended that for each sub-region the EDC's identity required enabling transmission infrastructure with cost estimates, indication of expected cost recovery process, and estimated implementation timeline for those investments. For transmission infrastructure investments already proposed in Local System Plans, provide the current status and estimated implementation timelines.

- **Section 6.3 Technology Platforms**

The implementation of technology platforms represent critical milestones for the modernization of the grid, the timeline to integrate Distributed Energy Resources, and the optimization of 5, 10, and outer year infrastructure portfolios. New Leaf recommends that the EDCs specifically include a timeline that details the development and full implementation and integration of these platforms within the ESMP.

- **7.0 5-Year Electric Sector Modernization Plan**

We expect that this section is likely to be detailed and will comprise much of the request for approval to the Department of Public Utilities in regards to specific infrastructure upgrades and rate recovery treatment for the initial 5-year period. If this section is intended to identify specific investment requests for Department approval, it should include at a minimum, (1) a detailed description of the investment, including projected cost, equipment, permitting and licensing requirements, and construction timeline, (2) projected bill impacts; (4) any associated proposed tariffs or revised existing tariffs (3) a detailed description of how the investment will benefit ratepayers and aligns with cost-efficiently meeting the Commonwealth's clean energy policies; and (4) explanation of how the investment will affect low-income and environmental justice populations, including describing any projects that will be constructed in an environmental justice neighborhood.

If the EDCs are proposing alternative finance mechanisms in section 7.1.2 to allocate costs to specific types of customers[1] they should include their proposed methodology, any rate calculation formulas and supporting tariffs as applicable.

This section should also identify and describe required enabling transmission infrastructure with cost estimates, indication of expected cost recovery process, and estimated implementation timeline for those investments.

- **8.0 2035-2050 Policy Drivers: Electric Demand Assessment**

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[1] For example interconnection customers receiving service pursuant to the EDC Standards for Interconnection Distributed Generation including simplified, expedited, and standard process customers.

It would be helpful to understand the intention of the offshore wind forecast section and its impact on the ESMP. New Leaf agrees that visibility into current projections for utility-scale resources of all types would be helpful within this document but has a concern that these may quickly stale depending on the outcome of interconnection queue churn, procurements, and legislation and potentially singularly focused on offshore wind. What may be most helpful in this section or Section 9.0 would be the currently projected resource mix and enabling transmission upgrades or bottlenecks, whether identified in the ISO New England 2050 Transmission Study or otherwise, and any outer year investments the EDCs envision they will need related to building, transportation, DER and the timeline they anticipate for those infrastructure investments.

- **Mapping/Visualization**

  The EDCs should incorporate regional or sub regional maps where possible to help stakeholders understand the geospatial impact and relationships between various forecast and plan drivers. The heat maps the EDCs presented at the May 2023 GMAC meeting to visually illustrate their forecast results were beneficial for this purpose. Subregional versions of these could benefit local stakeholders to better understand the relevance of specific forecasts or proposed infrastructure upgrades.

I would be happy to answer any questions or expand upon any of these recommendations at our next GMAC meeting and look forward to continued collaboration.

Yours Sincerely,

Kathryn Cox-Arslan

Director, Transmission Policy & Strategy
New Leaf Energy
kcoxarslan@newleafenergy.com
617-510-3360

June 28, 2023

Dear Commissioner Mahony and Members of the Grid Modernization Advisory Council,

Thank you for the opportunity to review and provide comments on the draft EDC ESMP outline and the prioritization by the GMAC, DOER, and EDCs of stakeholder feedback in the development of plans that are integral to the decarbonization of the Commonwealth's electric grid. On behalf of the Solar Energy Business Association of New England ("SEBANE") and our 86 member companies, we offer the following comment related to the Electric Sector Modernization Plan outline.

The ESMPs require clarity in the area of cost recovery including how costs may be allocated to solar customers as one of many potential funding mechanisms. SEBANE requests the EDCs distinguish in Section 7.0 any specific cost recovery treatment related to DER and establish a consensus-based methodology and fee structure in the ESMP. This would include EDC proposals for system modification cost recovery for simplified, expedited, and standard project sizes and a proposed tariff for implementation.

In past DPU proceedings SEBANE and other stakeholders have identified the need to solidify cost allocation mechanisms so that interconnecting customers can pay an appropriate share for infrastructure upgrades as one of the many beneficiaries and users of the electric grid. SEBANE and industry members have previously vocalized support for some form of common system modification fee to contribute to upgrade costs for secondary transformers and circuit upgrades that would allow entire neighborhoods to electrify[1]. Resolving this challenge is a significant opportunity area for the 5-year ESMP. As the GMAC may be aware interconnection costs can be prohibitive for solar projects across the Commonwealth. The Provisional Program and Capital Improvement Projects proposed by National Grid and Eversource have partly addressed how to enable capacity for rooftop solar but not how its paid for affordably. The majority of pending Capital Improvement Projects fees approach or exceed $500/kW-AC which can potentially be applied to any project greater than 15kW[2]. This presents a challenge for solar installation across the state, especially in the built environment where these $/kW fees and needed upgrades are a signal of areas where residential and commercial solar installation may not be possible. The EDCs should include in Section 7.0 the entirety of their proposed ratemaking treatment and fees for all customer types.

Please contact us if you have any questions or if SEBANE can be of any assistance to the GMAC.

Sincerely,
Nick D'Arbeloff
Solar Energy Business Association of New England

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[1] *In addition to comments provided in MA DPU 20-75 the EDCs and GMAC can consider the pending reform in Connecticut in docket 22-06-29 in addition to activities in New York, California, and Minnesota as they consider cost allocation treatment for small system sizes.*
[2] From CIP Tariff: "*any Interconnecting Customer whose DG Facility, regardless of facility type or installation location, is located in the CIP Area and is greater than 15 kW on a single-phase circuit or 25 kW on a three-phase circuit. A CIP Fee Customer will be assessed a CIP Fee."*

SEBANE
Solar Energy Business Association of New England

THE COMMONWEALTH OF MASSACHUSETTS
OFFICE OF THE ATTORNEY GENERAL
ONE ASHBURTON PLACE
BOSTON, MASSACHUSETTS 02108

ANDREA JOY CAMPBELL
ATTORNEY GENERAL

(617) 727-2200
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June 29, 2023

Re: ***Grid Modernization Advisory Council***

In addition to the comments offered during the June 15, 2023 Grid Modernization Advisory Council ("GMAC") Meeting, the Office of the Attorney General ("AGO") submits the following written comments in response to the Electric Sector Modernization Plan ("ESMP") outline proposed by the electric distribution companies ("EDCs"). The following comments are not meant to be exhaustive, nor do they include every issue that the AGO may address now or in the future in connection with the development of the ESMPs.

<u>Stakeholder Outreach and Engagement</u>

Section 3: During the June GMAC meeting, the EDCs acknowledged that this type of effort to engage stakeholders is new to the EDCs. The ESMPs should include a discussion of how the EDCs will ensure that they are utilizing best practices with regards to engaging stakeholders (*e.g.*, by hiring professionals or experts in stakeholder outreach, rather than tasking non-experts with trying their best). Sub-section 3.4 or 3.5 should also include a discussion on how the EDCs will explain the specific ways that input from stakeholders affected their filing (or why it did not). This could be referenced in Section 3 and then a full discussion of the input received and what the EDCs did with that input could be attached as an Appendix.

Section 4: For 4.2.8 (siting and permitting), the EDCs should discuss how they will engage local community-based groups and residents of potentially impacted communities (to ensure that proposals are informed by local knowledge and an understanding of perceptions of localized impacts) and how they will make sure that they employ best practices.

<u>Demand-Side Management ("DSM")</u>

Sections 6, 8, 9: The outline should more proactively address how the EDCs plan to use DER and other demand side management strategies to forestall and reduce capital spending. While there are some references to DSM (*e.g.*, Section 6.5.2 Non-Wires Alternatives; Section 8.1.4 Demand Response Scenarios), this critical component of electric distribution planning is not a central focus, nor is it emphasized at any point in the outline. DSM should be discussed in the 5 and 10 year planning horizon (Section 6, 5- and 10-year Planning Solutions) as well as in the longer term horizon (Sections 8 and 9 cover 2035-2050). In connection with managed charging specifically, research indicates that transportation electrification with unmanaged charging will be significantly more expensive than with managed charging. State, federal, and private investment in EVs and EV charging infrastructure will be significant in the near-term horizon and EV adoption is expected to increase; waiting until 2035 to actively pursue managed charging may lead to unnecessary and costly grid investments. Incentivizing peak demand reduction in the near term should be a priority.

Cost Concerns

The statute makes clear that the GMAC should encourage "least-cost investment" in the ESMP and also should "maximize net customer benefits and demonstrate cost-effective investments …". G.L. c. 164, §92C(b). In order to facilitate the GMAC's work on this front, the ESMP outline should include a discussion of costs, rate impacts and customer benefits. The ESMP should also identify where the EDCs believe it is necessary to seek approval for additional investments beyond those investments that have already been approved, what the costs are for those additional investments, and why the EDCs believe those costs should be treated as "incremental."

Transmission System Investments

G.L. c. 164, §92B(a) states: "The department shall direct each electric company to develop an electric-sector modernization plan to proactively upgrade the distribution and, where applicable, transmission systems…" The statute additionally directs the following: "An electric-sector modernization plan developed pursuant to subsection (a) shall describe in detail each of the following elements: (vi) improvements to the transmission or distribution system to facilitate achievement of the statewide greenhouse gas emissions limits under chapter 21N." G.L. c. 164, §92B(b)(vi).

The statute clearly contemplates transmission as an overall part of the ESMPs. The EDCs' outline does not include transmission system upgrades. At minimum, the ESMPs should include information about any transmission upgrades that may be triggered by or may be needed to support the ESMP-related distribution system upgrades. The inclusion of transmission is critical for stakeholders to be able to understand the full scope of the investments proposed as part of the ESMPs.

Sincerely,

/s/ Elizabeth A. Anderson

Elizabeth A. Anderson
Assistant Attorney General
GMAC Member

July 13, 2023 GMAC Meeting Public Comments

Written Comments Submitted in Advance to MA-GMAC@mass.gov

Submitted Comments

1. Greg Hunt, ZPE Energy (ghunt@zpeenergy.com) - Received 7/12/23
2. Rich Creegan, Anterix - Received 7/12/13

1. **Greg Hunt, ZPE Energy (ghunt@zpeenergy.com) - Received 7/12/23**

Regarding:

- Overly Impacted and Rarely Heard. Stakeholder Working Group convened by the Attorney General's Office. May 2023.
- Fostering Equity through Community-Led Clean Energy Strategies.
- EDCs' ESMP

The Overly Impacted and Rarely Heard Stakeholder Working Group report was great to read. Clearly a lot of work and effort to put together a very robust document. Thank you.

My only comment is, that how something is measured drives how it gets done, and results should be visible. In order to get stakeholder input from communities that don't normally have a voice there needs to be a clear showing that not only can they participate meaningfully, but that their input can actually have an impact.

My comment is that a reporting requirement be included for each of the above that contains the following ideas.

- What was the initial plan.
- What very specifically was changed as a result of feedback from that community, in great detail.
- What very specific feedback resulted in the change.
- Specifically who the feedback came from that resulted in a change.

July 13, 2023

Via email to <MA-GMAC@mass.gov>

The Honorable Commissioner Elizabeth Mahony
Grid Modernization Advisory Council Chair
Department of Energy Resources
100 Cambridge Street
Suite 1020
Boston, MA 02114

Re: Comments of Anterix

Dear Chair Mahony:

Anterix, a utility solutions developer enabling private, secure wireless broadband to power the evolution of our Nation's grid in support of the integration of distributed energy resources, enhanced cyber and physical security, greater resilience, and energy equity, respectfully submits the following comments in response to the invitation for public comment posted on the Grid Modernization Advisory Council's (GMAC) website.

Created by the team that founded Nextel and brought push-to-talk communications to the utility industry, Anterix provides foundational spectrum that enables risk mitigation and meets the evolving business needs of electric utilities. The premise of our offering to the utility sector is that "a modern grid requires modern communications." As explained in these comments, utility-controlled, private wireless broadband networks such as those enabled by Anterix are critical to meeting the challenge described in Sec. 53 of "An Act Driving Clean Energy and Offshore Wind" (the "Act"), which created the GMAC.

In its efforts to address climate change while ensuring reliability, the Commonwealth has established greenhouse gas emissions limits and required "electric-sector modernization plans" (ESMPs) to "proactively upgrade the distribution and, where applicable, transmission systems." To meet those emissions limits, the grid will need to accommodate broad electrification of multiple sectors of the economy, and the massive integration of renewable distributed energy resources (DERs) and energy storage, as acknowledged in the Act. But tellingly, in the Act's list of six key ESMP purposes, the first is that the ESMP proactive upgrades must be to "improve grid reliability, communications and resiliency." That makes sense: electrification and a shift to DERs—indeed, adequately serving the electric customer of the future—cannot succeed without grid reliability, communications, and resiliency. And of those three, communications is the foundation. The modern grid, with two-way energy flow and massive DER integration, requires modern communications capabilities to operate safely, efficiently, and reliably.

Realizing the Act's vision of a "distribution grid that enable[s] interconnection of, and communication with, distributed energy resources and transmission-scale renewable energy resources" will require advanced communications networks that have coverage to all corners of the

Commonwealth with the ability to: 1) monitor the data from all energy utilities, including consumer resources behind the meter; and 2) manage certain loads, storage and dispatchable generation. The ability to monitor the grid will provide the insight and the ability required to manage resources to optimize grid operations. Anterix believes that a private, non-proprietary LTE network is the best way to ensure security and avoid proprietary network restrictions. Once a secure advanced communications network is supporting grid operations, it will provide the flexibility to adjust priorities and operations to meet potential emergencies or long-term goals. Just like we have experienced in our daily lives as citizens, employees, and consumers, a utility-focused broadband network will become a platform for innovation. Anterix has created a utility solutions ecosystem involving more than 100 of the Nation's leading technology and service companies to enable such an innovative future.

Optimization of tomorrow's grid will require a much higher level of system awareness and the ability to productively modify resource behavior. Utilities must be able to invest in a communications network that is "utility-grade" so it is up and running during a disaster, supporting the power recovery efforts that are the backbone of grid resiliency, including mutual aid. They and their customers require a network with extremely low latency so a utility can monitor and react to disturbances before they create problems—as in the cases of voltage regulation or the line galloping that can occur during a storm. Above all, utilities need to be able to invest in secure private networks separate and apart from the public internet as delineated in the number one recommendation of the President's National Infrastructure Advisory Council.[1]

Historically, utility telecom networks were purpose-built, relying upon existing narrowband technologies and resources. Now, many of those networks are aging out and are in need of replacement as commercial carriers abandon 3G service or are using increasingly congested unlicensed spectrum. Running fiber to every grid device beyond utility substations is not a viable option for utilities. Investment in private wireless broadband networks—a new option made generally available to utilities only a few years ago—offers the robust, secure connectivity needed to fulfill the twin goals of insight and optimization, both of which provide customer benefits in the form of reliable, cost-effective electric service. Five utilities that provide service across 14 states, have already begun the process of deploying a private wireless broadband network.

Spectrum—the radio waves that wireless networks use to carry communications signals—is the foundation of private wireless broadband networks for critical grid communications, and thus also the foundation upon which grid modernization technologies depend. As the primary holder of licenses for broadband-capable spectrum in the 900 MHz band across the country, Anterix understands how access to the right spectrum empowers the modernization of critical infrastructure by enabling private broadband connectivity. Its foundational spectrum enables risk mitigation and meets evolving business needs of electric utilities, with greater cybersecurity, resiliency, and control. These comments, including the document attached hereto and incorporated by reference (Enhancing Utility Connectivity Through Secure Wireless Broadband Networks), expand our description of the importance of wireless broadband networks to the future of Massachusetts utilities and their customers.

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[1] In its August 2017 report, the President's National Infrastructure Advisory Council recommended the Administration "Establish SEPARATE, SECURE COMMUNICATIONS NETWORKS specifically designated for the most critical cyber networks" (emphasis in original). It went on to state, "Industrial control systems connected to business IT systems and the Internet constitute a systemic cyber risk among critical infrastructure." (*Available at* <https://www.hsdl.org/?abstract&did=803545>).

As the GMAC considers the technology future of the Commonwealth's grid, Anterix respectfully requests that the need for private wireless broadband communications networks as a foundational element be part of that consideration.

Respectfully submitted,

Richard S Creegan

Richard Creegan
Senior Vice President, Utility Partner Engagement

Attachment

Anterix, "Enhancing Utility Connectivity Through Secure Wireless Broadband Networks"

Anterix™

Enhancing Utility Connectivity Through Secure Wireless Broadband Networks.

For a utility looking to modernize its grid, "A modern grid requires modern communications" is a good starting premise. Beyond that, a modern communications platform unlocks numerous additional opportunities to address a wide range of issues facing today's utilities.

DER Integration:

The decarbonization driven proliferation of renewable energy generation resources is changing the paradigm for electric utilities. A home with a rooftop solar installation, for example, exhibits a kind of "prosumer" (producer-consumer) behavior. To safely and efficiently integrate DERs into the grid—whether they be owned by the utility or a third party—utility operators must have greatly improved grid visibility, control, and automation capabilities. The sensors, smart devices and applications that will provide utilities these enhanced capabilities depend upon connectivity via a private broadband data network.

Cyber & Physical Security:

With the greater reliance upon data for grid control—and with cyber attackers growing more sophisticated, security of any new data communications network is of critical importance. LTE offers a particularly robust, up-to-date set of security features. LTE provides more granular control of the network and the connections between discrete network elements. In a private deployment, the utility has the control to implement any or all of LTE's advanced, optional security features, as well as any additional utility specific cyber or physical security management functionalities.

EVs/VPPs:

When they are being charged (grid-to-vehicle, or G2V), electric vehicles (EVs) represent load to the utility; when their batteries are used as storage for power that can be supplied back into the grid (V2G), they are stored power distributed energy resources (DERs) for the utility. EV charging data would be useful to utilities that want to manage charging times in order to mitigate peak load conditions. Looking further into the future, utilities could treat EVs like any other DER, relying upon secure broadband connectivity to manage the time and amount of V2G power the EV provides. And with appropriate communications, a utility could even establish a virtual power plant from a multitude of EVs, saving the cost and environmental impact of firing up a peaking power plant to meet short-term spikes.

Wildfire Mitigation:

To reduce the threat of wildfires and other risks of having downed wires, utilities are planning to deploy a technology from Schweitzer Engineering Laboratories (SEL) called Falling Conductor Protection (FCP) that, when enabled by a low-latency, high-bandwidth broadband network, can identify a power line when it breaks and, as it falls, cut its power before it hits the ground.

SCAN ME

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SECURITY
Maximum cyber security protection

RESILIENCY
Real-time visibility to support a proactive posture, quick response time, and ability to meet capacity demands

OPERATIONAL IMPROVEMENTS
Accessible data exchanged in real-time (without going into the field)

CLEAN ENERGY TARGETS
Support and proactively advance strategic electrification efforts

CUSTOMER IMPROVEMENT
Predict and prevent public safety threats, improve utility security and enable smart city technologies

900 MHz Private LTE is the Foundation for the Future

A communications infrastructure built on utility-grade 900 MHz Private LTE is a smart, long-term solution that enables utilities to achieve their goals—STARTING NOW.

ANTERIX ACTIVE ECOSYSTEM AND ANTERIX SECURITY COLLECTIVE:

The Anterix Active Ecosystem brings one hundred leading technology companies together that are supporting 900 MHz Private LTE (PLTE) networks and shaping the future of private wireless broadband. Members enjoy technical assistance, collaborative tools and marketing support to develop products and services for 900 MHz PLTE networks enabling utilities and the critical infrastructure sector.

Anterix formed the seven-member Security Collective within the Anterix Active Ecosystem Program, to assemble cyber-physical solutions providers to deliver sector-specific knowledge and collaborations. Each Anterix Security Collective member is committed to collaborating with utilities and within the Collective to contribute to the broader effort of finding and implementing comprehensive solutions.

Cape Light Compact

Cape Light Compact JPE
261 Whites Path, Unit 4, South Yarmouth, MA 02664
Energy Efficiency 1.800.797.6699 | Power Supply 1.800.381.9192
Fax: 774.330.3018 | capelightcompact.org

July 13, 2023

Re: Comments on Electric Sector Modernization Plan Draft Proposed Structure

Dear Commissioner Mahony and Grid Modernization Advisory Council Members,

The towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Edgartown, Eastham, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, West Tisbury, Wellfleet and Yarmouth, and Dukes County, organized and operating collectively as the Cape Light Compact JPE, a joint powers entity pursuant to G.L. c. 40, §4A ½ and G.L. c. 164, §134 (the "Compact"), have the following comments on the Draft Proposed Structure for the Electric Sector Modernization Plan ("ESMP") submitted by the electric distribution companies ("EDCs"):

1. The ESMPs should fully account for overlap and/or duplication with energy efficiency, and should define the roles of the following in the ESMPs:
   a. Energy Efficiency Advisory Council;
   b. Energy Efficiency Program Administrators and recognition of the statewide MassSave® brand;
   c. Massachusetts Clean Energy Center and the Clean Energy Lives Here™; and
   d. Clean Energy Transmission Working Group.

2. Section 6: The Compact supports the June 29, 2023 comments on data access by the Department of Energy Resources ("DOER"), and agrees that the EDCs should include "a description of what a uniform statewide data access strategy and process might look like for the Commonwealth." (at 2) The work of the AMI Stakeholder Group, including on data access and time-varying rates ("TVR"), should be described in the ESMP. (A description of progress by all relevant working groups should be included in the ESMPs.)

3. Section 13.2 contains the "[p]rocess to support updates to the ESMP throughout the 5-year cycle." This section is crucial given, among other things, pending Department of Public Utility (the "Department" or "DPU") dockets (e.g., D.P.U. 22-51 through 22-55), the upcoming energy efficiency Three-Year Plans, and resolution of existing working groups (e.g., AMI Stakeholder Group will submit its final report in August 2024). The capital improvement projects ("CIP") dockets (D.P.U. 22-51 through 22-55) seek to resolve significant barriers to distributed generation interconnection in certain saturated areas of the Commonwealth. In particular, the Cape CIP in D.P.U. 22-55, where a DPU order is pending, was challenged in a way that could result in those interconnection barriers not being resolved. See D.P.U. 22-55, Compact Initial Brief at 9 (Section B) (March 9, 2023). The EDCs should have a mechanism in the ESMP that would allow them to propose investments in such situations that are currently unknown but essential for clean energy goals.

4. Section 13.3: "Reporting and Metrics" should be a category of its own outside of the Conclusion in Section 13. Metrics and reporting will be critical to meeting clean energy goals. This section should include existing metrics, as well as note when and how future metrics are to be considered. For example, if TVR metrics are not adopted in D.P.U. 21-80, it should be noted in the ESMP when and how they will be considered. See D.P.U. 21-80, Compact Comments at 6-7 (May 3, 2023). The Compact raised the need for comprehensive and coordinated reporting across all of an EDC's activities and dockets (e.g., performance-based ratemaking, energy efficiency, grid modernization, advanced metering, electric vehicles, provisional system planning) on such crucial measurements as peak demand reductions, without which it will be impossible to effectively gauge whether the Commonwealth is truly moving towards its clean energy goals. D.P.U. 21-80, Compact Final Comments at 5 (May 24, 2023).

5. Section 1.0 or 2.0: The ESMP should clearly describe the Grid Modernization Advisory Council roles and responsibilities set forth in An Act Driving Clean Energy and Offshore Wind (2022), including to review and provide recommendations on the ESMPs according to the enumerated criteria.

The Compact appreciates the opportunity to provide feedback.

Submitted by:

Margaret T. Downey

Margaret T. Downey, Administrator

August 10, 2023 GMAC Meeting Public Comments

Written Comments Submitted in Advance to MA-GMAC@mass.gov

Submitted Comments

1. Heather Deese, Senior Director of Policy & Regulatory Affairs for Dandelion Energy (hdeese@dandelionenergy.com) - Received 8/11/23

DANDELION

August 10, 2023

Commissioner Elizabeth Mahony
Department of Energy Resources
Chairperson
Grid Modernization Advisory Committee
100 Cambridge Street
9th Floor
Boston, MA 02114

Subject: Dandelion Energy Comments to the Grid Modernization Advisory Council

Thank you for the opportunity to provide comments to inform the work of the Grid Modernization Advisory Council (GMAC). Dandelion is the nation's leading installer of home geothermal heating and cooling. We are a team of 250 people, two-thirds of whom are in the field everyday installing geothermal ground loops and heat pumps for our customers in New York, Connecticut, and Massachusetts.

Geothermal (ground source) heat pumps use a buried closed loop of fluid-filled plastic piping to move heat from the ground into a home during the winter, and move heat from the home into the ground in the summer to provide air conditioning. Ground Source heat pumps provide key climate and efficiency benefits:

- They decrease energy usage for space conditioning in a typical home by 75-80%; and

- They also meet the full heating needs of buildings, even in the coldest climates; so there is no need for dual fuel systems. The ground loop is designed to provide all of the thermal energy needed.

In terms of this Council's charge to advise on the future of the Commonwealth's electric grid, ground source heat pumps can provide multiple benefits in electrifying the building sector with minimal impact on the grid. As a result of accessing the ground as a heat source and sink, geothermal heat pumps are about two times as efficient, and use about half the electricity, as an air source heat pump system on an annual basis. Geothermal heat pumps will also draw a peak load of only one quarter to one third of an air source heat pump system on the coldest winter days.

For example, for a retrofit using a central heat pump for a typical home in Bedford, MA:

- Ground source requires 8,000 kWh/year compared to 18,000 kWh/year for air source, saving 10,000 kWh/year;
- Ground source has a peak load of 3.7 kW compared to 12.7 kW for air source, a decreasing peak usage by 9 kW;

In other words, for every 1,000 homes that have ground source instead of air source heat pumps, that's a 9MW of peak load savings.

Table 1: Heat Pump Load Comparisons, Bedford MA, 2,500 sq ft				
	GSHP	**High Efficiency Central ASHP (HSPF-9)**	**GSHP % of ASHP**	**GSHP Savings**
Peak electric demand	3.69 kW	12.65 Kw	29%	8.96 kW
Annual electricity use	8,262 kWh	18,345 kWh	45%	10,082 kWh
Annual operating cost	$2,313	$5,136	45%	$2,823

Because they increase electric demand without meaningfully increasing peaks or requiring new electric grid infrastructure, ground source heat pumps allow utilities to spread costs and reduce electricity rates for all rate-payers. In New York, these grid benefits have been assessed at $7,000 that accrues to all other rate-payers from each residential system that is installed.[1]

These grid benefits have been analyzed and reported by respected independent experts. For example, RMI released a report earlier this year that found that "geothermal heat pumps use about 80 percent less energy annually than industry-standard fossil fuel furnaces to heat homes in the Midwest. They use four times less electricity on the most extreme cold days than air-source heat pumps and can support limiting peak demand on the utility system during cold snaps or heat waves."[2]

[1] *New Efficiency: New York, Analysis of Residential Heat Pump Potential and Economics*, NYSERDA, January 2019, p., S-3, https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/PPSER/NYSERDA/18-44-HeatPump.pdf

[2] Clean Energy 101: Geothermal Heat Pumps, RMI, March 29, 2023, accessed August 10, 2023, https://rmi.org/clean-energy-101-geothermal-heat-pumps/

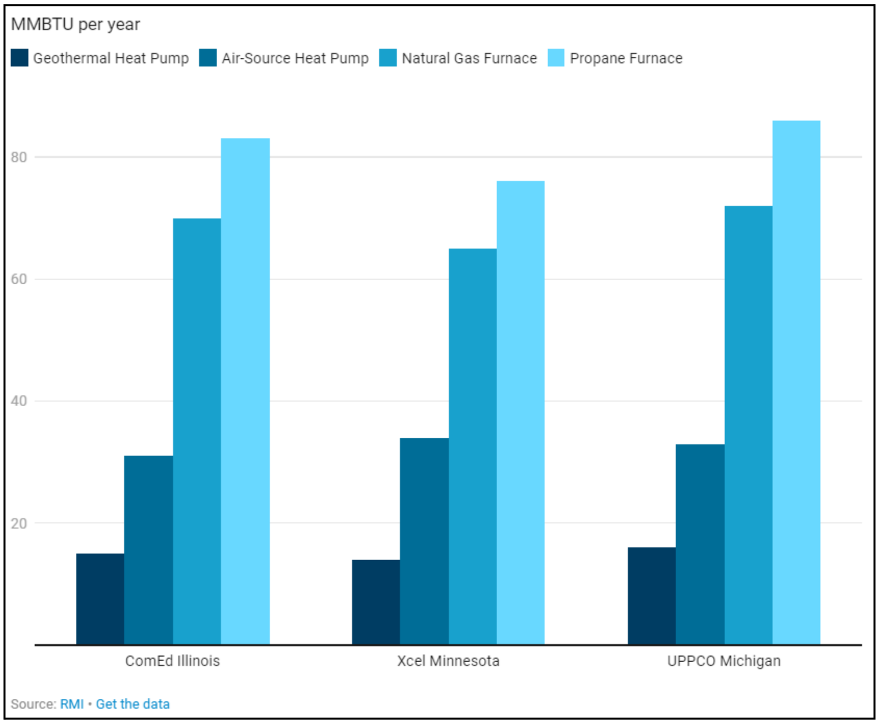

Figure 1: RMI Analysis of Heat Pump Annual Energy Demand

Similarly, a Brattle Group study for Rhode Island found that fully electrifying New England using geothermal heat pumps would only minimally impact peak demand and leave energy prices unchanged. This is in contrast to full electrification using air source heat pumps, which would increase peak demand by 94% and lead to "materially higher electricity prices".[3]

Given these benefits, geothermal heating and cooling should play a major role in beneficial electrification for Massachusetts in order to minimize the total generation capacity needed in the future. Multiple studies have shown that one in every four heat pumps installed should be geothermal to help minimize grid infrastructure costs.[4] The Massachusetts Department of Environmental Protection (MassDEP) highlights that the Commonwealth will require approximately 100,000 residential heat pump installations

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[3] Heating Sector Transformation in Rhode Island: Pathways to Decarbonization by 2050, The Brattle Group, p. 30-31, https://energy.ri.gov/sites/g/files/xkgbur741/files/documents/HST/RI-HST-Final-Pathways-Report-5-27-20.pdf

[4] The Brattle Group study for Rhode Island modeled 33% of heat pumps as geothermal in their mixed-fuel scenario analysis. The New York Climate Action Council Scoping Plan modeled 22-23% of heat pumps as geothermal heat pumps (see Scoping Plan, Appendix G: Integration Analysis Technical Supplement, Annex 2: Key Drivers and Outputs, December 2021, https://climate.ny.gov/resources/scoping-plan/) and the 2019 Department of Energy GeoVision analysis identified market potential for 28 million geothermal heat pumps installed by 2050 (see https://www.energy.gov/eere/geothermal/geovision).

per year to meet its emissions reduction targets[5] — 25,000 of those should therefore be geothermal heat pumps to help optimize for grid investments and energy efficiency savings.

We encourage the Council to work with the electric distribution companies on incorporating a significant percentage of ground source heat pumps into their 5- and 10-year forecasts and into their assessments of demand through 2050. Thank you for the opportunity to engage with the important work of the GMAC.

Respectfully submitted,

Heather E. Deese
Senior Director, Policy and Regulatory Affairs
Dandelion Energy

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[5] Clean Heat Standard Program Design, MassDEP, March 2023, p. 4, https://www.mass.gov/doc/clean-heat-standard-discussion-document/download

The Commonwealth of Massachusetts
Executive Office of Energy and Environmental Affairs
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August 14, 2023

Commissioner Elizabeth Mahony
Department of Energy Resources
Executive Office of Energy and Environmental Affairs

Re: Grid Modernization Advisory Council - Equity and Environmental Justice

Dear Commissioner, Mahony:

The Environmental Justice Office under the Executive Office of Energy and Environmental Affairs appreciates the opportunity to submit comments to the Grid Modernization Advisory Council regarding equity implications of investor-owned electric distribution companies and their electric-sector modernization plans (ESMPs).

Environmental justice is about people; it is about residents who have historically been marginalized and excluded from public processes. It is also about the disproportionate burdens and harms some communities have had to shoulder. The environmental justice movement in the United States was born out of the civil rights movement, as a response to deeply seeded inequities. While we have made incredible progress when it comes to civil rights, the ramifications of racism and classism are still felt and lived by many. The essence of the environmental justice movement is about undoing the harms and reversing decades of both environmental racism and classism. In Massachusetts an "Environmental Justice population" is defined as a neighborhood where one or more of the following criteria are true:

- the annual income is 65% or less than statewide median income
- minorities make up 40% or more of the population
- 25% or more of the households speak English less than "very well"
- minorities make up 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income.

When implementing environmental justice policies, outcomes are as important as processes. One of the main principles of environmental justice is that residents who have historically been excluded and marginalized should have a seat at the decision-making table. EJ populations should be engaged in public processes from the very beginning, not as an after-thought, and the engagement must be coupled with meaningful outcomes and results. Adding equity or community outreach as a final step in the process does not allow for a meaningful process. Successful community outreach happens when the voices and perspective of those most vulnerable are reflected in the outcome.

Below is a non-exhaustive list of best practices for community engagement:

- All neighborhoods who might be impacted by a project should be engaged. Community meetings should be held in the neighborhoods where the project will be located or impacted. They should take place in community friendly locations, ones that are commonly used for community events. They should also be scheduled during different times of day, considering residents living in environmental justice neighborhoods may be working more two to three jobs to make ends meet and don't have a typical 9AM-5PM schedule. Whenever possible community meetings should be scheduled during late afternoon/evening hours and/or weekends.

- Written materials and presentations should not include acronyms. Any technical language should be written and spoken in a way so that residents who do not work in the field of energy generation, transmission or distribution can easily understand.

- All materials, including notices, slides, handouts should be translated (written form) into the languages spoken in the neighborhoods. All meetings should also provide simultaneous interpretation (verbal form) into the languages spoken in the neighborhoods where the project is being proposed and where the meeting is taking place. Multilingual staff whose primary job is not translation/interpretation should not be asked to translate/interpret unless they are certified translators/interpreters and are compensated accordingly.

- Outreach should include notices and flyers publicized in commonly used medium including local newspapers (including multilingual newspapers), social media, local TV channels, churches, senior centers, schools, community centers and other community organizations and gathering spaces.

- Community meetings should also include the following logistical arrangements to ensure robust participation: food, childcare, transportation, and virtual options. Community meetings should include dinner, lunch, or snacks. Providing childcare allows for working parents or grandparents to attend community meetings with their children. Not providing childcare assumes residents have someone at home to watch for their kids, or the resources to hire a childcare provider. Transportation is also a key barrier to ensuring participation. Community meetings should take place near public transit stops so that transit riders can attend. The cost of public transit should also be covered, otherwise those who do not own a car will need to spend money out of their pocket to pay for a bus/train ride in order to participate. Finally, community meetings should be in person with a virtual option. Remote-only meetings present many barriers for residents with limited internet or electronic devices. In-person meetings are recommended, with a virtual option for those residents living with disabilities or who are immunocompromised.

In addition to engaging EJ communities in a meaningful way, below are some key pillars that address inequities that environmental justice populations face in the energy sector.

<u>Affordability</u>

In ensuring a just transition, affordability is a key. Energy burden is defined as the ratio between energy cost and household income. According to the Department of Energy, the national average for energy burden is 3%. In Massachusetts, low-income residents pay an average of 10% of their household income on energy bills. In some neighborhood, the burden is as high as 30%. To ensure a just transition, we must protect low-income residents and people of color from carrying an inequitable energy burden.

Workforce Development

As the clean energy economy grows, electric distribution companies should ensure their workforce is inclusive of Black, Brown, Immigrant, Indigenous and low-income residents. As we grow the workforce needed to electrify the grid, EJ populations must have access to good paying and stable jobs. This includes creating a permanent pathway for residents who currently work in fossil fuel industries so they can transition to new clean energy jobs, as well as a pathway for the younger generations and those who have historically not had access to energy sector jobs.

Cumulative Impact Analyses and Community Benefit Agreements

As we modernize the grid and transition to 100% clean energy, we will need additional infrastructure. Where and how we build and site the infrastructure will have significant implications. Cumulative Impact Analyses are clear way to understand which communities, neighborhoods or block groups already carry a disproportionate burden. When planning for new energy infrastructure or enhancement of existing ones, we must ensure we are not causing additional harm to those who have historically been overburdened. When possible and if feasible, if a project may cause additional harm or burden on EJ populations, an alternative site should be identified.

A just transition includes a proactive approach to mitigating harm on communities who already carry a disproportion cumulative burden. Developing community benefit agreements early in the process and that reflect the needs of a community, are a meaningful way to engage a neighborhood that will host the infrastructures. We will all benefit from a clean and reliable grid, but not every neighborhood is the host to energy infrastructure. We must ensure those neighborhoods living next to energy sector infrastructure see a direct benefit to their community. Community benefit agreements are a great model to follow.

Operationalizing environmental justice can be complex and seem burdensome. However, it is incumbent upon us to ensure that this once-in-a-lifetime opportunity to transition to a clean energy economy is a just and equitable one.

Thank you for the opportunity to comment. Please do not hesitate to contact our office if you have clarifying questions.

Sincerely,

Maria Belen Power.

María Belén Power
Undersecretary of Environmental Justice and Equity
Executive Office of Energy and Environmental Affairs

September 14th GMAC Meeting Written Public Comments

Written Comments Submitted to MA-GMAC@mass.gov

Submitted Comments

1. Louise Amyot, Greenfield, MA Resident, (lamyot@yahoo.com) – Received 9/08/23.
2. Craig Martin, Shutesbury, MA Resident, (thompsonmartinfamily@gmail.com) – Received 9/13/23.
3. Graham Turk, Massachusetts Institute of Technology graduate student, (gturk@mit.edu) – Received 9/14/23.

1. **Louise Amyot, Greenfield, MA Resident, (lamyot@yahoo.com) – Received 9/08/23.**

I am thrilled to know that our electric utilities are planning to update their capacity to service the public with adequate means of providing the growing sources of clean energy that we will need in the coming years.

In the face of the terrible storms and weather crises that we have been experiencing all over the planet, I write to say that I hope that you are all considering expanding this infrastructure ***underground***. Whether facing flooding, hurricanes, fires, drought or even insect infestations, having utilities provided by underground cable will ensure that a) power will not be lost and b) wires will not be causing fires anywhere. Beyond the energy and environmental benefits of such a move, the savings in repairs and lawsuits to the electric companies will add up to enormous savings down the road. I imagine that your companies have already considered underground transmission lines; I simply want to encourage you to follow through with this seriously important move.

Thank you,

Louise Amyot

56 Madison Circle

Greenfield, MA 01301

2. **Craig Martin, Shutesbury, MA Resident, (thompsonmartinfamily@gmail.com) – Received 9/13/23.**

I would like to add my support to the Commonwealth's efforts to modernize the distribution of electric power. As we move more towards replacing fossil fuels with renewably generated electricity, efficiency, reliability, and the economics of distribution will continue to be critical issues. I urge our leadership to work with, but not be driven by, the current electricity providers. I also urge our leaders to not be constrained by small minorities who resist things like smart meters. Granting an opt out to a small class of poorly informed citizenry will inevitably reduce efficiencies, impacting the much larger group of citizens who embrace progress.

Sincerely,

Craig Martin

Shutesbury, MA

3. **Graham Turk, Massachusetts Institute of Technology graduate student**

I am an Eversource customer and graduate student at MIT doing research on the grid impacts of EV charging.

In Eversource's 568-page plan, they dedicate 0 pages to redesigning rates that would mitigate or defer the need for distribution and transmission system upgrades and investments in capital-intensive battery storage. There is ample evidence (which I can send if helpful) that if price incentives exist, EV and heat pump customers will shift their load in a way that reduces aggregate peak demand. Eversource conducted their load forecasts under the assumption of flat volumetric rates, which yields an inflated estimate for capacity needed to support electrification. They also ignored the possibility of demand response as a firm capacity resource, which contradicts programs currently offered by ISO New England.

GMAC should recommend that Eversource conduct sensitivity analyses where alternative rate designs and load control are modeled; capital-intensive upgrades should be used only as a last resort after all other solutions to mitigating peak demand have been exhausted.

October 26th GMAC Meeting Written Public Comments

Written Comments Submitted to MA-GMAC@mass.gov

Submitted Comments

1. Michael Savage, Vice President of Business Development of Vergent Power Solutions, (msavage@vergentpower.com) – Received 10/16/23.
2. Advanced Energy Group's Grid Modernization Task Force, Contact: Sarah Sweeney, Advanced Energy Group Fellow, (sarah.sweeney@goadvancedenergy.com) – Received 10/20/23.

1. **Michael Savage, Vice President of Business Development of Vergent Power Solutions, (msavage@vergentpower.com) – Received 10/16/23.**

1) Eversource has stated its proposed investment to be $6 billion over the next 5 years. With increased load growth what is the expected incremental impact on a kWh basis? My own calculation based on other Eversource grid mod investments reflect an incremental cost of $.10/kWh for the next 5 years. They have then said there will be an additional $6 billion investment for year 6-10.

2) Same question for National Grid. They have proposed to spend $2 billion over the next 5 years. With increased load growth what is the expected incremental impact on a kWh basis?

Advanced Energy Group
23Q3 Grid Modernization Task Force
Friday, October 20, 2023

To the Grid Modernization Advisory Council and the Equity Working Group,

On August 17, 2023, Advanced Energy Group convened 40+ public and private leaders at the AEG Boston Stakeholder Challenge on Grid Modernization to address critical climate, health, and equity challenges for Greater Boston. Stakeholders aligned on a critical obstacle to address in 12-months, developed a solution to this challenge, including a 90-day goal, and 12-month goal, and formed a Task Force of 13 leaders to deploy the solution:

> **Derived 12-Month Critical Obstacle**: "Building trust and understanding with customers and communities by implementing equity and health-based metrics into decision-making processes to enable meaningful collaboration and deliver an electrification-based energy transition equitably and affordably." - Melissa Lavinson, Head of Corporate Affairs, NE, National Grid & Jonathan Buonocore, Assistant Professor, Department of Environmental Health, Boston University
>
> **90-Day Goal:** Improve our understanding of the Utility Electric Sector Modernization Plans (ESMP) and their investments into EJ communities
>
> **12-Month Goal:** File ESMP's with robust Stakeholder Feedback

In working towards the 90-day goal, our Task Force reviewed the ESMPs and developed a draft equity evaluation matrix with guiding questions to serve as the basis of our recommendations related to inclusive decision-making, community impact, equity, and health. To support our electric distribution companies in their commitment to fostering trust, promoting understanding, and advancing equity, these questions include:

1. Do the ESMPs include **plain language** to communicate the impacts and outcomes of the ESMPs?
2. Do the ESMPs include maps and visuals that make it easy for community members to understand the **local impact** of proposed solutions?
3. Do the ESMPs provide and **guarantee opportunities** for **local communities** to engage and provide meaningful input?
4. Do the ESMPs address disparity of wealth and environmental justice in the Commonwealth and provide **measurable relief** in the form of **economic benefits** to communities that have or will be disproportionately impacted?

5. Do the ESMPs address disparity of wealth and environmental justice in the Commonwealth and provide **measurable relief** in the form of **health benefits** to communities that have or will be disproportionately impacted?

As the Equity Working Group considers its recommendations for the Grid Modernization Advisory Council, we wish to specifically highlight some key recommendations and principles for the EWG to consider.

Recommendation: Establish stakeholder engagement requirements within the ESMP process that, at minimum:

- Establish technical advisory resources and funds for communities to have experts they trust chosen by the community who will represent their community interest and serve as their advocate in technical grid infrastructure matters
- Create notification requirements that ensure that communities are notified adequately in advance of infrastructure plans long before regulators are informed
- Create requirements that ensure informational meetings for affected communities are designed to maximize attendance
- Create awareness and intentionally communicate with communities about upcoming electric sector plans early in the process
- Mandate the requirement for language access plans that are representative of the communities impacted
- Create an accountability system for stakeholder engagement that ensures that impacted communities' interests are prioritized
- Can evaluate participation and representation in the process. Are all groups in a community represented in the stakeholder group? How many participated? Third, how meaningful was the stakeholder process?

Recommendation: Articulate commitment to and processes for the advancement of community ownership, control, and collaboration of distributed energy resources (DER):

- Utilities should partner with municipalities and community groups to accelerate the installation of DER, including community microgrids, to best support the adoption of critical resilience infrastructure
- Utility-owned DERs, such as Eversource's Provincetown microgrid, help advance grid resilience, however, the exertion of exclusive distribution rights and failure to proactively plan for hosting capacity or ease interconnection costs creates impediments and bottlenecks for wider adoption of community-owned and controlled DER
- Utilities should create plans for how to collaborate with communities on non-utility-owned DER, including the publication of guides for how to engage with the

utility on DER interconnection, and proactively seek opportunities to encourage collaborative or community-owned and controlled microgrid projects
- Collaboration should advance economic, racial, and environmental equity goals as well as repair previous harms

Recommendation: Guide the utilities to assess and implement equity tools such as the National Energy Screening Project (NESP) Energy Equity and Benefit Cost Analyses Framework.

- Massachusetts, along with an increasing number of states and jurisdictions, is looking to center energy equity as an overarching goal in the clean energy transition. The National Energy Screening Project (NESP), in partnership with Lawrence Berkeley National Laboratory, is developing a Distributional Equity Analysis (DEA) framework as a companion to the Benefit-Cost Analysis laid forth in NESP's National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources (NSPM). We encourage the EDCs and the Commonwealth to learn about and seek ways to standardize the implementation of practices laid forth in both the NSPM and the DEA framework, explained in Chapter 9 of NESP's Methods, Tools and Resources Handbook.

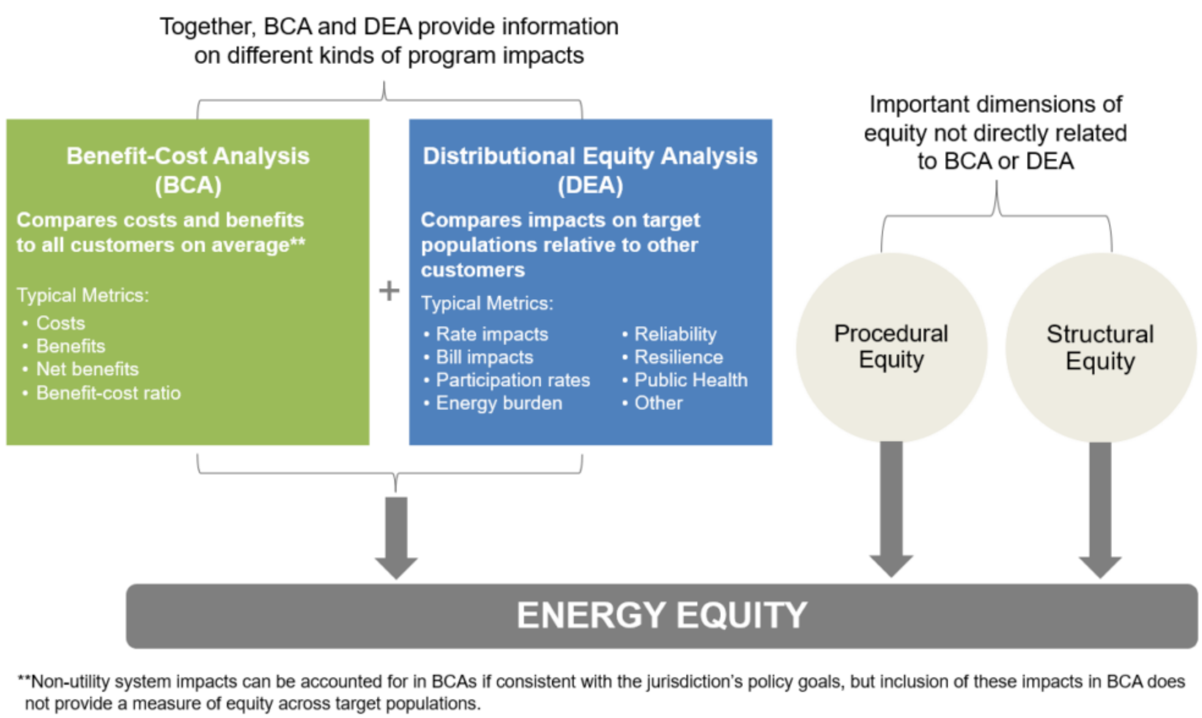

Image from NESP Energy Equity and BCA

Recommendation: Establish clear metrics that identify the affordability, health, and economic benefits of these plans to ensure these plans provide the measurable relief communities need.

- Third-party accountability and ownership of the reporting and monitoring of energy burden metrics within the Commonwealth and EJ communities
- Health impact assessments for projects that capture relevant health endpoints and major health-relevant impact pathways
- On affordability, the state or utilities should carry out research that identifies affordability metrics such as household electricity burden, household electricity affordability gap, and others to assess the likely cost burdens that customers will face so that the ESMP's impact can be publicly known and steps to mitigate risk to LMI households can be identified

Recommendation: Monitoring and evaluation of communities pre- and post-implementation to ensure goals are achieved

- Third-party accountability and ownership of monitoring and evaluation of health and equity metrics
- Mechanisms to close gaps if ESMPs do not provide anticipated relief to affected communities

Supporting AEG Boston 23Q3 Attendees and Task Force Volunteers:
Kathryn Cox-Arslan, New Leaf Energy
Jonathan Stout, Dana-Farber Cancer Institute
Jonathan Buonocore, Boston University
Natalie Hildt Treat, NECEC
Johannes Epke, Conservation Law Foundation
Mary Wambui, Planning Office for Urban Affairs (POUA)
Sarah Sweeney, Advanced Energy Group
Miles Gresham, Neighbor to Neighbor MA
Caleb Benham, Veregy
Anthony Buschur, Ameresco
Audrey Schulman, HEET

For more on this initiative, refer to our event resource page.

About Advanced Energy Group (AEG):
Advanced Energy Group is a 100% minority-owned business supported by sponsors to design and lead stakeholder engagements that deliver systemic change on energy, equity, and resilience in major cities and vulnerable regions in 12-month sprints.

Written Public Comments Submitted to the Grid Modernization Advisory Council

Below are the written comments submitted to MA-GMAC@mass.gov in advance of the November 9, 2023 GMAC meeting. This document includes written submissions of comments made at the two GMAC Listening Sessions on October 30, 2023, and November 1, 2023.

Submitted Comments:

1. **Amaani Hamid, Senior Regulatory Affairs Manager at Leap**, (amaani@leap.ac) – Received 10/12/23. *(Oral comments delivered at the 10/30/23 GMAC Listening Session)*
2. **Rachel Loeffler, Private Landowner in Eversource service territory,** (rachelloeffler@gmail.com) – Received 11/1/23. *(Oral comments delivered at the 10/30/23 GMAC Listening Session)*
3. **Cathy Kristofferson, Pipe Line Awareness Network for the Northeast, Inc.,** (cathy.kristofferson@gmail.com) – Received 11/1/23. *(Oral comments delivered at the 11/1/23 GMAC Listening Session)*
4. **Joint comments from environmental and climate advocates in Massachusetts,** submitted by Priya Gandbhir, Conservation Law Foundation, (pgandbhir@clf.org) – Received 11/1/23.
5. **Graham Turk, MIT Researcher and Eversource customer,** (gturk@mit.edu) – Received 11/2/23. *(Oral comments delivered at the 11/1/23 GMAC Listening Session)*
6. **Leslie Zebrowitz, Co-Chair of Newton EV Task Force,** (evtaskforcenewton@gmail.com) – Received 11/3/23.
7. **NRG Energy, Inc**, submitted by Greg Geller, Stack Energy Consulting, (greg@stackenergyconsulting.com) – Received 11/7/23.
8. **Cape Light Compact**, submitted by Margaret Downey, (mdowney@capelightcompact.org) – Received 11/7/23.

Comments from Leapfrog Power, Inc on ConnectedSolutions' export cap of 150% of peak site load

Leap enables distributed energy resource (DER) providers across North America to provide grid flexibility, delivering revenue for their customers and integrating additional demand-side resources into electricity systems. Leap began participating in ConnectedSolutions this year and already has over 2 MW of load providing grid services via ConnectedSolutions.

Last year, an export cap equal to 150% of peak site load (i.e. the 150% export cap) was implemented for storage assets with an Interconnection Standard Agreement after June 8, 2023 and capacity greater than 50 kW. I am reaching out to urge the Grid Modernization Advisory Council (GMAC) to support Leap's proposal of increasing the export cap to 600% for the 2024 delivery year, which we believe is a more appropriate cap for C&I storage sites as explained in more detail below. Although we firmly believe that having no export cap is the best approach to incentivize and extract the full value of storage assets, we find an export cap of 600% to be a reasonable compromise that addresses concerns the Massachusetts Department of Public Utilities (DPU) has regarding the installation of large batteries while supporting ConnectedSolutions' goal of leveraging these assets to develop a more sustainable grid.

Leap has a number of storage partners with prospective assets that are slated to participate in ConnectedSolutions during the 2024 season and beyond. These batteries are in the 300-500 kW range and have been installed in a wide range of C&I facilities, such as middle schools, for energy security, reliability, grid services, and decarbonization purposes. Programs like ConnectedSolutions enable the deployment of these assets by providing a cutting-edge incentive. However, the 150% export cap severely limits the value these facilities would receive, thus hindering the deployment of these assets at scale or making it difficult to justify the opportunity cost of participating in ConnectedSolutions.

It is our understanding that the 150% export cap was arbitrarily set in order to comply with D.P.U. 22-137, footnote 30 which states "The Department emphasizes the importance of designing energy efficiency measures that aim to primarily decrease on-site load rather than increasing export to the grid." In addition, we understand Joshua Kessler's concern raised during the Active Demand working group held on September 13th regarding out-of-state developers installing oversized batteries in order to take advantage of state incentives. However, we urge stakeholders to weigh this potential risk against the value and upside of removing or increasing the 150% export cap will provide to the many businesses that are installing large storage assets for reliability purposes.

Prior to the establishment of the 150% export cap, BTM storage exports in ConnectedSolutions was limited to the approved Interconnection Service Agreement capacity, which already provides the necessary guardrails to manage storage sites and would be logical to revert to. However, given the DPU's concerns, Leap believes that increasing the export cap from 150% to 600% would be more appropriate as it is based on actual use-cases of storage assets being deployed for clean reliability purposes. For example, at sites like hospitals and clinics (where peak electricity load can range between several hundred kW to upwards of 1 MW), emergency backup is critical and storage assets are a clean alternative to dirty backup generators. To effectively provide emergency backup, it is reasonable to assume that an asset would need to provide 24 hours worth of peak load capacity. Assuming a site with 100 kW of peak load and a 4-hour BTM storage asset, a 600 kW capacity would be necessary to meet 24 hours worth of backup generation (100 kW * 24 hours = 2,400 kWh and for a 4-hour battery to provide 2,400 kWh it would need to have a capacity of 2,400 kWh / 4 hours = 600 kW). As such, the current 50 kW threshold for exemption to the 150% export cap is prohibitively small. Given outages do not occur every day, C&I facilities must also consider other use cases of the asset including demand response participation in order to maximize the value of the asset to both the site and the grid, and should therefore be allowed to participate with its full capacity.

Massachusetts is a leader in developing and implementing innovative programs that leverage DERs for grid services and ConnectedSolutions is one of the country's premier programs, especially when it comes to utilizing behind-the-meter (BTM) storage assets. However, the 150% export cap creates significant barriers that will hinder growth of the commercial storage assets participating in the program. We urge the GMAC to provide comments to the Energy Efficiency Advisory Council (EEAC) in support of Leap's proposal of a 600% export cap for the upcoming year.

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Rachel Loeffler, Private Landowner in Eversource service territory,
(rachelloeffler@gmail.com) – Received 11/1/23. *(Oral comments delivered at the 10/30/23 GMAC Listening Session)*

GMAC (Grid Modernization Advisory Council) Public Comment Listening Session #1 October 30, 2023
Comments provided by Rachel Loeffler

Thank you, Build Trust and Local Relationships	Thank you for hosting this public forum, and accepting public comment on the process. I understand the enormity of the task facing the Commonwealth as it faces the energy transition and increased energy demand. All large-scale infrastructure projects succeed or fail based upon building trust, and local relationships. I am speaking today to request that the public process embrace the small town wisdom: Good neighbors talk to their neighbors and neighbors are stronger together.
Good neighbors talk face to face and take the time to walk through the specific plans.	My mayor [Town Manager] recently said, "When starting a new construction project, even though a project has the right to do the work on their own property, good neighbors talk to their neighbors, walk them through the plans, what to expect during construction, and what the final result of the work will be." I encourage the GMAC to consider a more direct approach to outreach with property owners where utility upgrades and construction takes place. A good neighbor knows that a notice in the mail is insufficient on its own to build trust and set expectations for projects of any complexity.
Reciprocity to Private Landowners	Private landowners who have granted utility company's access to the land are important collaborators and stakeholders in any improvement project. Those who provide an easement to the public utility, do so with a belief in the public good and shared benefit to all. They do so, expecting reciprocity in return-- That the Utility company will use this easement with the utmost care and thoroughness to protect the landowner, the land, and its future value.
Collective Knowledge	Private landowners and abutters have a detailed collective knowledge of the land, how it functions throughout the seasons, and what other features are nearby or adjacent to the proposed work. They should not be excluded from the process, but instead engaged early on to test assumptions of existing conditions and assist in vetting the viability of the final restoration of the land.
Conservation Commission	Historically, notice to a property owner or an abutter of proposed improvements has taken two forms. A general letter indicating the work is

or Letter	about to begin, and or when there is a wetland nearby, notification through the local Conservation Commission.
Unintended impacts	Though this is better than no communication, it is fairly passive and requires the land owner to be vigilant and aggressive in getting access to the proposed plans and work, to ascertain the extent of potential impact to their property.
Adversarial	In addition, it changes what could be a collaborative and proactive relationship, into one that may be adversarial, since any unforeseen negative consequences of the work can only be remediated after the work has begun, sometimes at great cost, and prolonged timelines.
No place to talk	Thirdly, it takes what could be a private discussion between the landowner and utility, into the public forum of the conservation commission. Which is not necessarily appropriate, as the commission's jurisdiction is the protection of wetlands and rare species not people, or private interests.
Wetlands more protected than private home/property owners	Currently the way the improvement work has been approached by the public utilities: Wetlands and Rare Species in the Commonwealth are more protected than individual homeowners and property owners granting easements to the utility company.
Access vs Ownership	Right of Access is not the same as ownership, and should be approached with care and integrity.
Protection	Actions taken through right of access should not diminish the value of the property or home, and should not cause short-term or long-term harm to private infrastructure on the homeowner's land.
New type of public engagement	As you consider a new public engagement process, please consider meeting individually with private landowners whose land you will be entering. During this meeting you should share your existing conditions plans, your temporary construction conditions, and restoration plans. These should be detailed in capturing the existing conditions and showing the limit of work, changes to terrain, management of stormwater, and engineering to protect adjacent areas from harm. The private landowners can help identify issues and complications unknown to the utility company because the utility company may lack detailed knowledge of the land.

Increased transparency Public availability of plans	These plans, and comments by landowners on the plans should be publicly available to all. Any promises made by utility company representatives should be met, with recourse to a government public agency, in case crews on the ground cut corners or lack sufficient information.
Closeout of project with Landowner and State Rep	The process may also benefit from a final walk through with the property owner after the work is complete. Ideally this meeting would take place with a state or local representative, who would thereby have an understanding of the work and its impact throughout their district.
Time Effort Investment	I realize that these modifications to engagement may require more time and effort upfront, but may save time and money in the long run, while strengthening relationships with the landowners granting access through their land.
Thank you	Again thanks for sharing your time and offering the opportunity to speak, and I look forward to neighborly collaboration in the years ahead.

Thanks again,
Rachel Loeffler

P•L•A•N
PIPE LINE AWARENESS NETWORK
FOR THE NORTH EAST, INC.
www.plan-ne.org

November 1, 2023

Via email: MA-GMAC@mass.gov

Grid Modernization Advisory Council
c/o Department of Energy Resources
100 Cambridge Street, 9th Floor
Boston, MA 02114

RE: GMAC Public Listening Session #2

To Commissioner Mahoney and GMAC members,

Please accept this written version of my spoken testimony given for the Pipe Line Awareness Network for the Northeast at the GMAC Public Listening Session #2 from here in Ashby in Unitil's Fitchburg Gas & Electric service area where I am an electric ratepayer.

This testimony focuses on hybrid heating, the ESMPs reliance on hybrid heating as a method of reducing electric peak & needed grid mods, and the idea of incentivizing fossil-backed hybrid heating.

At the October 12th GMAC meeting, the Department's consultant presented recommendations during their review of sections 8,9 & 11 of the ESMPs. On slide 53 they listed a recommendation for MassSave to "Provide incentives that favor fossil-fueled supplement/hybrid ASHP over pure ASHP." Not shown on the slide, but presented was that this would accomplish a 95% emissions reduction. That 95% figure is reflected in Eversource's ESMP [at 412] for their modeling of 10, 20 and 30F hybrid heating switchover temperatures which shows "At 10 F, the total hours under back up system would be an average of 34 hours a year, achieving 95% of the GHG reductions as compared to a full replacement heat pump."

The Eversource ESMP [at 476] says "Hybrid Heating Solutions utilize a backup fuel source that can be burned during extreme cold conditions (See Section 8.2.1.3 for details) and therefore allow the re-dimensioning of ASHPs to smaller units that can operate due to a lower floor temperature at a higher COP." And that relying on those smaller unit hybrid solutions allow for "significant impact on the overall peak system demand of the electric system, allowing an increase in the system utilization, allowing for less distribution and transmission investments."

To me that sounds like decades of purposefully undersized ASHP installs reliant on a combusted fuel for cold weather heating only able to handle temps above whichever switchover temp was chosen. And less than the needed electric grid buildout.

No temperature switchover was given in any of the ESMPs, but they all discussed hybrid heating as a solution for reducing electric grid buildout.

National Grid's Long Range Forecast & Supply Plan in 22-149 approved yesterday[1] by the DPU contained a 30F switchover which according to the Eversource modeling [at 412] results in 845 hours a year and only 65% of the GHG emissions reductions.

Promoting fossil fuel use over full electrification is the wrong direction for rapid transition. It can only be viewed as least cost if you don't consider other impacts, some of which are detailed below.

Considering that ASHP have an expected service life of 20 or more years - is that 20 or more years bringing us right up to 2050 of combusted gas for winter heating?

What happens when the retained fossil heating system's life is over, or unexpectedly dies early, or anytime within the hybrid heat pump system's 20+ year service life? Does that mean a new fossil system for "backup" since that "re-dimensioned" smaller unit hybrid setup isn't capable of whole home heating? Will that be incentivized as well since incentives pushed the purchase in that direction in the first place?

I did see in the GMAC Meeting Summary "There was discussion about whether natural gas as a backup for heat pumps is a viable solution, particularly in light of concerns over ongoing maintenance of gas pipelines." For me, I wonder how delivered fuels can be a viable backup solution since those companies don't make their money on infrastructure. 34 hours of fuel sold per customer doesn't exactly sound like a viable business model.

I did see that at the following GMAC meeting on the 26th no check mark in your column for accepting that suggestion from the consultant but don't imagine that's the end of it. [*Ed. Thank you for explaining I misunderstood the checkmark system.*] Can the GMAC recommend against incentivizing fossil fuel based systems over full electrification?

The Seavey presentation[2] at the GSEP Working Group meeting on the 20th showed the costs those retained gas ratepayers will help payoff to be $34.4B to maintain the gas distribution system's leaks and old pipes. There are other capex expenses for gas expansions and resiliency work that the retained ratepayers will help payoff also all for the so-called backup heating. That seems a lot of money that could be put towards grid modernization not shoring up a crumbling pipeline system.

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[1] Order in D.P.U.22-149 *Petition of Boston Gas Company d/b/a National Grid to the Department of Public Utilities pursuant to G.L. c. 164, § 69I, for Review and Approval of its Long-Range Forecast and Supply Plan for the period of November 1, 2022, to October 31, 2027* "The Company assumed that the controls run the heat pump when outside temperatures are above 30 degrees Fahrenheit and switch to the gas system when temperatures are 30 degrees Fahrenheit or lower." at 21 available at https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18158955

[2] Dorie Seavey, PhD, *"GSEP's cumulative costs"* available at https://www.mass.gov/doc/seavey-gsep-cost-presentation/download

We all talk about decarbonization and how we need emission reductions, but we need more than reduction, we need emissions elimination.

All ESMP mentions of ASHP installs need to specify if whole home/full or hybrid/partial. 1 million whole home installs would be the elimination of emissions which is quite different than 1 million hybrid/partials which may only be reducing emissions by 65%.

Section 11 feels lacking for all three ESMPs. They are all pretty much the same text from the template so are thin and need work. It's unfortunate because better gas-electric coordinated planning to decommission the gas systems and build up the electric grid is needed rather than coordinating on hybrid heating to keep the $34B gas system in service.

Thank you for the opportunity to provide input to this critical undertaking.

Respectfully submitted,

Cathy Kristofferson
Pipe Line Awareness Network for the Northeast, Inc.
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Via Electronic Delivery Only
MA-GMAC@mass.gov

November 1, 2023

Commissioner Elizabeth Mahony, Chair
Grid Modernization Advisory Council
c/o Massachusetts Department of Energy Resources
100 Cambridge Street, 9th Floor
Boston, MA 02114

Subject: Comments on Electric Distribution Companies' Draft Electric Sector Modernization Plans

Dear Chair Mahony and Members of the Grid Modernization Advisory Council,

The undersigned respectfully submit these comments regarding the draft Electric Sector Modernization Plans ("ESMPs") filed by the Electric Distribution Companies ("EDCs")[1] with the Grid Modernization Advisory Council ("GMAC"). We thank the GMAC for your hard work to ensure that as Massachusetts moves toward its clean energy future – which will rely heavily on electrifying our buildings and transportation sectors – our electric distribution system is able to keep up with increasing demand and load growth with the necessary reforms made in a manner that protects the Commonwealth's environmental justice communities. To that end, we make the following recommendations with the hope that when the ESMPs are filed with the Department of Public Utilities ("DPU") in the next phase of this endeavor, these efforts will result in successful outcomes.

Legislative and Procedural Background

In recent years, Massachusetts climate law and policy has been strengthened significantly. In March 2021, the Global Warming Solutions Act ("GWSA") was updated by the enactment of An Act to Create a Next-Generation Roadmap for Massachusetts Climate Policy ("Roadmap Law"), under which the Commonwealth is mandated to achieve net-zero GHG emissions, or an 85% reduction below 1990 emissions levels, by the year 2050.[2]

In addition, in December 2020, Massachusetts' Executive Office of Energy and Environmental Affairs ("EEA"), in collaboration with Massachusetts Department of Environmental Protection ("MassDEP") and Massachusetts Department of Energy Resources ("DOER") released its 2050 Decarbonization Roadmap,[3] as well as its Interim Clean Energy and Climate Plan ("CECP") for 2030.[4] A final Clean Energy and Climate Plan for 2025 and 2030 was released on June 30, 2022

[1] The Massachusetts EDCs that have filed ESMPs with the GMAC are Eversource, National Grid, and Unitil, herein collectively "the EDCs" unless individually named.
[2] 2021 Mass. Acts Chapter 8.
[3] Mass. Exec. Office of Energy and Env't. Affairs, Massachusetts's 2050 Decarbonization Roadmap (2020), Available at https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download.
[4] Mass. Exec. Office of Energy and Env't. Affairs, Clean Energy and Climate Plan for 2030 (2020), Available at https://www.mass.gov/doc/interim-clean-energy-and-climate-plan-for-2030-december-30-2020/download

and included sublimits by sector for the first time as required by the Roadmap Law[5] and a Clean Energy and Climate Plan for 2050 ("2050 CECP") was released in December 2022.[6] Pursuant to the 2050 CECP, because it achieves Massachusetts' GHG emissions reductions mandate at the least cost, "[t]he dominant strategy to decarbonize transportation and buildings is electrification."[7] The 2050 CECP noted the establishment of the GMAC in An Act Driving Clean Energy and Offshore Wind and the GMAC's role in providing recommendations to the EDCs "to improve grid reliability and resiliency, further enable distributed energy resources and electrification, and minimize or mitigate costs and risks to ratepayers."[8]

In August 2022, the Massachusetts Legislature directed the DPU to require EDCs to develop and file ESMPs, the purpose of which is:

> to proactively upgrade the distribution and, where applicable, transmission systems to: (i) improve grid reliability, communications and resiliency; (ii) enable increased, timely adoption of renewable energy and distributed energy resources; (iii) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; (iv) prepare for future climate-driven impacts on the transmission and distribution systems; (v) accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and (vi) minimize or mitigate impacts on the ratepayers of the commonwealth, thereby helping the commonwealth realize its statewide greenhouse gas emissions limits and sublimits under chapter 21N.[9]

The Legislature also set forth elements which must be included in the ESMPs, and determined certain timelines and benchmarks for measuring success.[10] In addition to the legislative directives for the GMAC, the DPU has reviewed petitions from the EDCs regarding grid modernization and has pre-authorized certain grid-facing and customer-facing investments, while costs from grid-facing investments will be recovered annually outside of the usual ratemaking process.[11]

The GMAC has taken the approach of utilizing guiding questions to evaluate the EDCs' draft ESMPs. The intent of using these guiding questions is to ensure that the resultant ESMP filings at the DPU will ensure results that include equity both in process and in outcomes; least-cost investments in the electric distribution system or alternatives; achievement of Massachusetts' greenhouse gas ("GHG") emissions limits and sublimits under the GWSA; optimization of customer benefits and cost-effective investments; and minimization or mitigation of impacts on

[5] Mass. Exec. Office of Energy and Env't Affairs, Massachusetts Clean Energy and Climate Plan for 2025 and 2030 (Jun. 30, 2022), available at: https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download.
[6] Mass. Exec. Office of Energy and Env't Affairs, Massachusetts Clean Energy and Climate Plan for 2050 (Dec. 2022), available at: https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download.
[7] 2050 CECP at xiv.
[8] 2050 CECP at xvii.
[9] M.G.L. c. 164, §92B.
[10] M.G.L. c. 164, §92B.
[11] MA DPU Docket Nos. 21-80-A and -B, 21-81-A and -B, 21-82-A and -B

ratepayers, especially low-income ratepayers. The undersigned agree with these questions as providing appropriate guidelines for the GMAC's review of the ESMPs.

Since the endeavor to modernize the electric distribution system is rooted in the need to achieve Massachusetts' legal mandate to achieve net-zero GHG emissions under the Roadmap Law, each ESMP which moves from the GMAC process to review at the DPU must demonstrate achievement of such GHG emissions limits. Additionally, impacts on ratepayers in general should be minimized or mitigated through the use of cost-effective and least-cost investments – so long as these investments are demonstrated to lead the Commonwealth to achievement of its GHG emissions reduction target – but it must also be understood that low-income ratepayers and members of environmental justice communities need additional protections to protect these ratepayers from bearing the burden of the costs of transitioning to Massachusetts' clean energy future.

The ESMPs Require Addition and Clarification of Information Regarding Certain Parameters and Technologies

Once filed at the DPU and approved, the ESMPs will provide a path forward for the modernization of electric distribution grid infrastructure throughout Massachusetts. Accordingly, each EDC's ESMP must fully flesh out the information needed to undertake this effort from the start, including thorough consideration of emerging technologies such as DERs and Battery Storage, as well as the demand implications of electrification demonstrated by load forecasting.

1. The draft ESMPs should be supported with additional information including but not limited to:
    a. timing and success of interconnection queue applications;
    b. battery storage and DERs, including third-party assets;
    c. seasonal and geographic impacts on the system; and
    d. outreach to interconnection and resource stakeholders.
2. Consistency among the EDCs' ESMPs is necessary to ensure a just and efficient transition to our clean energy future.
3. As the EDCs work through finalizing their ESMPs, they should continue to look forward to next steps, including anticipating increased appetite for clean energy resources from consumers, ensuring that the grid itself does not remain a barrier to the clean energy transition.

In addition to the guiding questions prepared by the GMAC's consultant, Synapse Energy Economics, the undersigned support the comments of Advanced Energy United and Northeast Clean Energy Council ("NECEC") filed in July 2023, including the authors' request to include a provision for outreach to interconnecting customers in Section 3 ("Stakeholder Engagement") of the ESMPs.[12] The undersigned support the recommendation of Advanced Energy United and NECEC that the EDCs provide additional information in Section 4 ("Current State of the Distribution System") about geographic parameters as well as information about the timing and

[12] Comments of Advanced Energy United and NECEC (July 13, 2023) at 1-2, available at: https://www.mass.gov/doc/gmacpublic-comments-on-edcs-draft-outline-advanced-energy-united-northeast-clean-energy-council/download.

success of interconnection queue applications, including the time between the filing, approval, and operation. The ESMPs should also address battery storage, seasonal issues, system peaks, and congestion in Section 5 ("5- and 10- Year Electric Demand Forecast"), as these are considerations which are anticipated to have significant impacts on the region's evolving electric grid.[13]

In its ESMP, Eversource does not seem to address the July 2023 recommendations from Advanced Energy United and NECEC regarding the need for outreach to interconnection customers. The undersigned request that this be added to their ESMP. Eversource also did not provide much by way of additional clarity regarding the interconnection queue process including the timing between filing, approval, and operation. Eversource did, however, note changes to the interconnection process for Distributed Energy Resources ("DERs") which were made to address significant interconnection queue backlogs by developing a framework for more comprehensive solutions which modified the DER planning process to standardize and expedite interconnection studies in the planning regions.[14] Similarly, National Grid's ESMP will benefit from additional information regarding battery storage, seasonal issues (including peaking), and impacts to load. Although these issues are raised in Section 5 of National Grid's ESMP, they are only discussed at a very high level.[15] Like Eversource and National Grid, Unitil did not address stakeholder process for interconnection customers. Unitil also did not address the recommendations regarding the interconnection queue. Further, although it provided some detail on seasonal peaking and DERs, Unitil did not widely explore battery storage or electric vehicles in its 5- and 10- year electric demand forecasting, noting slow adoption.[16] National Grid and Unitil should update their ESMPs to provide information regarding the interconnection process for DERs or to explain how they plan to address this issue.

The undersigned also support the July 13, 2023 comments of Cape Light Compact regarding the importance of reporting and metrics, including how the EDCs will coordinate reporting across its different dockets to improve outcomes from decisions regarding matters such as time-varying rates, performance-based ratemaking, energy efficiency, advanced metering, electric vehicles, peak demand reductions.[17]

Overall, the ESMPs should provide a framework for how the EDCs will move toward our new, modern electric grid, and should only include recommendations and steps that will ensure rapid, responsible progress toward Massachusetts' clean energy future. To that end, recommendations which serve to backpedal on this progress cannot be a part of this work. For example, assertions that fossil fuel backups are needed to ensure reliability of heat pumps[18] are not only false, but also perpetuate misinformation about the reliability of electrification technologies. Additionally,

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[13] Comments of Advanced Energy United and NECEC (July 13, 2023) at 2-3, available at: https://www.mass.gov/doc/gmacpublic-comments-on-edcs-draft-outline-advanced-energy-united-northeast-clean-energy-council/download.
[14] Eversource ESMP at 115.
[15] National Grid ESMP at 197 et seq.
[16] Unitil ESMP at 51 et seq.
[17] Comments of Cape Light Compact (July 13, 2023) at 2, available at https://www.mass.gov/doc/gmacpublic-comments-on-edcs-draft-outline-cape-light-compact-jpe/download.
[18] See slide 9, Synapse presentation to GMAC on Oct. 12, 2023, available at: https://www.mass.gov/doc/gmac-meeting-slides-10-12-2023/download.

the EDCs must consider the value of not only their own infrastructure, but all assets which may be incorporated into the electric distribution grid, including third-party DERs. With these changes, the ESMPs will provide robust and detailed planning for Massachusetts' future electric grid.

The Modernized Electric Distribution Grid Must be Designed and Constructed to Withstand the Already Evident Impacts of Climate Change

While we continue to work to reduce GHG emissions and limit global warming to 1.5 degrees Celsius, the unfortunate reality is that the impacts of climate change, including extreme weather and increased frequency and severity of storms, are upon us. As Massachusetts transitions to a clean energy economy by electrification of our buildings and transportation systems, the durability and resilience of the electric distribution grid becomes more critical than ever before. Key to ensuring a resilient and reliable electric grid is consistency among the EDCs regarding best practices, especially as related to planning for hazard mitigation and adaptation.

1. The ESMPs should be made consistent regarding planning for mitigation of and adaptation to climate hazards including storms, wind, flooding, and extreme temperatures.
    a. Consistent standards regarding substation and infrastructure siting and construction should be utilized.
2. Reliability and resilience should be elevated as priorities with the intent of eventually mandating standard practices and procedures for the EDCs to utilize when addressing reliability and resilience.

As with people around the world, Massachusetts residents rely on the use of electricity in their daily lives for cooking, working, lights, heat, recreation, transportation, and more. As Massachusetts transitions to a clean energy future based heavily on electrification of buildings and transportation, the need for our electric system to be reliable and resilient will only grow. Accordingly, it is vital that the modernized electric distribution grid be designed for longevity to avoid repeatedly incurring replacement costs; to withstand increased strain from higher load; and to endure climate hazards such as flooding, heat waves, cold snaps, wind, and storms.

Planning for Mitigation of and Adaptation to Climate Hazards

In its Rulemaking Petition to the DPU, submitted on May 3, 2023, CLF has recommended the addition of 220 CMR 10.000: Hazard Mitigation and Climate Plans to the DPU's regulations.[19] Under the proposed regulation, all investor-owned utility companies would be required to develop Hazard Mitigation and Climate Adaptation Plans ("HMCAPs") which include, at a minimum: an evaluation of climate-related risks for the company's service territory including changes in temperature extremes, humidity, precipitation, sea level rise, and extreme storms; an assessment of potential impacts of climate change on existing operations, planning, and physical

[19] CLF Petition for MA DPU Rulemaking to Establish Regulations to Implement the GWSA and An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy (May 3, 2023), at 47, available at: https://www.clf.org/wp-content/uploads/2023/05/Conservation-Law-Foundation-GWSA-DPU-Petition-May-3-202333.pdf.

assets; identification and prioritization of climate adaptation strategies; an evaluation of costs and benefits against a range of possible future scenarios and climate adaptation strategies; and an implementation timeline, with benchmarks, for making changes in line with the findings of the study to existing infrastructure to ensure reliability and resilience of the g[20] Identification of the criteria noted above will serve to ensure that investor-owned utility companies are appropriately positioned to take on the unavoidable impacts of climate change which will impact our energy systems.

In 2018, the Commonwealth developed the Massachusetts Integrated State Hazard Mitigation and Climate Adaptation Plan ("SHMCAP") in compliance with Governor's Executive Order 569, as a comprehensive plan to integrate adaptation strategies for climate change with general hazard mitigation planning and maintaining Massachusetts' Stafford Act eligibility for federal disaster and hazard mitigation funding.[21] The SHMCAP recommended 108 actions across five main goals: to integrate programs and build institutional capacity; to develop forward-looking policies, plans, and regulations; to develop risk-reduction strategies for current and future conditions; to invest in performance-based solutions; and to increase education, awareness, and incentives to act.[22] Although the SHMCAP provides an adequate starting point for the EDCs' evaluation and planning of resilience measures for Massachusetts' electric distribution grid, enactment of CLF's proposed regulation requiring investor-owned utilities to develop their own HMCAPs will allow for more precision in planning and enable utilities to keep their plans more up-to-date than only having a common plan across the Commonwealth allows. Accordingly, we recommend that while action from the DPU on CLF's petition is awaited, the GMAC instructs the EDCs to incorporate the principles of the HMCAPs, noted above, into their resilience planning in Section 10 of the ESMPs. As demonstrated below, the three EDCs participating in the ESMP process express a range of design standards; we encourage the GMAC to recommend changes which bring these design standards into alignment, as a broad statewide framework will provide necessary consistency and enable the EDCs to adhere to best practices. In addition to recommending incorporation of the principles regarding climate resilience included in CLF's Rulemaking Petition to the DPU, we note the following.

Utility Specific Comments

Eversource's ESMP relies on the SHMCAP as well as its own Climate Vulnerability Study, which significantly expands the scenarios envisioned in the SHMCAP, looks at extreme temperature, heavy precipitation, drought, sea level rise, and storm surge through 2080. Eversource anticipates a reduction in storm costs with implementation of their planning.[23]

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[20] Conservation Law Foundation, *CLF Petition for MA DPU Rulemaking to Establish Regulations to Implement the GWSA and An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy* (May 3, 2023), at 47-48, available at: https://www.clf.org/wp-content/uploads/2023/05/Conservation-Law-Foundation-GWSA-DPU-Petition-May-3-202333.pdf.

[21] MA Executive Office of Energy and Environmental Affairs ("EEA"), *Massachusetts State Hazard Mitigation and Climate Adaptation Plan*, September 2018, available at: https://www.mass.gov/files/documents/2018/10/26/SHMCAP-September2018-Full-Plan-web.pdf.

[22] MA Executive Office of Energy and Environmental Affairs ("EEA"), *Massachusetts State Hazard Mitigation and Climate Adaptation Plan*, September 2018, at 12, available at: https://www.mass.gov/files/documents/2018/10/26/SHMCAP-September2018-Full-Plan-web.pdf.

[23] Eversource ESMP at 489 et seq.

Eversource rightly recommends that the SHMCAP action titled "Regional power grid planning and incorporation of climate change data" be elevated from a medium priority action to a high priority action and the Massachusetts EDCs should be added as partners for the action titled "Build energy resiliency".[24] As more aspects of Massachusetts residents' daily lives become reliant on electricity, it has become increasingly critical that EDCs make necessary upgrades to enhance the electric grid's reliability and resilience to minimize the frequency and duration of outage events. In 2023, Eversource published an updated Climate Adaptation and Mitigation Plan, which mentions the company's vulnerability assessment and that the company plans to incorporate lessons from that assessment into transmission and distribution infrastructure design and standards.[25] The Climate Adaptation and Mitigation Plan is thus more of an update on business-as-usual reliability work and a statement of intent to do actual climate adaptation planning. This statement of intent to do adaptation planning is echoed in the ESMP: "By the end of 2024, the Company plans to translate these Climate vulnerability study results into updates to its Distribution Planning and Equipment Design standards."[26] While we appreciate the stated intention to plan for a resilient electric grid, this planning must be mandatory and enforceable, and performed with uniformity and oversight provided by establishment of a regulation for HMCAPs.

Eversource identified 318 critical impacted zones and established[27] By Eversource's calculation, undergrounding the most critically impacted areas of distribution lines will result in a 98% improvement of the System Average Interruption Duration Index ("SAIDI"), but costs about twice as much per mile as the next most expensive solution (aerial cable).[28] The up-front cost of undergrounding should be compared with cost data for operations and maintenance of the various solutions to determine how frequently each would require repair or replacement. Finally, regarding the elevation of substations, we would like to see additional Rate Map ("FIRM") used to identify locations for differing elevation standards; specifically when the map was last updated and when the Company's standards used in determining substation elevation were last updated[29]

National Grid also notes that it regularly reviews and updates its distribution construction standards with a focus on changes designed to improve distribution system performance by reducing the number of customers impacted by outages, reducing the duration of outages, and mitigating the impact on customers during outages.[30] National Grid followed a four phase framework regarding vulnerability risk assessment, the phases being: validation of climate science, hazards, and assets in scope; assessment of vulnerability of each asset to each hazard; prioritization of assets identified in Phase 2; and development of adaptation measures to address assets with the highest risk[31] – a similar concept to Eversource's identification of critical impact zones and design of a portfolio of resilience solutions. National Grid also notes the benefits of undergrounding distribution lines but identifies the risk to the above-ground components of the

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[24] Eversource ESMP at 496.
[25] Eversource Climate Adaptation and Mitigation Plan, available at: https://www.eversource.com/content/docs/default-source/community/eversource-camp-plan.pdf.
[26] Eversource ESMP page 25
[27] Eversource ESMP at 503.
[28] Eversource ESMP at 504.
[29] Eversource ESMP at 509.
[30] National Grid ESMP at 360.
[31] National Grid ESMP at 377.

system near coastal zones.[32] National Grid provides electric distribution services to much of the coastal region north of Boston, as well as some coastal areas south of Boston and most of Worcester County.[33] Coastal flooding also poses a threat to substations, and National Grid has begun discussion to increase their flood mitigation design criteria to a more stringent criteria in anticipation of increased flood levels in the future.[34] National Grid identifies moving infrastructure inland[35] as an option for alleviating the risk associated with coastal flooding. In addition to the assessments conducted so far, and as noted above, we recommend developing a full HMCAP to fully identify the risks, vulnerabilities, and potential solutions needed to develop a reliable and resilient electric distribution system and to provide a method to begin standardizing and coordinating resilience efforts across the EDCs' service territories.

Unitil notes that it has identified the same risks to its infrastructure as contained in the SHMCAP.[36] Unitil identifies solutions via its Storm Resiliency Program, which differs from its vegetation management program by reducing tree exposure along certain circuits to improve performance during major storms, but does include removing all overhanging vegetation and performing intensive hazard tree review and removal.[37] Unitil remarks that it did consider undergrounding as an option for hardening its electric distribution system but indicates it was deterred by the high cost of burying the electricity lines.[38] Noting the significant benefits of trees, especially in urban areas such as Fitchburg , where the shade and air quality benefits of tree canopy are critical to protecting communities from the impacts of climate change. Accordingly, with the understanding that Unitil is concerned about incurring significant costs associated with undergrounding, that the company look to strike a balance between tree removal and undergrounding.

Any Steps Toward Achievement of Massachusetts Climate Goals Must Center on Principles of Environmental Justice

The DPU, which will ultimately review these ESMPs, is required to consider environmental justice in its decisionmaking, in addition to GHG emissions reductions, costs, and reliability. While environmental justice has been treated as a procedural box to check, the reality is that protection of our most vulnerable communities is key to achieving a just transition to Massachusetts clean energy future. All efforts to eliminate GHG emissions and develop a modern electric grid must center the needs of environmental justice communities, in terms of cost, impacts, and procedure.

1. The ESMPs should all include information regarding the EDCs' efforts to incorporate principles of environmental justice into their planning, regardless of the specific makeup of their service territories.
2. The ESMPs should provide additional information regarding barriers for grid

[32] National Grid ESMP at 369.
[33] Electricity Providers by Municipality, available at https://www.mass.gov/doc/map-of-electric-company-electric-service-territories-by-municipality/download.
[34] National Grid ESMP at 371.
[35] National Grid ESMP at 371.
[36] Unitil ESMP at 151.
[37] Unitil ESMP at 159-160.
[38] Unitil ESMP at 160.

modernization for low and middle-income consumers as well as renters and multi-family dwellings as well as solutions for such impediments.

3. The EDCs and DPU should implement the lessons of the Attorney General's Stakeholder Working Group regarding public participation and engagement with the public for proceedings before the DPU.

All electric ratepayers will be impacted by the significant investments in electric infrastructure necessary to eliminate GHG emissions in the Commonwealth. With careful and diligent planning, however, these expenses can and should be minimized or mitigated using cost-effective and least-cost investments. Member of environmental justice communities – who have borne the burdens of poor infrastructure siting and planning and who suffer disproportionately from the impacts of increased energy rates – must be provided with protections over and above the general population.

Utility Specific Recommendations for Improvement of Environmental Justice Aspects of the ESMPs

In its ESMP, Eversource adopts state definitions of terminology relating to environmental justice, including "energy benefits", "environmental benefits", "environmental justice", "environmental justice population" and "meaningful involvement" and defines equity as "engaging all stakeholders, including Eversource's customers and communities with respect and dignity while working toward fair and just outcomes, especially for those burdened with economic challenges, racial inequity, negative environmental impacts and justice disparities."[39] While Eversource's definition of "equity" is a good starting point, we encourage the company to tweak the language to be more direct regarding provision of beneficial outcomes for members of environmental justice populations and to also incorporate their customers' access to clean energy resources into this definition. In general, Eversource appears to have thought through some ways to improve environmental justice outcomes for communities, including providing turnkey installation services for EV chargers for residents of environmental justice communities or customers enrolled in the low-income discount rate as well as rebates for EV chargers for multi-unit dwellings and public and workplace EV charging.[40] Eversource also indicates a plan to focus workforce development efforts toward environmental justice communities.[41] To round out the company's consideration of environmental justice matters in its ESMP, we recommend additional consideration of incentives and planning for increased energy efficiency and grid modernization upgrades to tenant-occupied dwellings, as renters generally lack the funds, knowledge, or incentive to undertake such efforts and landlords may require mandatory conversions to be compelled to act.

National Grid includes its draft Equity and Environmental Justice Policy and Stakeholder Engagement Framework in the appendices to its ESMP and seeks feedback on this framework.[42] The framework is "intended to articulate [National Grid's] commitments to centering equity and environmental justice, building on [its] existing outreach and engagement practices, and

[39] Eversource ESMP at 35.
[40] Eversource ESMP at 279.
[41] Eversource ESMP at 397.
[42] National Grid ESMP at 30.

leveraging input from environmental justice stakeholders … EEA and the Attorney General's Office."[43] National Grid notes the need for new efforts to fully integrate equity and environmental justice into its operations, planning, programs, and business operations and identifies multiple efforts targeted at stakeholder engagement, such strengthening the company's relationship with indigenous communities in its service territory, providing economic incentives for energy efficiency and EVs, and workforce development.[44] We look forward to learning more about these efforts and providing feedback as additional information is provided. Regarding revisions to its ESMP before filing with the DPU in 2024, we encourage National Grid to work through Sections 5 and 6 and incorporate discussion on how environmental justice considerations will be addressed in its demand forecasting and planning processes, as currently those sections lack this information.

Unitil discusses stakeholder engagement with environmental justice communities in Section 3 of its ESMP as the other EDCs do. However, the only other mention of environmental justice appears in Section 10 "Reliable and Resilient Distribution System".[45] We understand that a large part of Unitil's electric distribution service territory is comprised of environmental justice populations, but nevertheless encourage the company to go back through its ESMP, especially the sections regarding electric grid demand and planning over the next five to ten years, and add detail about whether and how consideration of environmental justice principles played a role in development of its ESMP.

Recommendations for Improvement of Process Relating to the ESMPs

Each of the EDCs addressed stakeholder outreach to environmental justice communities in Section 3.5 of their ESMPs. In developing their stakeholder outreach, the EDCs can look to the efforts of climate and environmental justice advocates as well as state and local governments. In Massachusetts, two notable examples of this important work exist. Beginning in 2021, the Massachusetts Attorney General's Office ("AGO") convened a Stakeholder Working Group ("SWG") with members from environmental and climate justice advocacy groups[46], which discussed barriers to participation in energy regulatory proceedings. The group convened regularly for almost two years, and in May 2023 their work culminated in the release of the report "*Overly Impacted & Rarely Heard: Incorporating Community Voices into Massachusetts Energy Regulatory Processes*"[47] which provides recommendations for improvement of the energy regulatory process as the Commonwealth moves toward a decarbonized energy future. The report included input from public surveys, interviews, and multiple focus groups, all of

43 National Grid ESMP at PDF page 412.
44 National Grid ESMP at PDF page 413.
45 Unitil ESMP at 168.
46 The SWG participants included GreenRoots, National Consumer Law Center, Massachusetts Climate Action Network, Alternatives for Community & Environment, Regulatory Assistance Project, Conservation Law Foundation, Vote Solar, Environmental Defense Fund. Support was also provided by Strategy Matters and Neighbor to Neighbor.
47 Mass. Atty. Gen. "Overly Impacted & Rarely Heard: Incorporating Community Voices into Massachusetts Energy Regulatory Processes" (hereafter "SWG Report") (May 2023), available at: https://www.mass.gov/doc/overly-impacted-and-rarely-heard-incorporating-community-voices-into-massachusetts-energy-regulatory-processes-swg-report/download.

which provided valuable insight into the public perception and understanding of energy regulatory processes.

Also in 2021, the DPU opened an inquiry on its own motion into procedures for enhancing public awareness of and participation in its proceedings.[48] In this matter, climate and environmental justice advocates provided insights on how proceedings can be more accessible for the public to understand both the nature and impact of project applications and encouraging public reactions to such project applications. We encourage the EDCs to turn to the recommendations outlined in filings in that docket for additional recommendations on how to engage with environmental justice communities.

Before the EDCs can establish regulations for ensuring energy infrastructure procedures include meaningful engagement with the public, the barriers to such meaningful engagement must be identified. The EDCs should apply the lessons learned from the SWG's performance of this exercise and the DPU should examine the appropriateness and adequacy of this review. The SWG put forth recommendations for reforming the Commonwealth's approach to public engagement in energy infrastructure proceedings, first identifying barriers to public engagement in general, and then identifying specific procedural steps for public engagement, such as intervention, hearings, and adjudication.[49] The SWG recognized that due to its technical complexity, interested persons needed to expend a significant amount of time and resources to gain a working knowledge of energy proceedings. Accordingly, the SWG issued a number of recommendations, such as non-technical, plain language summaries of documents in proceedings, website improvements, increased staffing and interaction between staff and members of the public, and free access to transcripts.[50] The barriers faced by interested parties will vary from project to project and state to state and there may be situations where discretion or flexibility is warranted. The EDCs may find, as the SWG did, that the public wants to see more transparency in proceedings so that they can more easily participate in and impact proceedings.[51] One way to improve efficiency and increase the likelihood of successful outcomes is to increase pre-filing community engagement notices before undertaking a particular project.[52]

<u>Notice Requirements</u>

In addition to meeting legal notice requirements, the EDCs should distribute notices by posting language-appropriate materials in gathering spaces that are commonly visited by the public. This may include places of worship, community and senior centers, grocery stores, schools, laundromats, post offices, bus and train stations, and large multi-unit residential buildings. Such notices should be printed on brightly colored paper and written in large text to draw attention. In some cases, social media may be a useful tool in providing notice. In addition to publication on the project proponent's social media[53], the information can be shared by other interested parties such as municipal bodies, elected officials, community-based organizations ("CBOs"), and

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[48] See Dept. of Public Util. Docket No. 21-50, *Vote and Order Opening Inquiry* (2021).
[49] SWG Report at 2.
[50] SWG Report at 6.
[51] SWG Report at 6.
[52] SWG Report at 7.
[53] SWG Report at 33, 38, 71.

others. News outlets also typically have associated social media accounts where notice can be published. On social media, as with other formats, the notice document should be translated into the appropriate languages for the communities expected to be impacted by the activity.[54]

The EDCs should also engage with municipal legislative bodies, municipal regional and planning commissions, local elected officials, tribal serving organizations and tribal communities (both council and programs, and members), and small businesses in areas relevant to a particular proceeding to identify CBOs that should receive public notices. Environmental NGOs and CBOs are often already engaging with local stakeholders, such as municipal legislative bodies, municipal and regional planning commissions, local elected officials, tribal serving organizations and tribal communities (both council and programs, and members, and small business to identify best practices for holding public hearings in a given community. The EDCs should reach out to all such groups and take advantage of the existing connections to affected communities to ensure that outreach extends to as wide an audience as possible. This outreach process should include building relationships with environmental justice populations using trusted advocates to foster open and respectful communication, to better understand and apply community-specific best practices.

Hearings

A lingering impact of the COVID-19 pandemic, virtual meetings and hearings have taken a strong grasp on the way we do business and, indeed, how we conduct our everyday lives. This has had great benefits for public process, as virtual hearings have enabled many people who would otherwise be unable to engage with public meetings and hearings due to obligations such as work, childcare needs, household chores, or difficulty commuting to a meeting place to listen and participate in such proceedings.[55]

Virtual or hybrid hearings must remain the norm. Virtual access has promoted greater and more equitable participation in public bodies.[56] Hybrid hearings allow interested parties to attend hearings in person if they are able while still ensuring that members of the public who cannot attend in person can still participate. Additionally, the Department should provide multiple time options, including times during non-business hours, such as weekends and evenings, for public hearings to ensure that people who cannot leave work to attend a hearing or who work multiple jobs can participate.

The EDCs should ensure that for any in-person hearings, the site that is chosen meets requirements for ADA[57] accessibility, is close to public transportation if available or has ample and low-cost parking, is equipped for a hybrid component, and is set up in a way that facilitates discussion and participation. Tools such as headphones should be available for those who are

[54] SWG Report at 32.
[55] SWG Report at 52.
[56] *See, e.g.*, Kim Driscoll, *Legislature Should Not Be Exempt from Open Meeting Law*, BOS. GLOBE, Mar. 29 2021, https://www.bostonglobe.com/2021/03/29/opinion/legislature-should-not-be-exempt-open-meeting-law/?p1=BGSearch_Overlay_Results ("The collective use of virtual meeting tools by so many Massachusetts residents has made it easier for residents of all ages to engage on issues they care about without having to drive to a hearing at city hall or hire a babysitter to attend a school committee meeting.").
[57] Americans with Disabilities Act of 1990, 42 U.S.C. § 12101 et seq. (1990).

hard of hearing. An ASL interpreter should be available for any persons in the audience requiring sign language translation. ASL and language interpreters should be providing real-time, live interpretation of the hearings, as opposed to reading and translating from a record.

The interpretation should be carried out as soon as the event begins. It is essential to maintain the quality of translation and interpretation services. We recommend a list of specific service agencies which project proponents may use to meet their needs and ensure the accuracy of translations and interpretation for public involvement. Subpar services such as an interpreter lacking the skills or technical knowledge needed to accurately capture the information causes significant inequities in public participation. Identifying language services providers with the technical knowledge needed to translate adequately is necessary to ensure the public's understanding of proposed activities and therefore the ability to provide feedback.

Interpreters should receive all presentation materials in advance and, as discussed above, must possess subject matter expertise in the areas of energy, energy infrastructure, permitting, siting, and utilities. All materials distributed or displayed at these meetings, including agenda, notes, and slide presentations, must be provided in all languages simultaneously.

Although pre-registration should be encouraged as a useful planning tool, people who have not pre-registered should not be precluded from commenting at public hearings, whether in person or remotely. Allowing members of the public increased flexibility to make comments despite prior pre-registration ensures equitable and robust public participation.[58]

Finally, the EDCs should maintain webpages that provide clear instructions for how the public can engage in process.[59] This webpage should include instructions for how to pre-register for participation in a public hearing along with accessibility resources.

Language Access

The EDCs should develop language access protocols[60] and ensure translation of public notices and for hearings wherever an impacted community includes a population that is more vulnerable to the adverse impacts of climate change or that has been historically burdened[61] by the energy infrastructure siting. Generally, these communities have high prevalence of BIPOC populations, low-income individuals and families, and limited English proficiency. Although environmental justice populations can be identified by recognizing that a portion of their members have limited English proficiency, this designation does not specify which language or languages are spoken in the community, so determining what languages a notice or proceeding must be translated into needs to occur on a case-by-case basis. The EDCs should use publicly available data so that the approach of determining which languages require translation is replicable and aligns with the

[58] SWG Report at 54.
[59] *See, e.g.*, *How to Participate at the Commission*, MAINE PUBLIC UTILITIES COMMISSION, https://www.maine.gov/mpuc/about/how_to_participate.shtml.
[60] SWG Report at 40.
[61] 88 FR 33240, 33413 (2023).

Massachusetts definitions of "environmental justice" and "environmental justice principles"[62].

To determine which and how many languages notices should be translated into, the EDCs should carefully consider which communities are impacted by the matter in question and determine the make-up of those communities and coordinate the simultaneous release of project documents in English and any necessary languages to ensure equal comment opportunities to limited English proficient residents.

Conclusion

We thank the GMAC and the EDCs for their efforts toward the Commonwealth's clean energy future. As noted in the 2050 CECP, aggressive electrification of buildings and transportation in Massachusetts is the most cost-effective means to achieving our GHG emissions reduction mandate. The increase in electric load and uptick in reliance on the electric grid to provide energy for our daily lives necessitates this thorough and timely review of the current state of the electric distribution system and what actions must be undertaken to ensure a clean, resilient, reliable, and affordable grid for the future. It is clear from the EDCs' ESMP filings that the time spent working through drafting with the GMAC has been fruitful, and we believe that with incorporation of the recommendations contained herein and continued engagement moving forward, the ESMPs will be strengthened for their filing at the DPU in 2024.

Thank you for your time and attention to these comments. Please reach out to Priya Gandbhir (pgandbhir@clf.org) for any additional discussion on the ESMPs and grid modernization in Massachusetts.

Very truly yours,

Priya Gandbhir, Senior Attorney, *Conservation Law Foundation*
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David Schreiber, Vice President, *Jewish Climate Action Network of Massachusetts*
Marcia Cooper, President, *Green Newton*
John R. Cook, Jr., *individually*

These comments were drafted and coordinated by Conservation Law Foundation.

[62] M.G.L. Ch. 30, § 62; *see also* Mass.gov, Executive Office of Energy and Environmental Affairs, *Environmental Justice Populations in Massachusetts*, available at https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts#what-isan-environmental-justice-population (last accessed 7/24/2023).

Graham Turk
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11/2/2023
To: MA-GMAC@mass.gov

Dear Commissioner Mahony & GMAC Members,

I am writing to comment on Eversource's Electric Sector Modernization Plan (ESMP). I am an Eversource customer and power systems researcher at Massachusetts Institute of Technology. Prior to my current role, I worked on the power supply and innovation teams at Green Mountain Power, an electric distribution utility in Vermont. I delivered a version of these comments during the second listening session on November 1, 2023.

Motivation
This concern comes from the fact that under today's rates, an average Massachusetts home will spend more money on heating and cooling after installing a heat pump system; this is a major deterrent to electrification and will prevent the state from meeting its climate targets. Excessive and unnecessary investment in the distribution grid (whose costs are recovered from all customers in rates) will place these goals even further out of reach.

Introduction
Eversource's ESMP systematically overlooks rate design and demand flexibility as alternatives to capital-intensive capacity upgrades. Their demand forecasts assume flat volumetric rates, which many states are transitioning away from because they are inefficient, regressive, and not cost-reflective. If approved, Eversource's plan will push millions of dollars of unnecessary spending onto Massachusetts grid users, increasing energy burdens and disincentivizing electrification.

Evidence for Rate Design's Effectiveness
Time-varying electricity rates, enabled by the deployment of advanced meters, provide opportunities for customers to reduce their costs by shifting demand to "off peak" hours when the grid is not congested. This is especially true for customers who adopt electric vehicles (EVs), which can be programmed to delay charging to later hours. EV charging is significantly more price-responsive than other household loads, and nudges alone are not enough to get EV owners to change their charging behavior (i.e., incentives are required).[1] Rate design is also an important tool for reducing the operating costs of heat pumps. Using actual metered data, Sergici et al. propose revenue neutral alternatives to flat volumetric rates that shift some of the cost recovery burden to non-volumetric charges (e.g. fixed and demand charges) and better reflect the underlying costs of generation and delivery.[2] At current gas prices and Eversource's

[1] Bailey et al., "Show Me the Money! Incentives and Nudges to Shift Electric Vehicle Charge Timing."
[2] Sergici et al., "Heat Pump–Friendly Cost-Based Rate Designs."

residential rates, below ~35F it is cheaper to burn gas than run a heat pump.[3] That gap must close if we want any hope of electrifying rapidly.

Time-varying rates are also effective at reducing peak demand. Under flat volumetric rates, customers receive no information or price signals about when the grid is constrained. In contrast, across 15 surveyed utility programs, critical peak pricing induced a drop in peak demand by 13-20%, climbing to 27-44% when rate design was accompanied with enabling technologies (e.g., smart thermostats and water heaters).[4] Furthermore, low income households responded to variable prices at the same level or higher than medium/high income households. The notion that only wealthy households will respond to time-varying prices is not supported by evidence.

For EV charging specifically, rates must be designed carefully. Simple volumetric time-of-use pricing (like Eversource's G-2 and G-3 rates) would produce large "rebound" peaks as a result of many residential EV chargers turning on in a synchronized manner.[5] Eversource's ESMP acknowledges this limitation:

> *"However, the activation of the start of the charging must be done carefully to avoid creating a new local peak. For example, a residential program that prevents charging from 3pm-8pm but allows all vehicles to begin charging at full speed at 8pm would result in higher total system peaks than if each car had simply begun charging when it arrived home -- see the modeling presented in Section 8.1.3" (p. 459).*

While Eversource claims that passive programs are "not effective mechanisms to manage real time locational grid congestion constraints" (p. 458), this is based on the incorrect assumption that volumetric time-of-use rates are the only option. Many utilities have implemented alternatives including residential demand charges, capacity subscriptions, and offset time-of-use windows. A demand charge rate that encourages EV owners to spread charging over nighttime hours (rather than charge at full power when vehicles arrive at home) yields a significant reduction in peak demand.[6]

Advanced metering will be ubiquitous in Massachusetts by the end of this decade, and there is no reason not to transition eligible customers to smarter rates as soon as possible. While a transition to time-varying rates would inevitably create winners and losers in the near term compared to flat volumetric rates, in the long term all customers will benefit from the deferral or elimination of costly grid upgrades. Eversource states, "prior experience indicates that not all customers will respond to price signals," (p. 281), but not all customers need to respond to achieve meaningful peak demand reductions across one or many distribution feeders. These rates should be the default for all residential customers, with the ability to opt-out. At the very

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[3] Michaels and Nachtrieb, "Transitioning to Heat Pumps in Cold Climates: A Systems Dynamics Analysis."
[4] Faruqui and Sergici, "Household Response to Dynamic Pricing of Electricity."
[5] Muratori and Rizzoni, "Residential Demand Response."
[6] Gschwendtner, Knoeri, and Stephan, "Mind the Goal."

least, Eversource should conduct a sensitivity analysis on peak demand under various time-varying rates.

Other Gaps in Eversource's ESMP

Besides the general omission of time-varying rates in their load modeling, I would like to highlight a few other parts of Eversource's ESMP that I found problematic. For each, I provide a direct quote from the ESMP followed by my critique:

> *"The Company has explored other mechanisms to manage electric demand reductions but finds some specific applications such as Electrification Heating Demand Response as difficult to yield tangible demand reductions sufficient to defer or avoid necessary grid upgrades." (p. 10)*

While it may be true that heating is less flexible than other loads (like EV charging), this is not a valid reason to omit modeling thermostatic demand response entirely. Utility programs to cycle or temporarily adjust HVAC equipment have proven highly effective for decades.

> *"The savings from the Mass Save active demand response programs (see section 6.1.9) is currently not explicitly included in the Company's forecasts. The Mass Save programs have an "Opt-Out" capability, such that customers may simply decide not to reduce load on a given day. Therefore, the Company does not treat new Active Demand Response program enrollments as a firm capacity resource that could result in the reliable reduction in peak demand necessary to displace a traditional distribution asset, because the actual performance of the customer cannot be ensured."*

The fact that individual customers can opt out of individual events does not mean that active demand response programs are unreliable in aggregate. Probabilistic models can be developed that predict (with high likelihood) the level of demand response from an aggregation of buildings, which can be used for long-term peak demand planning and real-time operations. In fact, diverse aggregations may even be *more* reliable than traditional distribution assets, which are single points of failure. Considering that ISO New England's forward capacity auction allows for active demand response resources, I struggle to understand Eversource's choice to exclude them entirely from their demand model.

> *"Currently, the default technology for residential sites selected for heating conversion is assumed to be an air source heat pump. The reference electric heating load is based on the heating design capacity at the design day temperature and coefficient of performance (COP). The reference electric heating design load assumed is 5 kW per residential heat pump customer for an average house size of approximately 2,000 sq. ft. in Massachusetts and seasonal COP of 2.34 and a floor COP of 2."*

This modeling assumption is misaligned with a recent Cadmus study on heat pumps in the northeast, which found that even a whole home heat pump system (with no primary backup) had a coincident winter peak demand of 1.03 kW per 1000 square feet.[7] Eversource's ESMP also includes a sensitivity analysis on hybrid heating systems (which would switch from electric to backup fossil heat below a certain temperature setpoint) but does not include this in demand forecasts. Because Eversource is a gas and electric utility, they are in a strong position to develop new business models around hybrid heating solutions, which would cut emissions while reducing the need to build excess distribution and transmission capacity. For example, they could install integrated thermostats that switch from electric to backup fossil heat when the temperature is below a pre-specified threshold, helping to mitigate heating-driven winter peak demand. Another alternative would be to transition entire neighborhoods to electric heating (potentially with backup battery storage) rather than upgrading old gas pipeline infrastructure.

> *"An unknown quantity to date of peak demand impacts is likely to be gained from intelligent rate design (See Section 9.7.2) which incentives customers to control, much like most commercial customers today, their peak demand" (p. 475).*
>
> *"With customers adopting more and more electrified technologies into their life (EV, Heating, Induction Stoves) in addition to high load units such as dryers, it will become increasingly more important to incentivize specific behaviors to help minimize the system load (See Section 9.7.2 on potential rate components which might incentivize such behavior" (p. 477).*
>
> *"For example, a residential program that prevents charging from 3pm-8pm but allows all vehicles to begin charging at full speed at 8pm would result in higher total system peaks than if each car had simply begun charging when it arrived home -- see the modeling presented in Section 8.1.3" (p. 459).*

Sections 9.7.2 and 8.1.3 do not exist in the draft ESMP. Given these sections' apparent relevance to the role of rate design, which was not modeled elsewhere, I was curious to see the results.

Conclusion

To meet Massachusetts' decarbonization targets, we must look beyond traditional approaches. Proven tools like rate design and demand management will help avoid expensive capital investments, which in turn will make electrification more attractive and decrease energy burdens.

To achieve those aims, I recommend that the GMAC request the following from Eversource in the next round of ESMP drafting:

- Model load profiles under alternative rate designs, including time of use, demand/subscription charge, and critical peak pricing
- Model active demand management as a firm capacity resource for peak reduction
- Investigate how to collect a portion of embedded network costs through fixed or connection charges to reduce volumetric charges

[7] Veilleux, "Residential ccASHP Building Electrification Study."

- Include a load duration curve that illustrates how many hours per year of active demand management would be needed to reduce system peak demand by 5%, 10%, and 20%
- Use heating demand profiles that consider hybrid heating solutions at different setback temperatures
- Propose EV-specific rates that receive data from a charger or vehicle (and do not require AMI meters), similar to what they have already implemented in Connecticut[8]
- Include chapter and section number in the header or footer of each page to make the document easier to navigate

Thank you for the opportunity to comment and I look forward to staying involved.

Sincerely,

Graham Turk

References

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8 https://www.eversource.com/content/residential/save-money-energy/clean-energy-options/electric-vehicles/ev-charger-managed-charging/ct

Leslie Zebrowitz, Co-Chair of Newton EV Task Force, (evtaskforcenewton@gmail.com) – Received 11/3/23.

You probably are already aware of this, but I want to urge you to seriously consider emulating Vermont's approach.

https://environmentamerica.org/updates/vermont-utility-proposes-to-install-battery-storage-in-most-homes/

Thank you.

Leslie Zebrowitz, Co-Chair

Newton EV Task Force

STACK ENERGY
CONSULTING

November 6, 2023

Grid Modernization Advisory Council
100 Cambridge St, 9th Floor
Boston, MA 02114

Re: NRG Energy, Inc. Comments on Electric Sector Modernization Plans

Dear Commissioner Mahony and Grid Modernization Advisory Councilors:

NRG Energy, Inc. ("NRG") appreciates the Council's work on the Electric Sector Modernization Plans ("ESMPs") and the transparency with which the Council is operating. We thank the Council for the opportunity to provide comments.

As licensed competitive, retail energy suppliers, the NRG Retail Companies[1] provide competitive electric generation supply as well as other energy-related products and services to residential and non-residential customers in the Massachusetts competitive retail market. Moreover, the NRG Retail Companies provide competitive electric generation supply to 22 Massachusetts cities and towns consistent with municipal aggregation plans approved by the Department of Public Utilities ("DPU").

In this capacity, the NRG Retail Companies are keenly interested in seeing that customers reap the operational and financial benefits of the Department's grid modernization initiatives, and the benefits of advanced metering infrastructure ("AMI"), as soon as possible.

To achieve this outcome, the Grid Modernization Advisory Council ("GMAC") should provide feedback on the following four areas to the Electric Distribution Companies ("EDCs") on their ESMPs:

1. The EDCs should develop a statewide uniform data access protocol as soon as possible so that customers benefit from AMI once the EDCs deploy it on their premises

2. To ensure AMI delivers the benefits that are justifying ratepayer investment, the protocol should:
    - Ensure that customer loads are settled using AMI data on a granular interval, rather than continuing to use load profiles for settlement
    - Enable the bulk transfer of expanded customer usage data available through AMI
    - Similar to New Hampshire and New York, Include a statewide data repository with comprehensive datasets (e.g., electric/gas usage, rate information) and streamlined access for consumers and their retail suppliers

[1] NRG's retail electric supplier subsidiaries licensed by the Massachusetts Department of Public Utilities include Direct Energy Business, LLC; Direct Energy Services, LLC; Energy Plus Holdings, LLC; Green Mountain Energy Company, Inc.; NRG Home f/k/a Reliant Energy Northeast LLC; and XOOM Energy Massachusetts, LLC. For purposes of these comments, the licensed subsidiaries will be referred to collectively as the "NRG Retail Companies".

- To stimulate participation in demand response programs and real-time behavior change, enable customers and their designated energy provider to access data directly (and in near real-time) from the customer meter in an open, non-discriminatory fashion.

3. The EDCs should implement Time-Varying-Rates on a default, opt-out basis for all basic service customers as soon as practical and implement robust customer education campaigns to maximize TVR participation and impact.

4. The EDCs, the DPU, the Department of Energy Resources ("DOER") and Council should seek to empower customers to control more of their energy bill. This includes but is not limited to collaborating with ISO-NE to reduce transmission costs.

NRG expands on each of these four recommendations below.

1. **Recommendation #1: The EDCs should develop a statewide uniform data access protocol as soon as possible so that customers benefit from AMI once the EDCs deploy it on their premises**

NRG appreciates that the AMI Working Group is actively discussing the statewide data access protocol. Still, it will take several years for the EDCs to implement the protocol, for suppliers to build the front-end customer interface to enable customer engagement, and for EDCs and suppliers to educate customers. On Slide 10 of the EDC's AMI Working Group presentation from October 31, under the category of when "aggregated data" will be available, the EDCs proposed to "ensure functionality is ready when AMI deployment is substantially complete." The Council should recommend to the EDCs that they be ready to share aggregated data immediately following AMI installation to an aggregation. For example, once everyone in a municipality has AMI, customers and competitive suppliers in that municipality should be able to access the data.

The time immediately following deployment is critical for engaging customers. If customers see no benefit from AMI until two-three years after the AMI is deployed at their premises, they are far less likely to engage in their energy usage. A guiding principle should be for customers and their competitive suppliers/aggregators to have access to AMI data nearly immediately following deployment at their premises.

Therefore, to ensure consumers and retail suppliers can access data immediately after the EDCs deploy AMI, EDCs and stakeholders should seek to finalize the protocol as soon as possible.[2]

[2] NRG supports the comments made by DOER in their June 29 submission to the GMAC:

"The EDCs should include a description of what a uniform statewide data access strategy and process might look like for the Commonwealth. Examples include New York, which has a Distribution System Data Portal that transparently displays the utility system capabilities, needs, limitations, and opportunities for DERs, and developing plans in New Hampshire."

Recommendation #2: To ensure AMI delivers the benefits that are justifying the ratepayer investment, the Council should recommend that the statewide protocol:

A. Ensure that customer loads are settled using AMI data on a granular interval, rather than continuing to use load profiles for settlement

The value of AMI for customer demand response resides in being able to measure and bill a customer's supplier based on that customer's actual consumption over time. Not doing so, and instead relying on a hypothetical load profile, will cause a customer who has a different load shape because of demand response to have their efforts go unacknowledged in terms of reduced costs of energy, capacity, and transmission. Consequently, and at a minimum, the roll-out of AMI should ensure this core functionality is turned 'on' for the purposes of settlement.

B. Enables the bulk transfer of expanded customer usage data available through AMI, including on an opt-out basis for municipal aggregations

Green Button Connect My Data ("GBC:MD") is well-suited for providing individual customers with access to their own usage data. However, for competitive retail suppliers or aggregators that are routinely downloading thousands or tens of thousands of customer datasets, GBC:MD is not viable for obtaining their customers' billing quality data. Therefore, the Council should recommend that the EDCs enable bulk transfers of AMI data to competitive retail suppliers and aggregators through an alternative mechanism to GBC:MD. This could include but not be limited to Electronic Data Interchange ("EDI"). For municipal aggregations where customers were already enrolled on an opt-out basis, this data should be provided on an opt-out basis. NRG supports the EDC proposal on Slide 11 of their October 31 presentation to the AMI WG that said, "consent not required if number of unaffiliated customers in aggregation exceeds 100."

EDCs already transfer bulk data today that is not AMI, so this is extending that practice to AMI.

C. Includes a statewide data repository with comprehensive datasets (e.g., electric/gas usage, rate information) and streamlined access for consumers and their retail suppliers

New York and New Hampshire are both implementing statewide data repositories with centralized data access. Given National Grid's and Eversource's presence in each of these states, they can leverage their learnings to develop a statewide repository in MA. Consumers, utilities, retail suppliers, and others could realize efficiencies from the implementation of repositories in multiple states (e.g., vendor pricing, similar requirements, APIs).

To ensure that the repository includes comprehensive information, the Council should recommend that the EDCs in MA use the "Logical Data Model" that stakeholders agreed to in the settlement of Docket No. DE 19-197 in New Hampshire.[3] Among other important datasets, the "Logical Data Model" includes

[3] Please see Appendix B of the Settlement Agreement in Docket No. DE 19-197. State Of New Hampshire. Before The Public Utilities Commission. Electric And Natural Gas Utilities. Development Of a Statewide, Multi-Use Online Energy Data Platform.

both electric and gas usage, as well as the customer's rate. This enables competitive suppliers and aggregators to tailor offerings that match a customer's profile. In their October 31, 2023, presentation to the AMI Working Group, the EDCs excluded data categories included in the "Logical Data Model," including rate information. Consumers in MA should have access to the same data categories available to consumers in NH.

Regarding customer authorizations, in non-aggregation situations, customers should not have to endure the hassle of authorizing competitive suppliers to access their data in the central repository if they have previously provided authorization to competitive suppliers to access their usage data. This will help streamline access.

D. Grant customers and their designated energy providers the ability to access data directly (and in near real-time) from the customer meter in an open, non-discriminatory fashion. This is necessary to stimulate participation in demand response programs and real-time behavior change.

While a statewide repository is valuable for billing purposes and customers settlements, data will not be available in the repository with the necessary latency (i.e., time between the customer uses the energy and when that data is visible) to enable certain applications. For instance, real-time price alerts, demand response, and demand charge management often require changing behavior within seconds or minutes. Slide 10 of the EDCs October 31 AMI WG presentation proposes making data available the next day for individual customers and the next month for aggregated customers.

To enable real-time behavior change and demand response participation, the Council should recommend that with the proper customer authorization, the EDCs provide direct access to near real-time meter data to customers and their competitive suppliers/aggregators in an open, non-discriminatory manner.

This requires that meters meet IEEE 2030.5 standards and utilize the Home Area Network ("HAN") function that is preloaded on the meter with specific functions for the sharing of data with an interval of one second or greater. The Council should recommend that the EDCs include in their ESMPs the key provisions in a recent settlement agreement reached in Colorado between Xcel Colorado, Colorado PUC trial staff, and stakeholders. Specifically, Section II, titled "HAN Deployment and Data Rules" of the Settlement Agreement stated:

"The Settling Parties agree that development and deployment of the HAN functionality of the Advanced Meters in an open, non-discriminatory manner (as described below) is in the public interest. Customers' easy access to their energy usage is in the public interest."[4]

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[4] Before The Public Utilities Commission of The State of Colorado. In The Matter of The Application Of Public Service Company of Colorado For Approval to Amend The Certificate Of Public Convenience And Necessity For Its Advanced Grid Intelligence And Security (AGIS) Initiative. Proceeding No. 21a-0279e. Unanimous Comprehensive Settlement Agreement. The Unanimous Comprehensive Settlement Agreement ("Settlement Agreement" or "Agreement") was entered into by Public Service Company of Colorado ("Public Service" or the "Company"), Trial Staff ("Staff") of the Colorado Public Utilities Commission ("Commission"), the Office of the Utility Consumer Advocate ("UCA"), Mission:Data Coalition, Inc. ("Mission:Data"), Western Resource Advocates

Recommendation #3: **The EDCs should implement Time-Varying-Rates ("TVRs") on a default, opt-out basis for all basic service customers as soon as practical and implement robust customer education campaigns to maximize TVR participation and impact.**

The EDCs have differing proposals on TVRs in their ESMPs. National Grid proposes pilots in 2026-2027 prior to large-scale rollout and opt-in rates for interested customers beginning in 2028. Eversource appears to only be considering TVRs after full AMI deployment and on an "optional" basis, which NRG assumes means "opt-in."[5]

As detailed by the Brattle Group, opt-in TVR rates lead to significantly lower customer participation in TVRs compared to default rates, with opt-in participation reported as less than 2%. [6][7] If TVRs are exclusively offered in Basic Service on an opt-in basis, Massachusetts policymakers should expect an underwhelming level of participation.

NRG believes that Basic Service should be more reflective of the underlying fundamentals of wholesale costs, which augurs in favor of a default rate structure that is time-varying. Several states have transitioned to opt-out time varying rates for utility default service, including California, Colorado, Michigan, and Missouri.[8]

In the study referenced above, Brattle provides examples of TVRs saving customers from 8%-20% on their energy bill and driving steep peak demand reductions. Brattle also highlights that states, including California, have implemented consumer protections coincident with the deployment of opt-out TVR.

Given the ability for TVRs to reduce customers money and drive down peak demand, utilities should offer TVRs on an opt-out default basis as soon as possible (i.e., no later than 12 months after a customer receives AMI on their premises) and implement robust customer education campaigns to maximize participation and impact.

Recommendation #4: The EDCs, the DPU, the Department of Energy Resources ("DOER") and Council should seek to empower customers to control more of their energy bill. This includes but is not limited to collaborating with ISO-NE to reduce transmission costs.

In New England, capacity and transmission are billed based on coincident peak demand billing determinants. To maximize the benefits of TVRs, customers and their suppliers must be granted the ability to reduce their usage at these hours in which those billing determinants apply, and thus reduce

("WRA"), Utilidata, Inc. ("Utilidata"), Itron, Inc. ("Itron"), the Colorado Solar and Storage Association ("COSSA"), and the Solar Energy Industries Association ("SEIA") (collectively the "Settling Parties")

[5] Page 293 of the Eversource ESMP states "Access to usage information, insights, alerts, and availability of optional time-varying rates, for instance, will provide customers with new opportunities to manage energy consumption and lower bills."

[6] Moving Ahead with Time-Varying Rates (TVR) - US and Global Perspectives (brattle.com). See Slide 2.

[7] An emerging push for time-of-use rates sparks new debates about customer and grid impacts | Utility Dive. An emerging push for time-of-use rates sparks new debates about customer and grid impacts | Utility Dive. Jan 28, 2019. Citing Brattle Principal Ahmad Faruqui, the article stated, "About half of U.S. investor-owned utilities have optional time varying rates for residential customers," he said. New programs are being tested or talked about in at least ten states, but at present only 1.7% of all residential customers have chosen to use them.

[8] Cooper and Shuster, "Electric Company Smart Meter Deployments: Foundation for a Smart Grid," Institute for Electric Innovation, April 2021, p. 3.

their cost exposure not just to the cost of energy but to the capacity and transmission services of ISO-NE as well. By allowing customers to manage their entire energy bill, the peak to off-peak ratios in the TVRs will increase, resulting in higher net benefits to all consumers. In the previously referenced presentation, Brattle noted that “On average, residential customers reduce their on-peak usage by 6.5% for every 10% increase in the peak-to-off-peak price ratio.” This reduction has a direct impact on the capacity and transmission costs allocated to those customers’ suppliers.

One area ripe for customer savings is transmission-related costs, which have spiked to over $145,000/MW-yr. in ISO-NE and represented over 35% of total wholesale costs in August of 2023.[9] Most Massachusetts customers have no recourse for managing this 35% of their bill and TVRs must include the ability for customers to reduce their transmission costs. Suppliers should have the ability to be faced with these charges and to have settlements for them occur at the customer level, thus conveying an incentive for suppliers to offer demand-response retail products to customers that optimize around reducing transmission and capacity costs that are demand-related. For Basic Service TVR, meanwhile, those costs should be allocated to the on-peak price interval.

Beyond cost allocation, all customers in MA could reap benefits if ISO-NE incorporated TVR-induced load reductions into their transmission planning process, which could lead to deferrals in transmission build. NRG is aware of the ability for certain large customer classes to reduce their transmission cost allocation today, so extending this aspect of rate design to other customer classes would allow an equitable basis for customer responsiveness to transmission pricing which, today, is only open to larger customers who, by responding, are arguably able to shift transmission costs onto the residential customer class.

Therefore, the Council should recommend that the EDCs include the ability for customers to manage their entire energy bill in TVRs, that suppliers can monetize avoided costs around ISO-NE demand-related charges, and that the DPU, DOER, EDCs, and Council collaborate with ISO-NE to ensure that these TVRs are factored into transmission planning.

Conclusion

NRG thanks the GMAC for your consideration of these comments. By adopting the recommendations above, the GMAC can enable Massachusetts consumers to realize the benefits of AMI. Please contact Greg Geller (contact information below) with any questions.

Sincerely,

Respectfully submitted on behalf of NRG Energy, Inc. by Greg Geller
CEO, Stack Energy Consulting
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W: Stack Energy Consulting

[9] 2023_08_nlcr_final.pdf (iso-ne.com). See Table 3-1 of ISO-NE Monthly Regional Network Load Cost Report August 2023. Prepared on October 20, 2023.

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November 7, 2023

Re: Comments on Draft Electric Sector Modernization Plan of Eversource Energy

Dear Commissioner Mahony and Grid Modernization Advisory Council Members,

The towns of Aquinnah, Barnstable, Bourne, Brewster, Chatham, Chilmark, Dennis, Edgartown, Eastham, Falmouth, Harwich, Mashpee, Oak Bluffs, Orleans, Provincetown, Sandwich, Tisbury, Truro, West Tisbury, Wellfleet and Yarmouth, and Dukes County, organized and operating collectively as the Cape Light Compact JPE, a joint powers entity pursuant to G.L. c. 40, §4A ½ and G.L. c. 164, §134 (the "Compact"), submit to the Grid Modernization Advisory Council ("GMAC") the following comments on the Draft Electric Sector Modernization Plans ("Draft ESMPs") submitted by Eversource Energy ("Eversource") and the other electric distribution companies (collectively, the "EDCs") on September 1, 2023. The Compact is the municipal aggregator and energy efficiency program administrator on Cape Cod and Martha's Vineyard. Eversource is the EDC in the Compact's service territory so these comments are primarily related to Eversource's Draft ESMP.

1. Pursuant to G.L. c. 164, §§ 92B-92C, the Climate Act required, among other things, the GMAC to "encourage least-cost investments in the electric distribution systems," and to review and provide recommendations on the ESMPs that "maximize net customer benefits and demonstrate cost-effective investments in the distribution grid," minimize or mitigate impacts on ratepayers, and reduce impacts on and provide benefits to low-income ratepayers. Eversource's Draft ESMP was filed with the GMAC without costs, bill impacts, a net benefits assessment, and – at least initially – metrics. It is difficult to evaluate the proposals, in particular alternatives, in such isolation and does not seem possible for the GMAC to fully undertake its statutory review. The GMAC recommendations should expressly note that the GMAC did not have the benefit of this information to evaluate the Draft ESMP, and should ask that the DPU direct in its orders on these ESMPs that future Draft ESMPs must be accompanied by this information on the initial filing date.

2. Eversource's Draft ESMP largely recounts existing projects or proposals such as grid modernization investments or the capital investment projects ("CIPs") pending with the Department. The Compact was hoping for more creativity in the Draft ESMP and – in particular – use of municipal aggregations. Meeting the 2050 climate goals largely through infrastructure upgrades and new facilities is one approach. But as recognized in GMAC recommendations, non-wire alternatives, demand response, and storage solutions have not received nearly enough attention. Beyond even that though, Eversource should tap into targeted partnerships to find creative solutions for system constraints. For example, certain areas and facilities on Cape Cod and Martha's Vineyard could be excellent candidates for microgrids. Significant investments are being made by municipalities in wastewater

treatment facilities that are designed to be resilient and energy efficient, include clean energy assets, and – with program support including clarity regarding ownership of and access to electric grid assets – could be deployed as multi-user microgrids. Eversource and the Compact are currently collaborating on a potential grant opportunity for a microgrid. However, the Compact would like to ensure that these kinds of projects happen regardless of available grant funding.

3. The Compact is the energy efficiency program administrator on Cape Cod and Martha's Vineyard – where Eversource is the EDC and National Grid provides gas service for some Compact customers. Eversource's Draft ESMP notes the Compact's role, but the plan does not mention working in partnership with the Compact to bring about demand response and least-cost alternatives, nor having the Compact participate as part of the newly proposed Joint Utility Planning Working Group discussed in Section 11. The Compact respectfully requests that the Eversource ESMP be revised to include collaboration with the Compact in non-wire alternatives, demand response, and storage solutions.

   The Department of Energy Resources ("DOER") recommended that the EDCs should "identify initial potential locations for pilot programs to start the transition from gas to electric in their overlapping gas and electric service territories." Recommendation #114 (October 26, 2023). The Compact would welcome integrated planning with the EDCs and participation in pilots to develop targeted programs to assist with meeting the Commonwealth's climate goals. In addition, the Compact agrees with DOER's recommendations that Eversource should "provide more detail on demand management programs and how it will reduce peak load in the 2035-2050 timeframe. See Recommendation #80 (October 26, 2023).

4. Eversource's Draft ESMP shines a spotlight on the pressing need for approval of Eversource's pending CIPs, including the Cape CIP in Docket D.P.U. 22-55. These projects provide the foundation for Eversource to move forward with and remove barriers to DER interconnections. The Compact urges swift approval of the pending CIPs by the Department.

5. The Compact encourages the GMAC to take into account significant differences between the EDCs' Draft ESMPs in its recommendations. It is crucial that disparities between the EDCs be contended with prior to the DPU filings. For example, all EDCs should adopt the new opportunities for storage developers and customers, including rate redesign specific to behind the meter energy storage. See National Grid Draft ESMP at 74.

6. The Compact supports GMAC recommendations calling for the EDCs to have a strategy in their ESMPs to implement time-varying rates ("TVR") with the roll out of advanced metering and to begin customer education prior to completion of that roll out. See Recommendations 55 and 60 (October 12, 2023). The plan should also include how the EDCs will enable third parties, such as the 168 municipal aggregators operating in Massachusetts, to offer meaningful TVR – including utility billing for critical peak pricing TVR.

   In addition, TVR offered by third parties will require data access, which should also be covered in the ESMP. As discussed in DOER's Comments to the GMAC (dated June 29, 2023), the ESMPs should include "a description of what a uniform statewide data access strategy and process might look like for the Commonwealth."

7. Finally, the Compact has two clarifications for the Eversource ESMP:

    (A) The Draft ESMP refers to the New Bedford Industrial Park Battery Storage System on page 352. The ESMP should clarify whether that storage system will be used for peak shaving.

    (B) The Draft ESMP notes Eversource's asset health model for poles on page 103. That model should include the number of double poles in its service territory. The number of double poles on Cape Cod and Martha's Vineyard have continued to increase resulting in safety concerns and aesthetic eyesores. The ESMP should report the number of double poles and the plan to decrease them.

The Compact appreciates the opportunity to provide feedback.

Submitted by:

Margaret T. Downey, Administrator

City of Boston
Environment

November 13, 2023

Commissioner Mahony
Department of Energy Resources
100 Cambridge Street, #1020
Boston, MA 02114

By Electronic Submission to MA-GMAC@mass.gov

Re: Comments on Electric Sector Modernization Plan Draft Proposed Structure

Commissioner Mahony and Grid Modernization Advisory Council Members,

We are pleased to see the grid modernization proceedings moving forward and appreciate the extensive analysis and planning work being done by the Electric Distribution Companies (EDCs) and Grid Modernization Advisory Council (GMAC). We are already late to envisioning the energy system we will need going forward to achieve our climate change mitigation plans - we need to be building that system now and limiting new investment in fossil fuel systems that will become stranded assets. Dramatically reducing greenhouse gas (GHG) emissions, including from our building and transportation sectors, will require a significant increase in the availability and distribution of clean energy. Such growth needs to be accompanied by measures that limit the need for new infrastructure and implemented in a manner that supports equitable electrification.

The grid modernization proceedings are important to support both our long-term decarbonization goals and ongoing municipal initiatives to advance equitable electrification that provides reliable, resilient and affordable clean energy to residents most in need. The Commonwealth's 2030 emissions targets are coming up fast, and municipalities like the City of Boston are already exploring many of the ideas discussed in the grid modernization plans; we need these plans to translate quickly into action.

The value of this planning process will depend in part on the speed of follow-up action. As such, the electric sector modernization plans (ESMPs), GMAC's recommendations and the Department of Public Utilities' (DPU) orders should include directions to utilities to move forward with implementation, including via exploring new models for partnering with, or supporting initiatives by, municipalities and private parties. For instance, where relevant, utilities should engage in and support pilot projects before or while the DPU conducts further investigations. Where DPU or utilities do not have the authority to direct or undertake actions recommended by the plans, such gaps should be identified now so that we can seek clarification and/or necessary changes from DPU or the Legislature.

This letter presents, in Section I, three principles that should guide the development, review and implementation of the plans. In brief, these principles relate to: (i) reducing the need for new infrastructure through the use of non-wire alternatives and distributed energy resources; (ii) advancing equitable electrification that considers the distribution of benefits and impacts from innovative approaches and new large infrastructure; and (iii) prioritize deployment of and support for innovative solutions, partnerships, and financing mechanisms, including with municipalities and private parties.

While Section II of the letter provides examples of measures or initiatives that should be pursued to advance these principles, this letter does not attempt to address all aspects of the ESMPs. We look forward to continued opportunities to engage with the utilities, GMAC and the DPU as we move forward in evolving the electric system to support our decarbonization goals in an equitable and efficient manner.

I. Principles to Guide the Grid Modernization Proceedings

We recognize that implementing the principles discussed herein will require work beyond the ESMPs, such as additional dockets by the DPU and, perhaps at times, new authority from the Legislature. However, given that the ESMPs are designed to be a building block for future analysis and decisions, it is important that they include relevant data and ideas to reflect these principles.

A. Reduce the need for new infrastructure through the use of non-wire alternatives and distributed energy resources.

The plans forecast a significant growth in net electric demand, particularly in the Boston metro area, and indicate that existing substations will not be able to meet this demand from a capacity and/or reliability perspective (*e.g.,* Eversource ESMP pgs. 187, 219, 308-09). While the scale of current and projected electric demands makes clear that we will need more electric infrastructure, we should continue to pursue all reasonable and viable opportunities to reduce the amount of new infrastructure that will be required, through both non-wire alternatives (NWA) and distributed energy resources (DER).

NWA and DER measures can serve both as a bridge to future electrification and as a long-term solution. For instance, Eversource's plan to deploy a battery energy storage system (BESS) in support of the Hyde Park substation in Boston is proposed as an interim measure to address capacity until a new substation is built, while Eversource's BESS-powered microgrid in Provincetown provides a long-term resilience solution in lieu of constructing 13 miles of distribution lines. NWA and DER opportunities should be evaluated as both temporary and permanent alternatives to capacity investments, including a specific analysis regarding the ability to reduce peak loads and delay or reduce the need for building out transmission infrastructure.

The City understands that new bulk substations and associated infrastructure will be needed to accommodate the load growth that electrification of buildings and transportation will bring. But it is important that residents and businesses believe that EDCs, the DPU and the City are doing all that we can to alleviate the need for and sizing of these infrastructure upgrades. Public access to the EDCs forecasting and capacity data and modeling tools will help residents and businesses, and the organizations that represent them, assess and understand the role of NWA and DER and the need for new infrastructure.

B. Promote equitable electrification through the distribution of the benefits and impacts of modernizing the grid

Equity in the context of the energy system requires assessing both (i) access to sufficient affordable electricity to meet reliability and environmental objectives and (ii) the distribution of the benefits and burdens of the infrastructure that provides the electricity. This assessment needs to happen at both municipal and smaller neighborhood levels, which underscores the importance of having accurate data about capacity for DER and new electric loads at both the substation and feeder levels.[1]

Through the lens of equitable electrification, the City is exploring ways to use renewable energy and other NWAs and DERS to enhance the resilience of neighborhoods to extreme temperature and weather events. This could include the development of resilience nodes, whereby we strategically promote combinations of smart systems, demand response programs, and distributed solar and storage systems within specific neighborhoods to support critical facilities and keep community lifelines operating during power outages, *e.g.,* emergency services, food and water distribution, and community cooling or heating centers. Such programs can help respond to high prices and grid constraints, both as a short-term solution and to reduce the size of required upgrades to the grid. Based on the City's analysis of needs and opportunities, we can engage with communities and private developers to create such nodes. Access to the EDC's capacity and forecasting models and data supports these initiatives.

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[1] While these comments focus on the distributive aspect of equity, we also fully endorse enhancing procedural equity, including, as noted above, by providing the public greater access to forecasting and capacity data and models.

We echo the GMAC's recommendation that the ESMPs should discuss how NWAs, including energy efficiency, DERs and other technologies are acting to reduce load currently, and how they can continue to act as a bridge to and/or reduce the size of future infrastructure.[2]

C. Prioritize deployment of and support for innovative solutions, partnerships and financing mechanisms, including with municipalities and private parties.

Meeting our GHG emission reduction targets will require more than new infrastructure; it will also require integrating new technologies and revising models for siting, owning, operating and financing our electricity systems. These are complicated questions and there will not be a one-size-fits all solution. For instance, different approaches may be needed to support electrification in affordable housing versus large scale commercial or industrial development. But we cannot wait until we have complete answers to act. We must explore opportunities now, including through pilot projects and shadow programs, and remove barriers to forward-looking work by EDCs, municipalities and private parties.

While the ESMPs include some discussion of pilot projects,[3] there should be additional focus on making sure that the EDCs are positioned to take action early and explore new models for delivering service in ways that protect consumers. (We recognize that some pilots may be occurring through other dockets but believe those should be cross-referenced in the ESMPs for full context.) The pilot projects for utility-owned networked geothermal systems are an example of a model for early action that allows utilities and consumers to explore new technologies while we develop parameters for more large-scale deployment.

The table below includes specific recommendations for pilot projects, shadow programs[4] and/or near-term studies around issues such as, interconnections, microgrids, virtual power plants, ownership programs for solar on small low-income housing, alternative rates for low-income heat pump consumers, and financing mechanisms for building-specific infrastructure required to electrify. To support such initiatives going forward, we encourage the EDCs and DPU to integrate "smart" technologies, such as meters and inverters, into new infrastructure and to assess where upgrades to existing systems are needed for significant NWA and DER undertakings.

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[2] We also encourage ESMPS to assess the total greenhouse gas emissions, including from embodied carbon, that NWAs and DERs can avoid by reducing demand for new infrastructure.

[3] *See e.g.,* National Grid ESMP pages 15, 39, 74, 305, 307 and Eversource ESMP pages 281, 282, 283.

[4] We use the term shadow program to refer to a pilot project without direct impacts. For example, rather than directly apply time varying rates, a shadow program could install the technology needed for time varying rates and measure what the bills *would* be if time varying rates were assessed, but continue to charge consumers regular rates. An alternative format would be to charge the time varying rate but use general ratepayer funds to assure that protected consumers do not lose money, either at all or beyond a specified percentage.

II. Examples of Measures that the ESMPs Should Consider

The table at the end of this section outlines examples of measures that could advance some or all of the principles listed above and for which the ESMPs should build a base for moving forward with pilots and/or broader implementation. Many of these align with recommendations from the GMAC and with initiatives that are already being explored by municipalities and other state programs. Action by the EDCs and/or DPU is in some cases necessary to support or allow important local programs: the deployment of microgrids is an example.

Microgrids are a key tool in reducing peak energy load and increasing resilience and, particularly when paired with non-emitting energy sources and storage capacity, can advance the principles discussed above. The benefits of a virtual microgrid in Chinatown, a neighborhood with high levels of air pollution and heat island impacts, are described by its developers as "provid[ing] local residents with control over their own energy generation, new jobs, revenues and savings, and climate resilience."[5] The City has been working for some time to support the deployment of microgrids. For example, a 2016 "Boston Community Energy Study" assessed where throughout Boston microgrids were most feasible, and the Boston Smart Utilities program recently hired a microgrid design expert to help develop microgrid-ready building guidelines that would expand the City's capacity for microgrids. The City has also explored various ownership and operation models for microgrids and the legal parameters for multi-party systems.

As important as microgrids can be, and despite growing interest in these systems, there is little discussion of microgrids in the ESMPs. The plans and DPU should address issues such as (i) how the EDCs will activate microgrids, or in the case of an individual building, a nanogrid, (ii) the relationship between third-party and utility ownership and operation of various components of a microgrid and (iii) the ability for private parties to run electric lines across public ways without utility consent. The ESMPs should address the issues associated with a growing use of microgrids and the DPU should open a microgrids docket to assess how electric utilities can integrate islandable localized energy generation with its other grid operations and whether statutory changes are needed to support deployment of microgrids. While such a docket is pending, DPU should order/authorize the EDCs to undertake demonstration projects; should that happen, Boston has a microgrid project that is ready to implement.

[5] https://climable.org/chinatown-microgrid

Table: City of Boston Specific Recommendations regarding the ESMPs and Action by DPU

Issue Area	Recommendations	Rationale
Interconnection	1. Explore opportunities to expedite the interconnection process and provide greater transparency on expected timeframes for interconnecting DER and new electric loads. (*See e.g.,* National Grid's Active Resource Integration pilot, which is testing flexible solar and energy interconnections to accelerate distributed generation interconnections. National Grid ESMP pg. 75).	Currently, the interconnection process is lengthy and can be costly, thus deterring development of new renewable energy and electrification projects in new and existing buildings.
	2. Explore financing options for infrastructure needed for new electric loads and/or interconnections, *e.g.,* transformers. Consider issues such as who pays for and who owns the equipment, with potentially different approaches based on the type of building, *e.g.,* affordable housing versus research labs.	To the extent electrification is required or incentivized by state or municipal laws, it may make sense to distribute the costs to grow the grid over the entire rate base, rather than individual buildings (*see e.g.,* DPU Docket 20-75). This is particularly relevant for issues like transformers for smaller buildings, which enable users to buy electricity but do not create market opportunities for the building owner.
Data Access	1. The ESMPs should provide for the continued provision, and updating, of maps that illustrate hosting capacity for DEG and new electrification at both the substation and more localized levels, *e.g.,* at the feeder level and by address where feasible. 2. Provide public access to the EDCs' forecasting and modeling tools and data, both the underlying data and easy to read summaries presented in accessible formats (i.e., tables, charts) and in multiple languages.	Transparency around the capacity for new DEG and electrification projects and the need for new infrastructure is a critical tool for developing community understanding and support for new energy projects, and provides planning certainty to developers. Data availability will help create energy literacy and allow for meaningful stakeholder evaluation and engagement in siting processes and other decisions regarding the development of additional NWAs, DEGs and grid infrastructure.
Smart Systems	1. Include smart technology, such as meters and inverters, in new systems/infrastructure and assess integrating into	Smart systems are important components of many innovations and developing technologies, from projects like microgrids and virtual

Issue Area	Recommendations	Rationale
	existing systems. 2. Investigate and deploy grid-interactive efficient buildings (this concept is being explored at the Mary Ellen McCormack project in South Boston).	power plants to time varying rates. Smart systems can increase DER hosting capacity, including improving demand response programs, and improve grid reliability. ESMPs should evaluate integrating these technologies now and going forward so that we have the backbone needed for data-dependent programs.
Microgrids	1. Address how EDCs will activate microgrids and integrate islandable localized energy generation with other grid operations. 2. Address the relationship between third-party and EDC ownership and operation of various microgrid components. 3. Address the ability of private parties to run electric lines across public ways without utility consent. 4. ESMPs should look to deploy microgrids and virtual microgrids now, while we continue to explore ownership models, configurations, etc. Early pilot projects could include Boston's ready to implement Marine Park Microgrid pilot.	Municipalities and private parties are interested in using microgrids, but additional certainty around how EDCs and the DPU will interact with and regulate microgrids is needed to support continued investment. For example, (i) knowing how EDCs will activate microgrids will inform municipal requirements for developers to to build to microgrid-ready standards, and (ii) confirmation from DPU that EDC consent is not required to run electric lines across public ways could support more innovative multi-party microgrids.
Virtual Power Plants	1. The ESMPs should include more discussion of pilot projects for virtual power plants (VPPs), building off National Grid's proposals for VPPs that would aggregate behind the meter residential solar, connected batteries, and smart thermostats to deliver grid services based on targeted distribution network constraints (National Grid ESMP pg. 15). 2. DPU should open a docket to investigate potential rates, particularly distribution charges, for VPPs.	While the ESMPs identified an imminent need to increase the capacity and flexibility of the electric grid that will require the development of new substations, we should also explore alternative options like VPPs. VPPs may help limit the need for new infrastructure, including flattening peak demand and the need for additional transmission resources. While Massachusetts' existing demand response programs are important and should be continued, we need to explore virtual power plants as well.

Issue Area	Recommendations	Rationale
Solar for Low-Income Owners and Tenants	1. Pilot ownership programs for solar on small low-income housing that provides benefits to owners and tenants while avoiding out of pocket expenses and protecting the affected residents from bill increases. (*See e.g.,* Eversource ESMP pg. 285)	Low-income owners and tenants often have limited access to solar and/or the benefits from on-site solar, including financial barriers to direct ownership. EDC financing for rooftop solar owned by low-income owners/landlords that assures savings to the building owner and occupants may reduce overall costs to the general rate payers because of the differential in pricing for solar and electricity discounts for low-income consumers.
Integrate EVs into Demand Response	1. Pilot bi-directional charging for municipal or privately owned large electric vehicle fleets.	Electric vehicles present a potential opportunity for demand response. The City currently has an electric school bus pilot program with a goal of full electrification by 2030. Entering into a utility-municipal partnership, this municipal-owned electric fleet could serve as a reliable backup power source.
Resilience Nodes	1. ESMPs should provide for coordination with municipalities to develop resilience nodes in neighborhoods with known grid congestion. Pilot projects could explore combinations of smart systems, demand response programs, solar generation and storage systems, all with different models of financing and ownership.	Resilience nodes in high priority areas that intersect with high solar generation potential can protect residents and increase access to reliable, resilient and affordable energy. Municipal and community engagement is important to identify priority areas, *e.g.,* high levels of medical electricity dependency or lack of emergency cooling shelters, and to advance community justice.
Rate Structures	1. Run pilot and/or shadow programs to explore new rate structures, *e.g.,* a separate electric rate for low-income consumers with heat-pumps, time varying rates, or peak-load rates. DPU should authorize such pilot/shadow programs and open a docket to explore alternative rates in more detail. 2. Coordinate with gas companies to explore a shared rate for customers converting to electric heat that would support continued maintenance of the gas system without the costs being borne solely by a shrinking rate base.	The ESMPs propose large amounts of capital spending but do not present detailed information on rate impacts or ways to mitigate potential impacts. Rate impacts are an issue in other programs as well, such as the Mass Save program, where concern has been raised about short-term rate impacts on low-income customers that convert to electric-based heat and/or assume heating bills because of electrification in their buildings.

Issue Area	Recommendations	Rationale
Transmission Planning	1. Going forward, the EDCs and DPU should consider when costs associated with the ESMPs could be categorized as transmission costs.	Certain transmission system related costs may be eligible for different forms of cost recovery and thus borne by a larger group than a single ESMP's ratepayers.

Thank you for your attention to these comments. We appreciate your ongoing work on this important issue and look forward to future opportunities to engage in the grid modernization proceedings. Should you have any questions, please contact Aladdine Joroff, Director of Climate Policy (aladdine.joroff@boston.gov; 617-635-3407).

Sincerely,

Chief Mariama White-Hammond
Environment, Energy and Open Space, City of Boston

Via Electronic Submission

November 15, 2023

Grid Modernization Advisory Council
c/o Elizabeth Mahony, Commissioner
Department of Energy Resources
100 Cambridge Street
Boston, MA 02110

RE: Grid Modernization Advisory Council Draft Recommendations

Chair Mahoney and Members of the Grid Modernization Advisory Council:

On behalf of the Northeast Clean Energy Council ("NECEC"), thank you for the opportunity to provide comments on *Observations and Recommendations of the Grid Modernization Advisory Council: Regarding Electric-Sector Modernization Plans,* released November 3, 2023.

NECEC is both a trade group representing all of the clean energy segments, and a mission-driven organization working to advance the just, equitable, and rapid transition to a clean energy future and a diverse climate economy. NECEC is dedicated to growing the clean energy economy in Massachusetts and across the region. Our nearly 300 members include companies based in Massachusetts and those from elsewhere who do business here or hope to make future investments in the state.

With the Electric-Sector Modernization Plan ("ESMP") process, established by *An Act Driving Clean Energy and Offshore Wind* ("Climate Law") in 2022, Massachusetts has an opportunity to chart a decisive course towards a just and equitable clean energy future that relies on a distribution system that reflects our dynamic, modern energy system. Through our comments below, and through the efforts of the Grid Modernization Advisory Council ("GMAC"), the Electric Distribution Companies ("EDCs"), the Healey-Driscoll administration, the Department of Public Utilities ("DPU"), and the legislature, we are hopeful that the eventual approval and implementation of the

ESMPs will mark a significant step forward in achieving our clean energy aspirations – safely, affordably, and reliably.

NECEC commends the GMAC for running an intensive, inclusive and transparent process. The GMAC has conducted a thorough review of the draft ESMPs and has developed a strong set of draft recommendations. Additionally, NECEC thanks the EDCs for their draft plans and their engagement throughout the process. Moving forward, NECEC encourages continued engagement with a broad set of stakeholders and highlights the significance of ongoing development and improvement of plans and processes to realize the intent of the Climate Law.

Based on the draft ESMPs, the work of the GMAC to date, and the draft recommendations of the council, NECEC offers comments below focused on three areas: process and stakeholder engagement; the need for proactive long-term distribution system planning; and technology modernization.

Process and Stakeholder Engagement

The GMAC process and the review of the draft ESMPs to date has been robust, accessible, and substantive. However, this is a novel process and will require intentional and iterative improvements to ensure long-term success, and it is important that meaningful engagement continues after the ESMPs are filed with the DPU. Sustained engagement with stakeholders – including the public, the clean energy development community, and advocacy organizations – is essential, both throughout the DPU process and after the DPU acts on the proposed ESMPs.

NECEC agrees with the *Draft GMAC Report – 11/3/23*, which states in Section 4: "It is imperative that the DPU investigate and implement rules and procedures for future ESMP iterations to efficiently evolve the ESMP process to best meet its intended purpose under law and the Commonwealth's clean energy policies and objectives." NECEC also supports the suggestion from GMAC member Kathryn Wright that process recommendations be made in the report itself, including:

- The need for collaborative forecasting and model development;
- The need for time to better understand alternative financing and alternative projects;
- And the need for deeper public education and engagement based on the current grid state and forecasting results for each region.

In addition to including initial process recommendations in the report, NECEC encourages the GMAC to develop additional recommendations for continued GMAC process and stakeholder engagement at all levels between ESMP filings and in future ESMP cycles. Thoughtful, well-planned grid expansion and modernization is at the core of the just, equitable and rapid transition to a clean energy future. This process is too crucial to happen in isolation every five years. Instead, it is important to build out a comprehensive process that provides opportunities for external stakeholders and experts to meaningfully participate in both the implementation of approved ESMPs and the development of future ESMPs.

NECEC also supports the recommendations of the GMAC Equity Working Group provided in the *Memorandum of the Equity Working Group – 11/3/23* and encourages the full GMAC to adopt these recommendations on behalf of the entire body. We particularly emphasize the need for public-facing materials to be reviewed for plain-spoken language, visualizations, clarity, and completeness. Engagement with the public that is accessible and inclusive will be instrumental in ensuring the long-term success of the ESMP process.

Finally, NECEC supports recommendations 10, 11 and 12 related to the proposed Community Engagement Stakeholder Advisory Group ("CESAG"). We appreciate the proposal by the EDCs to form the CESAG but agree with the members of the GMAC that it is important to have this advisory group live within the structure of the GMAC, be led jointly by the EDCs and the GMAC, and develop definitions of equity, establish quantifiable metrics, and provide clear explanations of the stakeholder process. Just as continued, meaningful stakeholder engagement is needed for the ESMPs to lead to a successful outcome, it is equally important to ensure that these engagement efforts are well-coordinated and thoughtfully planned as part of a clear, consistent and unified strategy.

Proactive Long-term Distribution System Planning

To meet Massachusetts' decarbonization goals and the intent of the Climate Act, our distribution grid must be open to the speedy interconnection of distributed energy resources of all kinds, not the barrier that it is so often today. Reducing the timelines and current uncertainty of the process to interconnect will go a long way to increasing the reliability and resilience of our grid and is essential to facilitate the transition to a clean energy future. This will require an interconnection process and cost allocation methodology that is proactively planned, fast, low-cost, and predictable.

The Provisional System Planning Program established under D.P.U. 20-75 was a significant step forward for the interconnection process in Massachusetts. That said, the Provisional Program and the resulting capital investment project proposals were still fundamentally reactive in nature, and the DPU emphasized the need to transition to a proactive long-term distribution system planning process.

In the order approving the Marion-Fairhaven Capital Investment Project in docket D.P.U. 22-47, DPU wrote: "Recent legislation enacted on August 11, 2022, the 2022 Clean Energy Act, establishes a new framework requiring the Distribution Companies to submit five-year electric-sector modernization plans for review and input by a Grid Modernization Advisory Council and subsequent review by the Department. One objective of these plans is to proactively upgrade the distribution system to enable increased, timely adoption of renewable energy and DG, and shall include a description of "alternative approaches to financing proposed investment, including, but not limited to, cost allocation arrangements between developers and ratepayers."

The ESMPs, however, propose to continue with capital investment projects rather than moving to a holistic, unified, and truly proactive approach. While we recognize that there will need to be a transition period as the department considers the remaining capital investment project proposals, it is also critical that the ESMPs address how the EDCs propose to move to a proactive planning process and develop a long-term cost allocation methodology.

As such, NECEC strongly supports the proposed revisions to recommendation 3 provided by GMAC member designee Kate Tohme, which are included in the *Draft GMAC Report – Meeting Version* that was discussed in the GMAC meeting on November 9, 2023. In particular, we agree that:

- The proactive planning process should be as uniform across all three EDCs as possible, ensuring coordination of overarching assumptions and DER stakeholder engagement.
- The proposed long-term proactive distribution system planning process for the interconnection of distributed generation should include factors that drive development of distributed generation by enabling hosting capacity in locations that benefit the Commonwealth as a whole and further the state's clean energy objectives.
- Factors should include land use, siting near load, and coordination with infrastructure upgrades necessary to meet overarching clean energy goals.

- Proactive planning should account for existing group studies and queue, as well as creating hosting capacity to meet service territory and subregion pro rata shares of DER development needed to meet the Commonwealth's objectives.
- Planning should account for the lapse in time between enabling hosting capacity and achieving installed capacity.
- The ESMPs should propose a long-term cost allocation methodology for proactive infrastructure upgrades to enable the interconnection of distributed generation to succeed the reactive investment approval process conducted through the Provisional System Planning Program.
- The ESMPs should contemplate both a cost allocation methodology for medium and large DG and for small residential DG facilities.
    - If this is not possible before the January filing, then the EDCs should submit a detailed proposal and timeline for a stakeholder process that will develop a long-term cost allocation methodology.
    - This proposal should include how the stakeholder engagement and discussion will occur in parallel to the ESMP proceedings and should propose a date by which the EDCs will file a long-term cost allocation proposal at the DPU.
- The EDCs should submit a detailed proposal for streamlining of CIPs over the next 5 years, including incorporation of proactive system planning in advance of the next ESMP process.

NECEC welcomes the opportunity to engage with EDCs, the GMAC, industry members, and other stakeholders to develop a forward-looking and long-lasting interconnection and cost allocation methodology.

Technology Modernization

The draft ESMPs include some discussion of the potential for new technologies, such as Advanced Distribution Management Systems (“ADMS”), Volt VAR Optimization (“VVO”), Distributed Energy Resource Management Systems (“DERMS”), and Advanced Metering Infrastructure (“AMI”), which will unlock additional capacity, resilience, and ability to manage a modernized grid. While we understand that the EDCs are working with a group of interested stakeholders to schedule a meeting in December for a focused discussion on this topic, we also ask that the ESMPs filed with the DPU in January provide more specific details about the ways in which they intend to implement these new technologies, including the earliest possible timeline for implementation. In particular, we ask the EDCs to address the following questions:

- What are the specific intended uses of DERMS to enable DERs and electrification?
- In what ways could VVO with AMI technologies and other capabilities of advanced inverters be used to mitigate upgrades required to interconnect in the absence of DERMS?
- Will DERMS be used to enable DER to manage distribution-level voltage issues?
- To what extent is it possible to allow for the management and interaction between different technologies and use cases instead of designing for the worst case, or to design for some level of management using DERMS?
- Do the EDCs have plans, prior to the full-scale implementation of DERMS, to use DERs to shift energy from low load hours to high load hours, which can provide benefits to substation equipment on circuits with large levels of DG generation?
- To what degree can behind-the-meter energy storage help enable electrification by supporting the system's electricity needs during peak periods?

We recognize that these are complex issues and that it may not be possible at this moment to enumerate all potential future uses or configurations of emerging grid technologies. At the same time, we ask that the final ESMPs provide more specific details and timelines for implementation.

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On behalf of NECEC and our members, thank you for the opportunity to provide comments. We are happy to answer any questions you might have.

Sincerely,

/s/ Tim W. Snyder
Tim W. Snyder
VP, Public Policy & Government Affairs
Northeast Clean Energy Council
tsnyder@necec.org

OnSite RENEWABLES

November 15, 2023

Chair Elizabeth Mahony
Grid Modernization Advisory Council
100 Cambridge Street, #1020
Boston, MA 02114

Dear Chair Mahony and Members of the Grid Modernization Advisory Council,

OnSite Renewables ("OnSite") is writing to offer public comment to the Grid Modernization Advisory Council (GMAC) regarding critical interconnection issues and suggested recommendations to the Electric Sector Modernization Plans (ESMPs). OnSite is a Massachusetts based energy storage developer that currently has over 500 megawatts ("MW") AC of distributed energy resource projects (DERs) in the interconnection queues of the three Massachusetts Electric Distribution Companies (EDCs) – National Grid, Eversource, and Unitil. Specifically, OnSite develops energy storage DERs called battery energy storage systems ("BESS").

Background

OnSite's BESS are designed to be installed behind the electric meters of Massachusetts businesses and to serve the electric load/demand of these businesses when the state's electric distribution system is experiencing peak load that strains its ability to serve all customers. By serving the businesses' electric load/demand with the BESS rather than from the state's electric distribution system, OnSite's BESS can significantly reduce the strain on the state's system. Businesses that host systems receive lease payments for siting the BESS on their properties and Massachusetts electric ratepayers receive the benefit of a more stable electric distribution system that requires fewer costly rate-based upgrades. Massachusetts also receives the benefit of a more efficient and reliable electric distribution system, the ability to safely accept higher amounts of renewable energy generation, and a reduction in climate altering Greenhouse Gas Emissions (GHG).

The two state programs OnSite is developing BESS to operate in are aimed at increasing the number of MW of BESS in the state and meeting the state's 1000 MW hour energy storage goals by December 31, 2025, as detailed in An Act to Advance Clean Energy, Chapter 227 of the Acts of 2018.

- The ConnectedSolutions Program (CS), incentivizes placing batteries behind the electric meters of businesses to serve the electric load of those businesses during peak load events. Peak load events often occur on the local distribution system on the hottest afternoons in the summer when air conditioning loads can cause the distribution system to hit a load peak, or the coldest days of winter when electric heating can cause a distribution system load peak.
- The Clean Peak Standard incentivizes using batteries to store the energy produced in the middle of the day by solar energy projects when the load on the distribution system is low, and later discharge the batteries onto the distribution system in the afternoon as load is rising. Operating in this manner offsets the strain on the system and GHG emissions caused by trying to serve the increasing load from traditional gas turbine electric generation stations.

On pages 73 and 74 of National Grid's Electric Sector Modernization Plan under "Promoting Energy Storage; Create Opportunities", it says the utilities plan to scale the existing CS demand response program.

In 2021, OnSite received written confirmation from each of the EDCs related to the CS program:

- BESS sized larger than the onsite load would still qualify without a cap on how much larger.
- BESS would be compensated for all of the electricity provided during a peak event (both the electricity used onsite to offset load, and the excess electricity exported onto the distribution system).

After OnSite filed all of its interconnection applications and applied to enroll in CS, National Grid denied, in bulk, all of OnSite's CS applications. The utilities then revised the ratepayer funded CS rules without any public stakeholder input, capped the CS incentive payments at 150% of onsite load (despite no previous cap), and established a grandfathered deadline of June 8, 2023 – the same day the new rules were published. OnSite had, and still has, no ISAs for its projects.

By significantly scaling back the CS program, National Grid's actions directly contradict its statements in its ESMP that it plans to expand the CS program. This calls into question National Grid's and the other utilities' commitment to supporting energy storage development in the Commonwealth.

<u>Interconnection Concerns</u>

OnSite is deeply concerned about the readiness of the Massachusetts grid and the current policies and approach of the EDCs towards clean energy interconnection. Without significant changes, clean energy interconnection will remain in limbo for many years to come. There are several critical roadblocks that hinder the integration of energy storage projects in Massachusetts. Interconnection is the most significant.

We urge the GMAC to address the following roadblocks in its report to the EDCs regarding the ESMPs. Without changes to the current interconnection process, Massachusetts will not meet its climate goals.

Over the past four years, the cost of interconnection upgrades borne by DER developers have risen rapidly and the industry is reaching a point where developing a BESS is financially feasible, but the cost of interconnecting the BESS to the utility's distribution system is *not* financially feasible. Over the past 4 years, interconnection costs have risen by as much as 800% and the timeline to complete the utility's studies has increased from 3 months to *at least* 18 months **(Figure 1).**

It is OnSite's view that interconnection cost increases are due to *how* the projects are studied by the utility, rather than the actual potential impacts the projects could cause to the grid.

National Grid is studying BESS using a study methodology that assumes the systems will charge from 11pm to 3pm in Summer and Winter, 11pm – 4pm in Fall, and 11pm – 5pm in Spring. These charge schedules ensure that the charging windows overlap with the peak hour of the peak day in each season other than winter. Studying a BESS assuming it is charging at its full capacity during the peak hour of the peak day in the summer creates a very high likelihood of the BESS causing thermal overloads of the grid's infrastructure, which results in the BESS being responsible for the cost of replacing miles of distribution feeders, one or more substation transformers, and in certain cases, entire substations. These are the most significant and expensive upgrades possible and it is OnSite's view that the vast majority of these upgrades would not be required if these BESS were studied using a charge and discharge schedule that matches how they intend to operate. **(Figure 2 graphs)**

The goal of the CS program is to discharge these BESS during peak events to reduce the load on the system. If OnSite's BESS are **not** discharging during those peaks, they aren't providing the environmental benefits the CS and Clean Peak programs were created to provide and are missing out on the program's revenue streams, which represent the majority of the revenue that makes the BESS financially feasible.

We urge National Grid to reconsider its study methodology to be more in line with how a rational market participant would operate its batteries.

Additionally, the Figure 2 graphs show that the utilities' mandated schedule assumes the BESS will discharge in the afternoon and evening when the load is already dropping, which would result in the load curve getting steeper. That would cause additional strain on the distribution system. Energy storage is supposed to be used to level the load curve, not increase the curve's climbs and drops, which is what the utilities schedules are causing.

The way the BESS are modeled assumes they will be operated in a manner that provides limited benefit to the grid, misses out on material revenue streams, and maximizes potential upgrade costs.

OnSite filed interconnection applications for over 100 5MW BESS with an assumption of $750,000 of interconnection costs for each project. Preliminary impact studies received to date have had an average interconnection cost of approximately $5 million per project. In one example, OnSite's 5 MW project in Seekonk is sharing the cost of replacing an entire substation with a 1.5 MW PV & battery project. OnSite's estimated share of the $15MM substation replacement cost is $11.5MM.

Another example was delivered to OnSite on Monday, November 13 in the form of a first final System Impact Study (SIS) for one of its projects, which includes estimated interconnection costs (+/- 25% cost estimate). In the SIS a required upgrade related to the project is upgrading 1,500 feet of a 13.2 kV distribution feeder to newer bigger wires. This is a relatively common upgrade and the 1,500' distance is shorter than what many BESS or solar projects typically require. As recently as 2020 & 2021, the utility per mile cost of upgrading a 13.2 kV distribution feeder was $250,000 - $500,000 per mile. In the case of OnSite's project, the 1,500' has an estimated cost of $573,769.76, which is over $2 million per mile, or 4 to 8 times more expensive than it was just a few years ago. National Grid and the other utilities provide no written or verbal record of how that cost is determined. Developers are expected to agree with the cost or cancel their project.

Recommendations to the GMAC to inform the EDCs ESMPs:

- Require that no customer be denied the right to interconnect an energy storage facility.
- Specify time limits for both the initial interconnection application process and for the utility's interconnection design and construction process.
- Require utilities to allow developers to self-construct interconnection upgrades.
- Establish a permanent office of an ombudsperson with the power to recommend civil penalties against the utilities when appropriate.
- Require the utilities to share their pricing estimates and the underlying assumptions when creating cost estimates in System Impact Studies and Group Studies.
- Connected Solutions:

- Relocate administration of CS from the EDCs to a state entity.
- Grandfather CS applications received before the *significant* program changes announced June 2023.
- Look to Connecticut for its grandfathering model.

OnSite also supports the recommendations made by Kate Tohme of New Leaf Energy:

1. *The ESMPs should propose a long-term proactive distribution system planning process for the interconnection of DG, utilizing the analysis process proposals and subsequent comments submitted in DPU 20-75. Proactive distribution system investments are critical to ensuring DERs can interconnect to the grid at a reasonable cost and expeditious manner to meet the Commonwealth's goals. The proactive planning process should be as uniform across all three EDCs as possible, ensuring coordination of overarching assumptions and DER stakeholder engagement.*
2. *The ESMPs should propose a long-term cost allocation methodology for proactive infrastructure upgrades to enable the interconnection of DG to succeed the reactive investment approval process conducted through the Provisional System Planning Program. If this is not possible before the January filing, then the EDCs should submit a detailed proposal and timeline for a stakeholder process that will develop a long-term cost allocation methodology. This proposal should include how the stakeholder engagement and discussion will occur in parallel to the ESMP proceedings and should propose a date by which the EDCs will file a long-term cost allocation proposal at the DPU.*
3. *Extension of the Provisional System Planning Program as currently proposed in the ESMPs will require significant additional adjudicatory proceedings over the next 5 years and will not incorporate proactive system planning as required by the Climate Act. The EDCs should submit a detailed proposal for streamlining of CIPs over the next 5 years, including incorporation of proactive system planning in advance of the next ESMP process. The proposal should include, at a minimum, batch review of existing group studies as well as application of the long-term proactive analysis process and cost allocation methodology in the interim between this and the next ESMP process.*

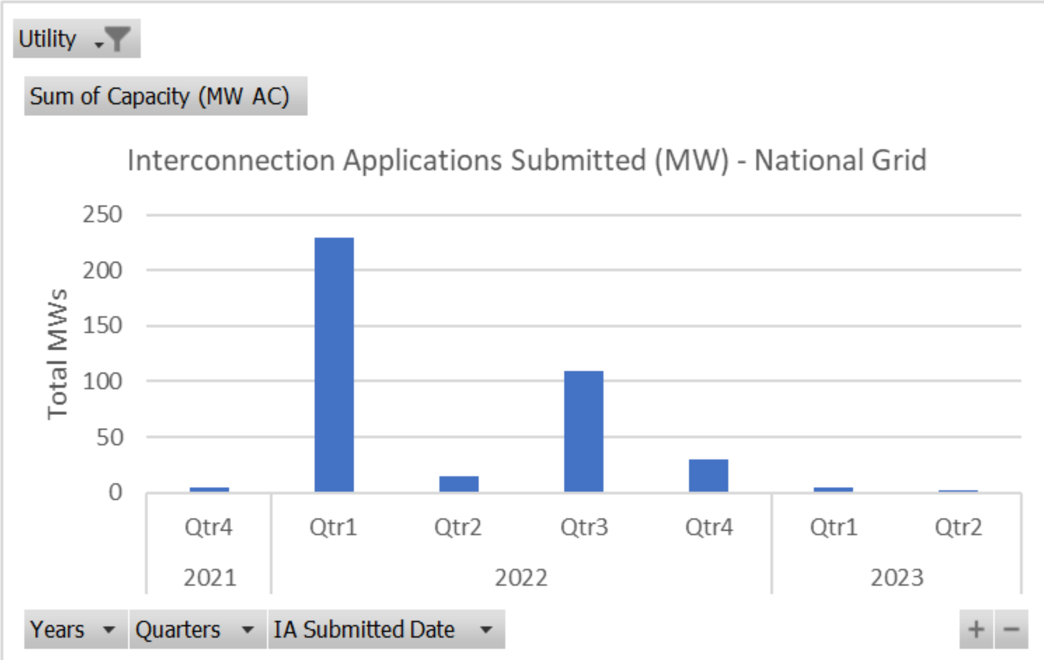
In our review of stated storage targets, it will be impossible for the EDCs and the Commonwealth to reach energy storage goals unless urgent measures are taken to improve the realities we are trying to work through on a daily basis.

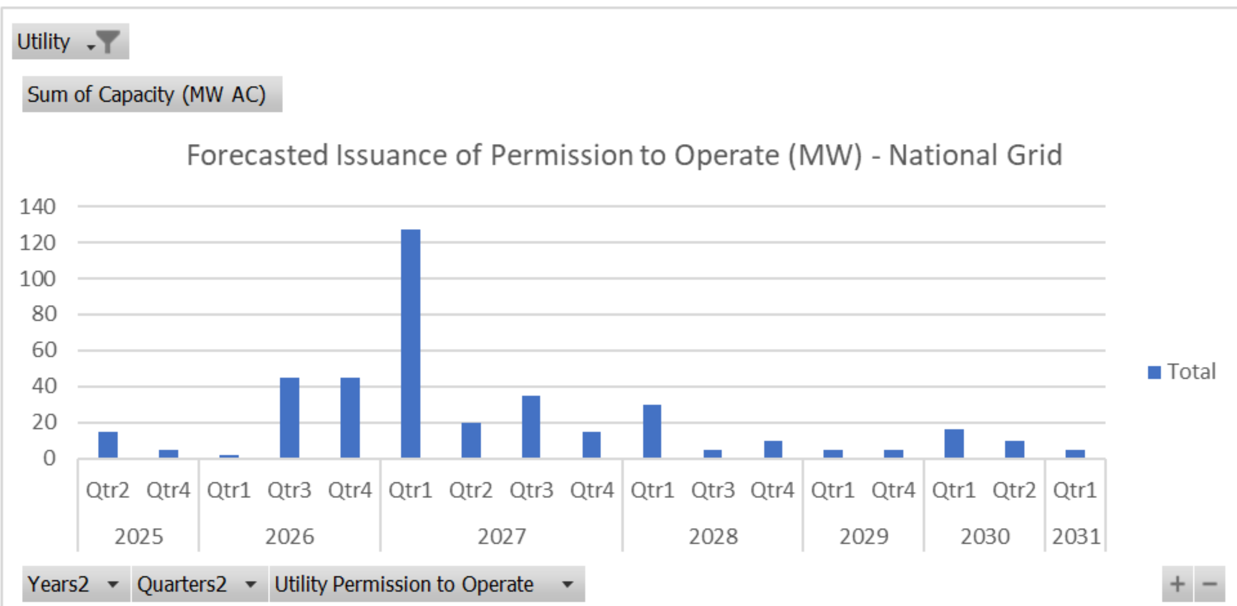
We thank the Grid Modernization Advisory Council for its critical work, and urge you to prioritize interconnection issues in your report to the EDCs regarding their ESMPs.

Sincerely,

Silas Bauer
OnSite Renewables

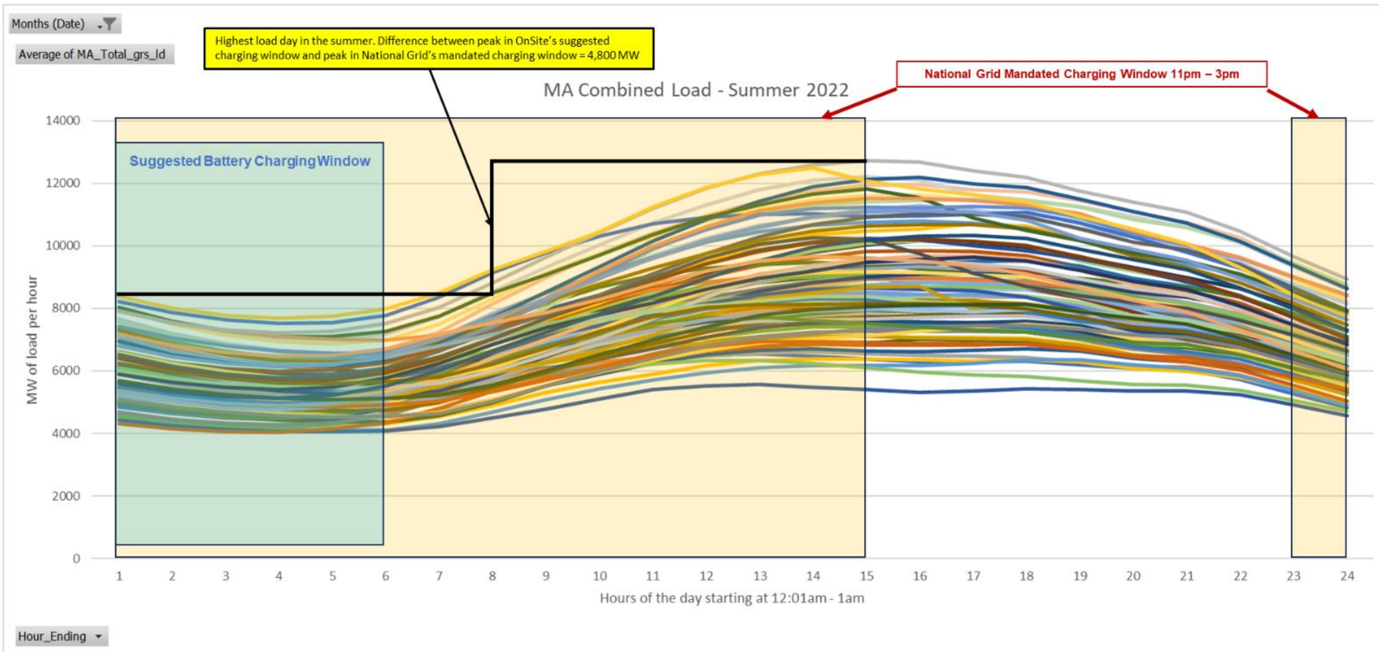
Figure 1: Interconnection Study Timelines

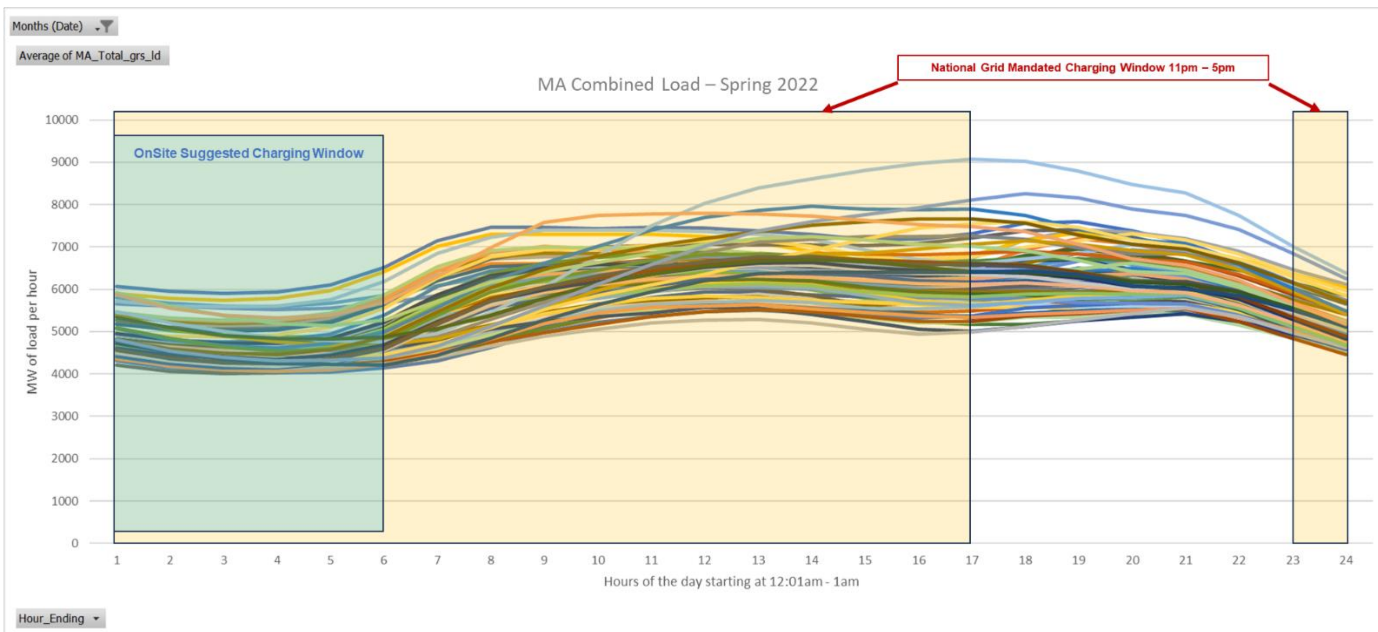


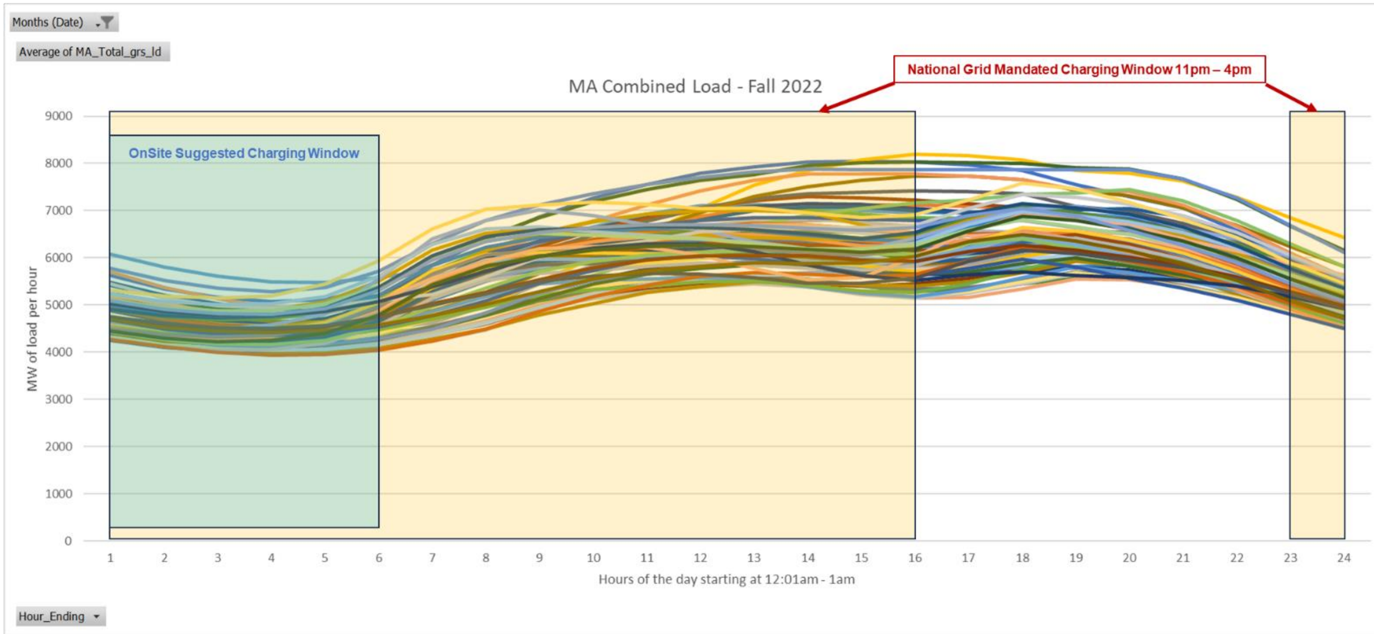


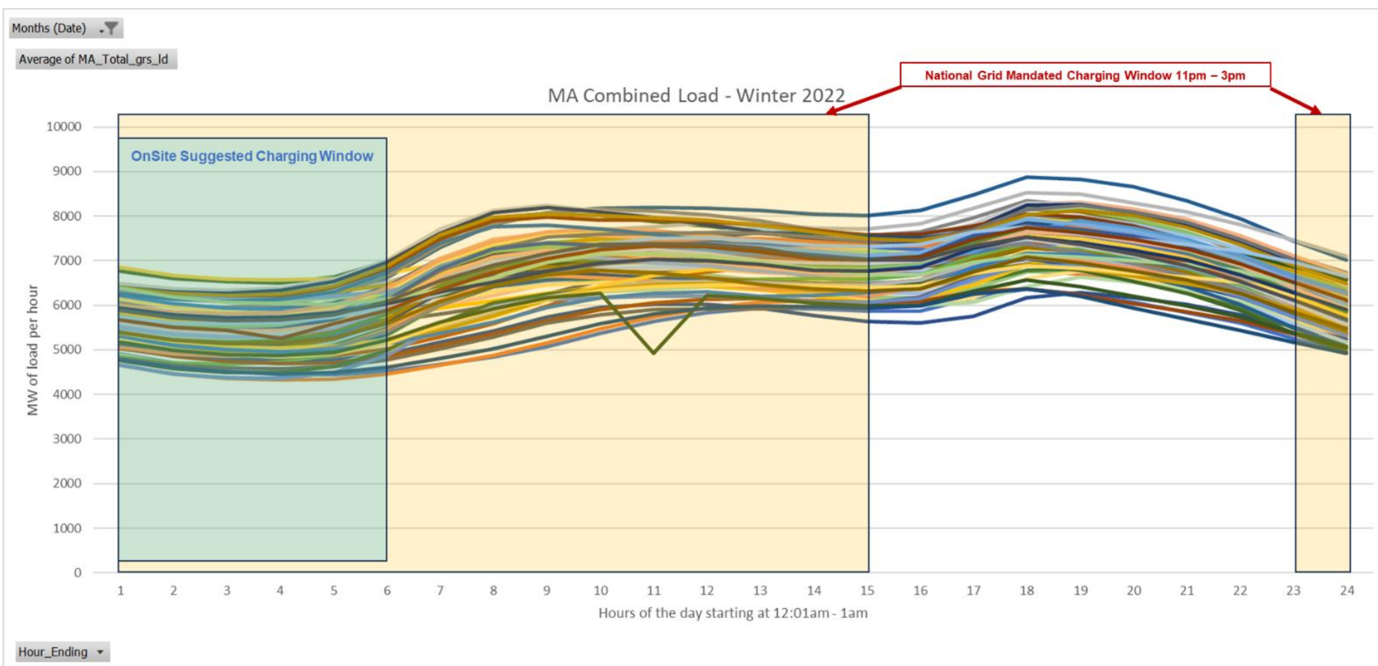
Longer study timelines lead to very long waits before projects can start operating. OnSite is estimating that the majority of its projects will reach Permission to Operate (PTO – permission to discharge and charge on the distribution system) from National Grid by 2026 into 2027. OnSite estimates that none of its projects will receive PTO prior to Q2 of 2025. Most projects will require 4-5 years to complete National Grid's studies and construction timeframes – time from filing an interconnection application to PTO (historically this timeframe was 1-2 years). ***National Grid stated in its Sept. 2023 ESMP that it alone will exceed the State's 2025 energy storage target based on the projects in its interconnection queue at the end of 2022. Data shows that OnSite projects made up approximately 75% of National Grid's interconnection queue at the time.***

Figure 2: Interconnection Study Charge/Discharge Schedules









National Grid's mandated charging schedule increases GHG emissions, increases the cost of interconnection, burdens ratepayers and developers with unnecessary costs, and kills projects, harming the state's ability to achieve its aggressive GHG reduction and energy storage goals.

ISO-NE 2023 ISO-NE Variable Energy Resource (VER) Data Series (2000-2022) Rev. 0 from: https://www.iso-ne.com/system-planning/planning-models-and-data/variable-energy-resource-data/

November 9th, 2023

Massachusetts Grid Modernization Advisory Council
100 Cambridge Street, 9th Floor
Boston, MA 02114

RE: Official Regulatory Comments on Grid Modernization Advisory Council (GMAC) and Electric-Sector Modernization Plans (ESMPs)

Piclo is pleased to submit our comments regarding the ongoing regulatory proceeding under G.L. c. 164, §§ 92B-92C, related to the GMAC and ESMPs.

Piclo has been at the forefront of innovation in the energy industry since it began in 2013. At Piclo, our mission is to decarbonize the grid and create a more sustainable energy future for all. We achieve this mission through the development of cutting-edge software solutions that enhance the intelligence, flexibility, and sustainability of energy networks.

Our flagship product, Piclo Flex, is the leading independent marketplace for energy flexibility services. Piclo Flex plays a pivotal role in enabling utilities and system operators to source energy flexibility from Distributed Energy Resources (DERs) aggregators during times of high demand or low supply. We have over 60,000 registered flexible assets and $73 million worth of flexibility contracts awarded. This translates to an impressive 16 GW of flex capacity registered and 2.4 GW of flexible capacity procured.

Piclo is proud to provide our services in six global markets, including the United States, United Kingdom, Ireland, Italy, Portugal, and Lithuania. Our collaboration with distribution and transmission system operators reflects our commitment to driving a global transition to Net Zero.

We understand the challenges that come with flexibility procurement and aim to reduce friction at every turn. We facilitate competitive auctions, ensuring that Flexible Service Providers (FSPs), like wind generation, solar PVs, electric vehicles, and batteries, have the opportunity to bid for contracts, thereby securing the best possible price. This approach not only encourages participation but also fosters standardization and scalability, leveling the playing field and streamlining the path to a Net Zero future.

With our experience working with DERs, grid modernization processes, and energy flexibility around the world, Piclo would like to submit the following comments for consideration:

Regarding non-wire alternatives and battery storage:
When developing the grid of the future, Piclo believes that harnessing the flexibility of DER is essential. With the flexible energy that DER can unlock, we can increase the capacity of our grid, limit the costs/delays associated with additional network reinforcement, and foster clean energy solutions that increase grid reliability and decrease costs. To achieve this, ESMPs should seek to more meaningfully reincorporate all DER assets, including batteries and assets owned by third parties. This also requires that bridge-to-wire alternatives (a.k.a non-wire-alternatives) are more robustly integrated into future grid planning through the ESMPs.

Piclo would offer its report on the Value of Centralized and Decentralized Storage as a resource as the GMAC looks to incorporate the value of batteries and bridge-to-wire solutions (NWA).

Regarding the value of DER:
Some ESMPs seem to indicate that DER adoption/installations have little impact on the reduction of winter or summer peak load. Piclo has found that DER has multiple beneficial value scenarios that can alleviate load during peak demand and provide significant value to the grid. We would suggest further analysis when it comes to attributing value to DER during periods of peak seasonal demand. As flexible energy and DERs have been integrated into the United Kingdom's network, there are lessons to be learned. Piclo would offer its report on The Value of Flexibility as one source of some of these learnings.

Furthermore, in order to have a credible Benefit Cost Analysis, the value of DER must be properly identified. Unlike energy efficiency, the flexible energy provided by DERs has a one-to-one correlation with energy generation, providing an opportunity for emergency power from clean, carbon-free sources. Thus the value of DER should include considering the value of the energy provided by DERs (which should relate to the real-time costs of meeting peak/emergency demands), the value of meeting clean energy goals, and the environmental merits of utilizing clean DER resources.

Regarding Regulatory Incentives:
There is mention of a Grid Service Compensation Fund in the ESMPs. The proposal to establish a fund to compensate dispatchable DER and flexible loads addresses the important issue of adequately remunerating DER assets. To ensure the development of a reliable, clean, and flexible grid there should be consideration of regulatory mechanisms that incentivize the development of a clean, DER-driven grid. This may include a compensation fund leveraged by utilities, changes in rate structures to settle up dispatched DER assets, or incentives for utilities to resolve grid challenges leveraging grid modernization technologies.

Regarding a Flexibility Marketplace:
A flexible energy marketplace driven by the system operators can provide an immediate, market-driven, DER solution to a variety of grid challenges including but not limited to relieving grid congestion, meeting peak demand, providing emergency response solutions, and filling the gaps of variable energy production. As a leading flexible energy marketplace, Piclo commends National Grid for proposing the use of a flexibility marketplace to procure a market-driven DER solution to grid challenges. As more DER connects to the grid and we continue the process of electrifying industries, a DER flexibility market can provide immediate, cost-effective, and equitable solutions that address the challenges of an evolving energy landscape.

Piclo's report, A new era for DER participation in energy markets? A look at the US FERC Order No. 2222, discusses the challenges and opportunities ahead as we move towards a more modern DER-centered grid. As National Grid proposes this flexibility marketplace, Piclo would implore the GMAC and the Massachusetts Department of Energy Resources to invest in the pilot, carefully study the benefits of such a program, and consider how the pilot can be expanded if the results prove beneficial to the the grid, system operators, and electricity customers.

Regarding Further Study of the value of DER:
Properly valuing DERs is essential to building the grid of the future that can harness flexible energy, provide adequate incentives for clean energy solutions, and offer clean energy at an affordable price point. Piclo is aware of the *Value of DER for Distribution System Grid Services* study being conducted

by Baringa and commends the Massachusetts Clean Energy Center on prioritizing this initiative. We believe that the GMAC, DOER, and others should look to this report for guidance in creating the regulatory mechanisms to harness the full potential of DER. The topic of valuing DER is a complex and multifaceted issue, one that warrants ongoing study. As such Piclo believes that there should be a process for considering the results of the Baringa study and addressing additional research gaps that can serve the GMAC in future proceedings.

We suggest that the GMAC and DOER determine how to continue this research. Such a study should consider the comprehensive value of DER, addressing challenges such as grid congestion, backup power during peak demand/emergency response, dynamic locational pricing, carbon emission reductions, increased system reliability, and additional value stacking.

Thank you for considering our comments. Piclo appreciates the opportunity to contribute to the GMAC process and the development of a forward-thinking and sustainable energy grid. Please feel free to contact us for further discussion.

Regards,
John Greene

Piclo
Policy and Regulatory Affairs Manager
Cell: 603-620-0654
John.Greene@piclo.energy

Fermata Energy

Via Electronic Submission

December 12, 2023

Grid Modernization Advisory Council
c/o Elizabeth Mahony, Commissioner
Massachusetts Department of Energy Resources
100 Cambridge Street Boston, MA 02110

Dear Chair Mahony and Members of the Grid Modernization Advisory Council,

Fermata Energy appreciates the opportunity to provide comments to the Grid Modernization Advisory Council (the "Council") on the electric distribution companies' ("EDCs'") draft Electric Sector Modernization Plans ("ESMPs") dated September 2023.

Founded in 2010, Fermata Energy is a leading vehicle-to-everything ("V2X") bidirectional charging services provider. Fermata Energy designs, supplies, and operates the technologies required to integrate electric vehicles ("EVs") into homes, buildings, and the electric grid. Fermata Energy's V2X platform incorporates CHAdeMO and Combined Charging System ("CCS") connectors in a bidirectional charger and management software with the EV and electricity user. Fermata Energy's V2X platform unlocks the value of an EV and allows the vehicle to act as a dispatchable energy storage resource when the vehicle is not in use. The company's customers today are earning thousands of dollars through vehicle-to-grid ("V2G") and vehicle-to-building ("V2B") programs nationwide. The company's bidirectional EV charging system is the first in the world to be certified to a new North American safety Standard, UL 9741, the Standard for Bidirectional Electric Vehicle Charging System Equipment and the first to earn approval in the U.S. from a major original equipment manufacturer ("OEM") for battery warranty.

On behalf of Fermata Energy, I appreciate the Council's consideration of our observations and recommendations to advance bidirectional charging and V2X technology as a central part of the Massachusetts EDC's grid modernization plans. Bidirectional charging with V2X technology provides a new grid-scale flexibility resource that is vast, ubiquitous throughout the distribution system, and can be deployed quickly at scale.

Transportation Sector Decarbonization

The Massachusetts Clean Energy and Climate Plan for 2050 states that the path to economy-wide decarbonization relies on an expanded role for the power system.[1] This is particularly relevant for transportation decarbonization. The state's Clean Energy and Climate Plan calls for 97 percent of the

[1] See Executive Office of Energy and Environmental Affairs, Clean Energy and Climate Plan for 2050, available at https://www.mass.gov/doc/2050-clean-energy-and-climate-plan/download.

light-duty vehicles (5 million) to be electrified and 93 percent of medium- and heavy-duty ("MHD") vehicles (over 350,000) by 2050.[2]

A study conducted for the Electric Vehicle Infrastructure Coordinating Council forecasts a potential growth of up to 1,400 MW in peak demand from EV charging in Massachusetts by 2030. With effective managed charging programs, the actual average load from EV charging was modeled to be between 630 and 700 MW.[3] This study highlights the importance of vehicle grid integration solutions to manage EV charging to minimize the impact on peak demand. The study, however, fails to consider bidirectional charging with V2G technology. These same EVs with bidirectional charging can send power back to the grid during net peak hours, thereby reducing the need to run costly and polluting peaker plants.

The Benefits of V2G

According to the Smart Electric Power Alliance, a non-profit organization focused on smart grid topics, the 2.1 million EVs currently in use in the U.S. have approximately 126 gigawatt-hours of battery storage or five times more than the current grid-connected battery storage.[4] Bloomberg New Energy Finance ("BNEF") projects that 90 percent of all lithium-ion batteries manufactured through 2045 will be in EVs.[5] The stationary storage segment will remain a small fraction with EVs having a much larger energy storage capability.

Massachusetts's EDCs have an historic opportunity to integrate bidirectional charging as a core component to their draft ESPMs and further solidify the state as a leader in advancing emerging clean technology. The benefits to Massachusetts residents would be significant and include the following:

Support Achievement of Climate Goals

Just like stationary storage, V2X bidirectional charging platforms can reduce carbon and criteria pollutant emissions from generators by shifting electricity consumption to the cleanest hours of the day and removing the need for dirty thermal peaker plants to generate electricity. Batteries can absorb excess renewable generation, reducing the curtailment of wind and solar and then releasing that energy back to homes and businesses when needed. V2X, however, is more cost-effective than stationary storage, as ratepayers don't have to pay for the purchase of the EV battery. V2X can also accelerate the transition to renewable energy and can also be deployed quickly and at scale relative to stationary storage.

Provide Valuable Grid Services

Massachuesetts has already demonstrated the value of bidirectional charging and V2X with several projects participating in the EDCs' GridConnection solutions programs, which are part of their 3-year

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[2] Ibid.

[3] See Electric Vehicle Infrastructure Coordinating Council Initial Assessment to the General Court August 11, 2023 available at https://www.mass.gov/doc/evicc-final-assessment/download#:~:text=Overall%2C%20Synapse's%20numbers%20indicate%20a,between%20630%20and%20700%20MW.

[4] See Smart Electric Power Alliance, The State of Bidirectional Charging in 2023 available at https://sepapower.org/resource/the-state-of-bidirectional-charging-in-2023/.

[5] See Bloomberg Law, Electric Vehicles to Drive Massive Battery Demand: BNEF Chart available at https://news.bloomberglaw.com/environment-and-energy/electric-vehicles-to-drive-massive-battery-demand-bnef-chart.

energy efficiency plans. With V2X bidirectional charging at scale, utilities gain a large new flexibility resource that can provide the same grid services that stationary energy storage projects provide today. V2X can play an important role in addressing the intermittent production of solar and wind power generation. Furthermore, V2X is an excellent strategy to support Massachusetts' Clean Peak Standard by charging EVs during peak hours of renewable generation and sending back to the grid this clean energy during peak load hours.

EVs in Massachusetts have already proven to be valuable resources participating in the EDCs' ConnectedSolutions demand response programs. Highland Electric Fleet's Beverly Public School fleet electrification project demonstrates the viability of electric school buses as bidirectional V2G resources, receiving revenue via National Grid's ConnectedSolutions program[6] and providing a template to scale the service at additional deployment sites. BlueHub Capital and Fermata Energy, the country's premier V2G services provider, recently launched the first V2G pilot program in the nation for a multi-family affordable housing building in Dorchester, MA. The pilot is designed to increase affordable access to EVs for low-income drivers through an innovative V2G car share program that is partially financed by earning Eversource ConnectedSolutions revenue.[7] Fermata Energy also worked with FirstLight Power and Skyview Ventures to deploy the first ever V2G bidirectional charging stations in Western Massachusetts.[8]

Help MA Achieve its Transportation Decarbonization Goals

EV owners can get paid by selling electricity back to the grid, significantly cutting the cost of vehicle ownership. Offsetting the cost of owning and maintaining an EV through the revenue earned from bidirectional charging can accelerate EV adoption. The BlueHub Capital and Fermata Energy pilot referenced above uses the revenue from Eversource's ConnectedSolutions program to reduce the monthly EV lease payment for a low-income household. Bidirectional charging and V2G can provide equitable EV access to low-income households using this innovative approach, a segment that has not seen significant EV adoption given the cost barrier.

Increase Community and Household Resiliency

Incorporating V2X bidirectional charging cost-effectively supports grid resilience. During blackouts, EV owners with bidirectional chargers can power their homes, businesses, and critical infrastructure. The energy in an EV can power a typical home for three or more days. Using EVs as a source of backup power for homes or within a larger microgrid also avoids emissions from gasoline- or diesel-based generators.

[6] See CISION PR Newswire, Highland Electric Fleets Coordinates Electric School Buses' Summer Job - Supporting Local Grid with Vehicle-to-Grid Technology available at https://www.prnewswire.com/news-releases/highland-electric-fleets-coordinates-electric-school-buses-summer-job--supporting-local-grid-with-vehicle-to-grid-technology-301611928.html.

[7] See Enterprise Mobility, First-in-Nation Pilot to Provide Low-Income Driver with Affordable Access to EV Launched in Boston by BlueHub Energy, Fermata Energy, Enterprise Holdings & Codman Square Neighborhood Development Corp. available at https://www.enterprisemobility.com/news-stories/news-stories-archive/2023/09/pilot-for-affordable-access-to-evs-launched-in-boston.html.

[8] See businesswire, FirstLight Power, Fermata Energy, and Skyview Ventures Partner to Launch First Ever Vehicle-to-Grid Charging Platform in Western Massachusetts available at https://www.businesswire.com/news/home/20220908005343/en/.

Save Massachusetts' Ratepayers Money

EV adoption has already been shown to significantly benefit utility ratepayers as more revenue is generated from the sale of electricity for EV charging.[9] Several studies have demonstrated that bidirectional charging and V2G offers significant benefits beyond smart charging or V1G.[10] A 2018 Electric Power Research Institute study projects $1 billion in annual ratepayer benefits in California if 50 percent of chargers were bidirectional with V2G technology.[11] While no similar study has been done yet for Massachusetts, the potential for significant ratepayer benefits from bidirectional charging exists and should be explored.

EDC's Electric Sector Modernization Plans and V2G

Of the three EDCs' Electric Sector Modernization Plans (ESMPs), National Grid provides the most coverage of V2G. The topic is completely absent from Unitil's ESMP and Eversource's ESMP only referenced V2G briefly in Section 9.1.2. (Transport: Electric Vehicle Charging Demand Management Scenarios).[12]

Fermata Energy commends National Grid for providing several references to V2G in its ESMP. In Section 4.1 (State of the Distribution System and Challenges to Address), National Grid's ESMP references V2G as a strategy to support fleet electrification.[13] Section 9 (2035 - 2050 solution set – Building a decarbonized future) National Grid references the role that V2G can play allowing EVs to serve as flexibility resources.[14] National Grid's ESMP describes the opportunity as their system transitions to being winter peaking to use battery storage, including V2G, to help manage winter heating loads.[15] Finally, Section 9.1.2 (Transport: Electric Vehicle Charging Demand Management Scenarios) of the ESMP discusses three common vehicle grid integration strategies including V2G, vehicle-to-home (V2H), and vehicle-to-load (V2L).[16]

In summary, National Grid's ESMP states: "**Vehicle-to-Everything (V2X) EVs of all types may be able to contribute to alleviating the peak if bidirectional charging capabilities continue to develop and**

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[9] See Synapse Energy Economics, Electric Vehicles Are Driving Electric Rates Down available at https://www.nrdc.org/sites/default/files/media-uploads/evs_are_driving_rates_down_dec_2022_update_0.pdf.

[10] For example, Tarroja and Hittenger (2021) estimate that the value of smart charging only reaches $87 per vehicle-year while that for vehicle-to-grid can reach $2,850 per vehicle-year in California, see Energy, The value of consumer acceptance of controlled electric vehicle charging in a decarbonizing grid: The case of California available at https://www.sciencedirect.com/science/article/pii/S0360544221009397.

[11] See The Electric Power Research Institute, Vehicle-to-Grid: $1 Billion in Annual Grid Benefits? Available at https://eprijournal.com/vehicle-to-grid-1-billion-in-annual-grid-benefits/#:~:text=V2G%20technology%20can%20provide%20%241,peak%20shaving%20and%20ramping%20support.

[12] See Eversource, Electric Sector Modernization Plan available at https://www.mass.gov/media/2640011/download?_gl=1%2Ako8zfs%2A_ga%2ANzUwNDI5MDE3LjE2NTA5ODEyMjQ.%2A_ga_SW2TVH2WBY%2AMTY5MzkyMDE2OS4zNi4xLjE2OTM5MjM1NzQuMC4wLjA.

[13] See National Grid, Future Grid Plan: Empowering Massachusetts by Building a Smarter, Stronger, Cleaner and More Equitable Energy Future available at https://www.nationalgridus.com/media/pdfs/our-company/massachusetts-grid-modernization/future-grid-full-plan-sept2023.pdf, page 71.

[14] Ibid., page 340.

[15] Ibid., See Section 9.1.1 Buildings: Winter Demand Response Scenarios, page 342.

[16] Ibid, page 344.

appropriate contractual arrangements can be made with customers. This is a nascent industry, however, and the exact nature and magnitude of this potential remains unknown."[17] Fermata Energy welcomes the opportunity to continue our collaboration with National Grid to evaluate the potential of V2G to provide the various grid services referenced throughout their ESMP.

The ESMPs of both Eversource and Unitil fail to acknowledge the significant potential of bidirectional charging and V2X technology as a key transformative grid modernization strategy. Eversource and Unitil should be required to include bidirectional charging with V2X technology in the "5- and 10-Year Planning Solutions: Building for the Future" section of their ESMPs. This is exactly the timeframe when EVs will begin to represent a significant portion of new vehicle sales and thus require significant investment in charging infrastructure.

Bidirectional charging with V2X technology represents the lowest cost form of grid storage and can be deployed at scale rapidly. Given this vast potential, Fermata Energy recommends that all the EDCs provide a detailed roadmap for bidirectional charging in their final grid modernization proposals that will soon be brought before the Massachusetts Department of Public Utilities.

Conclusions

Bidirectional charging should be central to the build out of EV charging infrastructure in Massachusetts given its potential to provide a vast flexibility resource for the grid. The technology has already been demonstrated to provide value to the Massachusetts grid through participation in the EDCs' ConnectedSolutions programs. Significant resources will be invested in EV charging infrastructure in Massachusetts in the next decade. Now is the time to ensure that this investment moves beyond the one-way charging and that Massachusetts' regulators embrace the huge potential that bidirectional charging can bring to Massachusetts' ratepayers.

Fermata Energy appreciates the opportunity to share comments with the Council on the EDCs' ESMPs. Please contact me directly if you have any questions or need additional information on bidirectional charging and V2X technology.

Sincerely,

/s/ Steve Letendre, PhD
Senior Director of Regulatory Affairs
Fermata Energy
steve@fermatenergy.com
802-779-3580

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[17] Ibid, page 344.

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ESMP comment letter

HEET is a Massachusetts nonprofit climate solutions incubator with a mission to reduce emissions now through systems change. We understand that the Grid Modernization Advisory Council ("GMAC") has taken on the task of reviewing and providing feedback on the Electric Sector Modernization Plans ("ESMPs") submitted in September. In reviewing the GMAC's observations about where additional information is needed for effectively understanding the current electric grid, and the need for intentional collaborative planning by the electric and gas sectors in leading the gas-electric transition, we believe that networked geothermal lies squarely in that space.

The GMAC specifically noted in Recommendation 7 that "the EDCs should include more discussion of investment alternatives and alternative approaches to financing investments, and clearly communicate these alternatives to stakeholders." and in Recommendation 9 that the EDCs should identify "policies that direct or incentivize the location of or criteria for electrification adoption or DER siting, and in so doing provide more certainty in locations needing significant investment or where alternatives may be particularly effective."

The GMAC has rightfully pointed out the need for greater innovation in broader planning and thinking (e.g., alternative rate design) as well as the need for concrete, targeted investments in the near term. As the GMAC is aware, and the as the Department of Public Utilities (the "Department") recently noted in its recent order that "it views networked geothermal projects as those with the most potential to reduce GHG emissions" D.P.U. 20-80-B, at 2.

Networked geothermal is not simply part of the necessary infrastructure of electrification, it is a solution that acknowledges the complex nature of thermal load. There are solutions from the gas side that can assist in this transition more directly as further detailed below. The Department has acknowledged its use as a key tool in this process, and as the innovator of the gas to geothermal network electrification pathway, we offer these comments to the GMAC to deepen its learning and assist in the GMAC's ongoing role in the statutory review process.

Heating Our Buildings Efficiently

The only meaningful way the Commonwealth will meet its net zero emissions mandate is by transitioning all of our energy needs to electricity and then creating that electricity with renewable energy. This is a vast undertaking. It will mean:

1. Moving the vast majority of our transportation and building energy use to electricity
2. Upgrading our electric grid to meet the much higher demand
3. Generating that electricity with renewable energy and sourcing enough storage to deliver that electricity in a non-intermittent way

www.HEET.org | info@HEET.org | 516.900.4338 | 50 Milk Street | Boston, MA 02109

Although these tasks are large and complex, it is urgent we move forward as quickly as possible.

The Electric System Modernization Plans (ESMPs) are concerned with just the second part of that transition, that of upgrading the electric grid to meet the higher electricity demand. This comment letter points out that the more efficiently we perform the first step –specifically how efficiently we heat and cool our buildings– the less we will need to upgrade our electric grid and the less renewable energy and storage we will need. Furthermore, thermal energy is a key and often unmeasured component of the renewable energy transition which, when delivered by networked geothermal (and by single building installations of ground source heat pumps) has the potential to address intermittency, load shifting, and long duration storage challenges.

In summary, if our buildings are heated (and cooled!) with maximally efficient technologies, the second two steps are easier and the transition can happen faster, more equitably and for a lower cost.

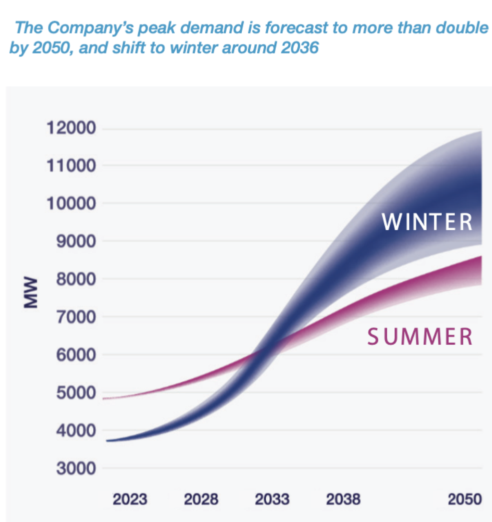
Electric Utilities' Dilemma - A Massive Upgrade and Higher Peaks

The gas distribution system in the Commonwealth on the coldest days of the winter holds four times the energy that the electric grid currently can hold at any point in the year. For the majority of the state's buildings to move off of gas to electricity, the electric grid will need to be upgraded significantly to deliver that much more energy.

Given the expected rate of the electrification of buildings, National Grid predicts in just over a decade (2036) winter electric peaks in the Commonwealth will be higher than summer electric peaks. By 2050, according to National Grid's prediction, the winter peaks will be three times higher than they are today.

National Grid expects winter peaking to start in MA by 2036

National Grid Future Grid Plan 9/23 - Section 1, Pg 9



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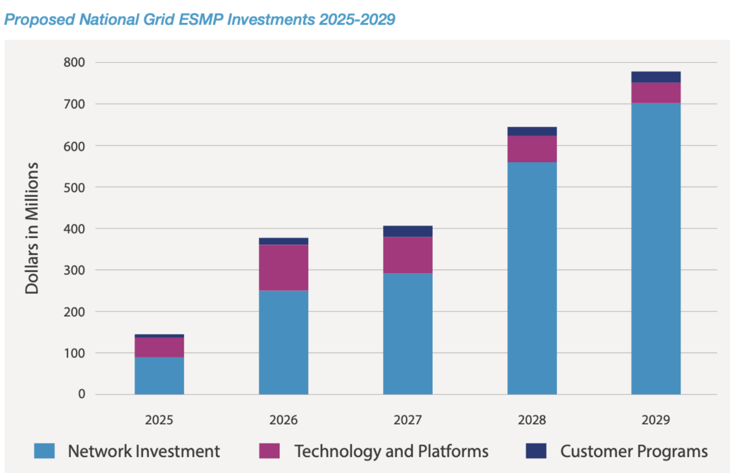
To pay for the upgrades needed for this sort of increased electric use, National Grid forecasts by 2029 it will need to invest annually by 2029 nearly eight times what it currently invests each year in the electric grid.

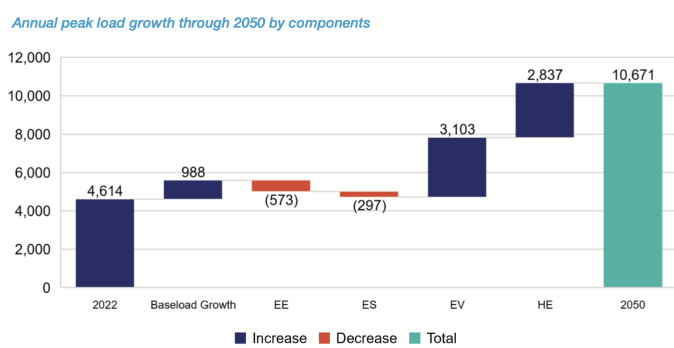


National Grid expects system upgrade investments to increase almost 7-fold to $800 million/year by 2029

National Grid Future Grid Plan 9/23 - Section 1, Pg. 12

Eversource does not show this sort of increase in service upgrade but does point out in its ESMP report that a significant number of its urban substations have already reached capacity and thus there will need to be upgraded or additional substations. Siting new or larger substations in metropolitan areas is never an easy, inexpensive or fast task.

Of course under the current regulatory framework all of these investments will, in the end, be paid for by customers. They will also have to pay for costs associated with the electric peaks. All of this will increase electricity costs for customers across the Commonwealth.



National Grid's ESMP report predicts that the need for heat ("HE" or Heating Electrification) will make up nearly half (2,837 out of 6057) of the electric grid growth by 2050.

National Grid Future Grid Plan, Sept. 2023. Page 28.

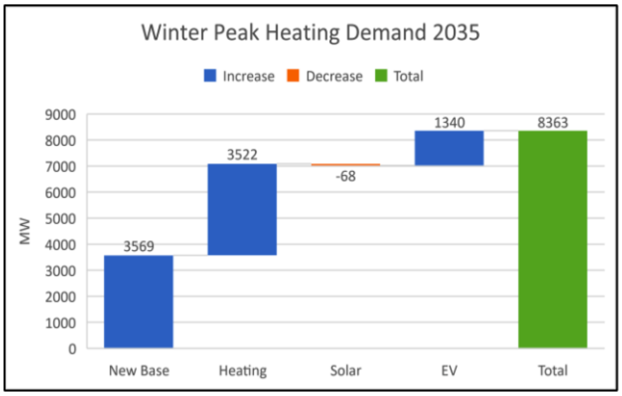


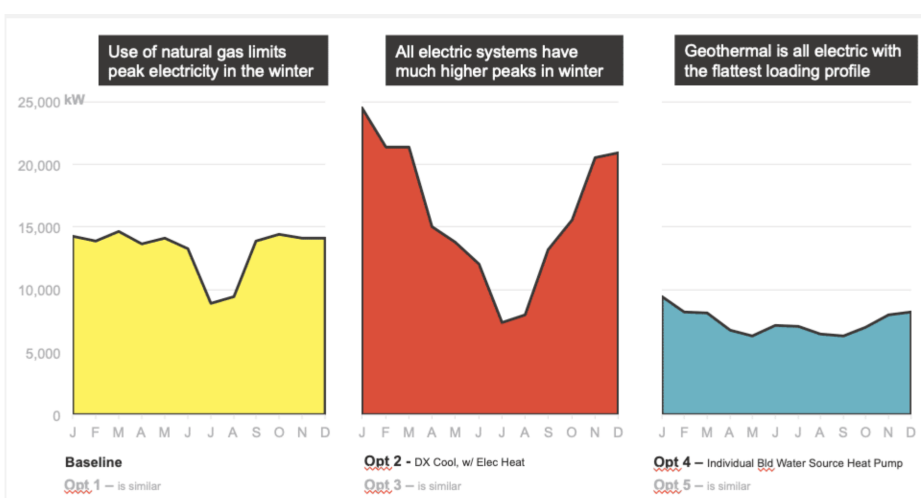
Figure 100: 2035 MA Winter Peak Make Up

Eversource found that heating electrification will be responsible for 73% of the increased winter peak by 2035.

Eversource Electric Sector Modernization Plan, Sept. 2023. Page 228.

Electric peaks are generally when the dirtiest and most expensive power plants are turned on and are thus the most expensive and the dirtiest electricity used in the Commonwealth. As we move to building electrification, those electric peaks will increase. Thus the efficiency of the method we use to transition our buildings matters enormously.

Single building installations of ground source heat pumps are roughly twice as efficient as air source heat pumps. This efficiency is because ground source heat pumps pull temperature from the ground below the frost line, where the temperature does not vary in the same way that the temperature of the outside air does and because the bedrock is a thermal battery that provides thermal storage. One analysis of a 2,300 unit installation in Yampa Valley in Colorado found that the single day electric peak loads from all the buildings being on air source heat pumps would be 250% more than networked ground source heat pumps.[1]



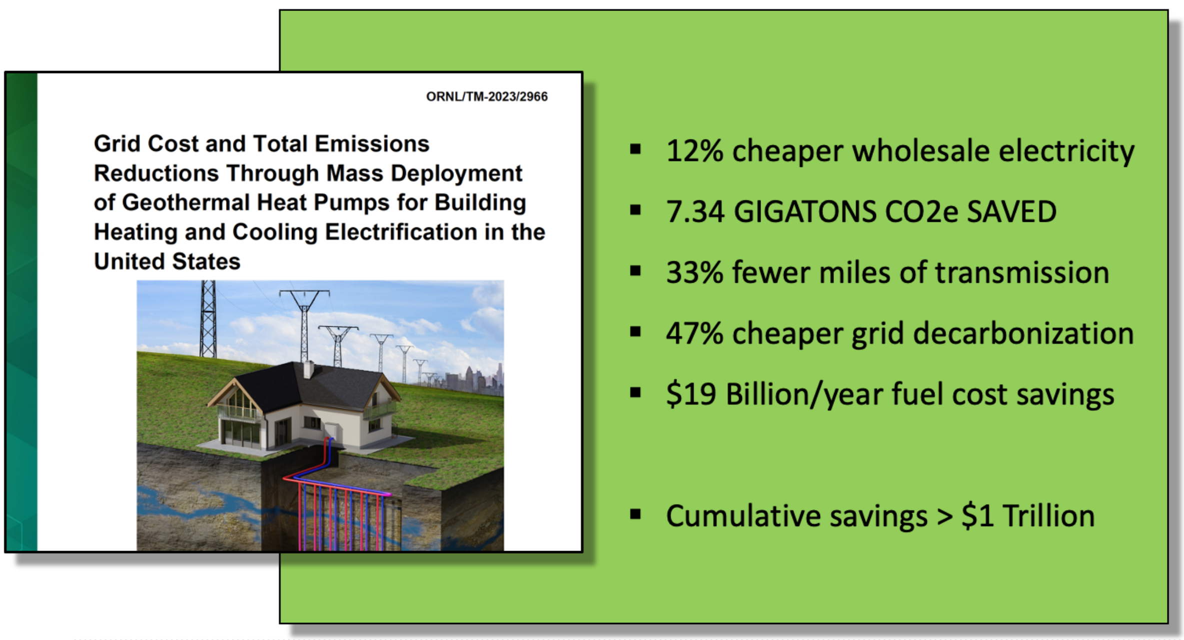
Yampa Valley development in Colorado projection of gas vs air source heat pumps vs geothermal (ground source

[1] https://www.steamboatpilot.com/news/is-a-geothermal-system-right-for-the-brown-ranch/

heat pumps). https://www.steamboatpilot.com/news/is-a-geothermal-system-right-for-the-brown-ranch/

Massachusetts winter electric peaks doubling (as National Grid projects) the size of the current summer peaks are thus quite likely to mean a significant increase in the cost per kWh, in addition to the costs from the electric grid system upgrades, such as new substations, needed to deliver that electricity. All of these costs will of course be borne by the customers. Is there any way to reduce the cost of the new substations and other upgrades, as well as the cost of the electricity used during the much higher winter electric peaks?

Oak Ridge National Lab just released a major report showing that single building installations of ground source heat pumps can be considered a service to the electric grid in terms of the way it reduces emissions and the costs of decarbonization.[2] This report indicates that an all U.S. mass deployment of Ground Source Heat Pumps (GSHPs) most notable result is "*that GHPs are primarily a grid-cost reduction tool and technology that, when deployed at scale, also substantially reduces CO2 emissions, even in the absence of any other decarbonization policy*."



A summary of the Oak Ridge National Lab analysis of the U.S. electric grid impact of wide scale deployment of ground source heat pumps. Report released on Dec. 6th, 2023.

[2] Grid Cost and Total Emissions Reductions Through Mass Deployment of Geothermal Heat Pumps for Building Heating and Cooling Electrification in the United States, Oak Ridge National Lab, Nov 2023 - https://info.ornl.gov/sites/publications/Files/Pub196793.pdf.

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In terms of Massachusetts-specific impacts, this same Oak Ridge analysis finds there would be a 36% reduction in electric load and distribution losses with a wide scale deployment of ground source heat pumps.[3] Such an impact, in HEET's opinion, must be considered in the ESMP.

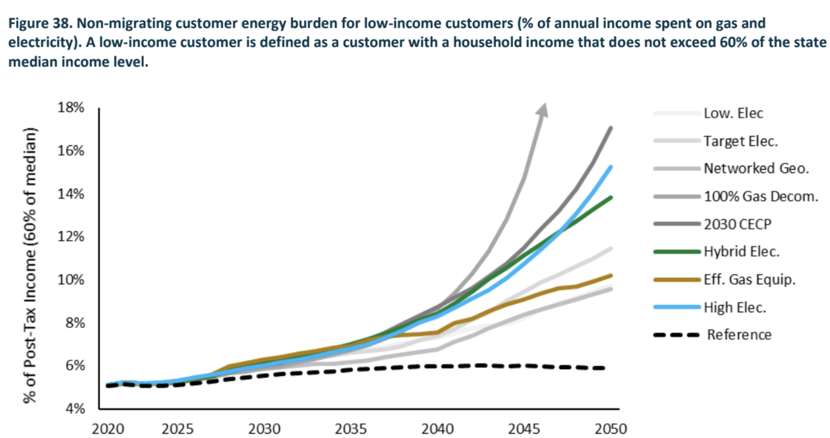
Gas Utilities' Dilemma - Replace Unsafe Pipes and Create Stranded Assets?

Given that:

- The Massachusetts 2050 Decarbonization Roadmap states that one million customers must transition to air source heat pumps by 2030 to achieve the state's net zero emissions mandate by 2050
- Air source heat pumps are now outselling gas furnaces across the country[4]

The gas customer base in 2050 is likely to be much smaller than it currently is and each remaining customer is likely to use significantly less gas per year given the increasing efficiency of gas appliances.

Each customer leaving the gas system does not mean that that system is any smaller or less expensive. The fixed costs of operating the system have not decreased in any way but must be shared among fewer and fewer customers over time, meaning that the remaining customer over time will pay a higher and higher price per therm delivered.[5]



DPU 20-80's independent Analyst found that the energy burden under the pathways modeled would increase significantly for the low income customers remaining on the gas system.

[The Role of Gas Distribution Companies in Achieving the Commonwealth's Climate Goals, Independent Consultant Report](), Fig. 38

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[3] From email correspondence with the study authors.

[4] Chart: Americans bought more heat pumps than gas furnaces last year, Feb. 2023. https://www.canarymedia.com/articles/heat-pumps/chart-americans-bought-more-heat-pumps-than-gas-furnaces-last-year

[5] Who Will Pay for Legacy Utility Costs? Lucas Davis et al. Energy Institute at Haas. Revised January 2022 https://haas.berkeley.edu/wp-content/uploads/WP317.pdf

In the end, the only customers remaining will be those who cannot afford a new heating system, as well as renters (who do not have the choice of switching out the heating system). The Germans call this “the last granma” problem where they imagine one last hypothetical grandma on the entire gas system. That hypothetical grandma will not be able to afford many gas workers to take care of the system, so it is likely the system will not be maintained and safety could be compromised also. This is not the sort of just transition any of us would desire.

The result of course will be stranded assets that are likely to have to be paid for by the Commonwealth and its taxpayers. This combined with the higher electric bills caused by higher electric peaks, as well as electric system upgrades, would be disastrous for many low to moderate income customers.

Meanwhile however the gas utilities are mandated for safety by state and federal legislation to replace aging and leakprone gas pipes. Currently, as part of the Gas System Enhancement Program (GSEP), the gas utilities are currently still pouring over $800 million per year into installing brand new gas pipes to replace the leak prone and aging gas pipes. The GSEP program is currently assumed to last through 2039 and (given the sheer mileage of National Grid’s replacement work, it might last longer). These new fossil fuel pipes are paid by customers through depreciation over decades. The total cost of the GSEP program from today until the end of the program has recently been predicted to be over $34 billion and not to be paid back entirely until 2097 (see attached ppt).[6] This calculation was derived using the “Future of Gas” Independent Consultant Reports.

While the GSEP working group is tackling some of these issues, it cannot be overstated that without extensive reform in the near future the predicted erosion of the gas customer base, combined with the vast GSEP payback, seems destined for disaster. As fewer customers share the fixed costs of the operations and maintenance of the infrastructure, as well as the costs of the vast GSEP program, there will be an inflection hit where heating with gas will cost more than heating with air source heat pumps. At that point, the speed of customers leaving the system will increase significantly.

The Department referred to the problem of these future gas infrastructure investments in last week’s final order for the Future of Gas proceeding. “In this “beyond gas” future, we [the Department]will be exploring and implementing policies that are geared toward minimizing additional investment in pipeline and distribution mains and achieving decarbonization in the residential, commercial, and industrial sectors.” D.P.U. 20-80-B, at 14. The Department will “require the examination of non-gas pipeline alternatives (“NPAs”), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response,

[6]GSEP’s cumulative costs as derived from the “Future of Gas” Independent Consultant Reports, Dorie Seavey, PhD. 20 October 2023, GSEP Working Group.
https://www.mass.gov/doc/seavey-gsep-cost-presentation/download

and behavior change and market transformation. Going forward, LDCs will have the burden to demonstrate the consideration of NPAs as a condition of recovering additional investment in pipeline and distribution mains." Id. at 15.

As the Department has laid the beginning of this framework for the "beyond gas future" it also acknowledges the massive undertaking, the necessary changes in law required for it to effectively regulate, and to do so safely and equitably in furtherance of climate change mandates.

Can GSEP be Part of the Answer?

HEET suggests the idea that the GSEP could actually help move customers to electricity and reduce future electric peak load.

Transition Gas Utilities into an Electrification Accelerant

Both National Grid and Eversource Gas are currently installing networked ground source heat pumps ("networked geothermal") as a possible alternative business model. Networked geothermal pumps ambient-temperature water (generally between 40 and 90 degrees Fahrenheit) down the street, buildings connected to the loop pull temperature off the water using heat pumps. There are attached closed vertical boreholes that the water can be sent through to return it to the temperature needed for heat pumps to work at their maximum efficiency. This acts like a big sealed radiator for thermal energy exchange with the bedrock. Shed thermal energy (such as the heat rejected by an ice rink during the winter) can be used by other buildings down the street. Additionally excess heat during the winter can be stored in the bedrock until needed in the winter.

Because of both the re-use of the shed thermal energy, as well as the thermal storage capacity of both the water mass in the pipes and in the thermal mass of the bedrock, networked geothermal is even more efficient than ground source heat pump systems that are not networked. A recent independent analysis by Xcel Energy (see attached report) of the 15-year-old networked geothermal installation at Colorado Mesa University found an average annual efficiency (or COP[7]) for the entire system that is roughly six times more than most gas boilers, and two to three times higher than the average air source heat pump. During the winter months, the seasonal COP was 8.9 in part because the heat stored in the bedrock during the summer is being used.

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[7] Coefficient of Performance or COP is a method of measuring the ratio between the units of energy fed into a system and the units of useful energy delivered.For every 1 unit of energy fed into a gas boiler, there is less than one unit of energy delivered because some of that heat goes up the chimney. An air source heat pump on the other hand uses nearby existing heat into or out of a building. Because it does not have to create the heat, but only move it, it is able to deliver 2 to 3 units of useful heat for every one unit of energy used.

Table 1 CMU networked geothermal efficiency vs a standard system

	Networked Geo COP	Conventional COP
Spring	7.0	1.9
Summer	3.6	3.4
Fall	5.8	2.0
Winter	8.9	1.2
Overall	**5.7**	**1.9**

A recent independent analysis by Xcel Energy found an annual average COP of 5.7 and a winter seasonal COP of 8.9 for the networked geothermal installation at Colorado Mesa University.

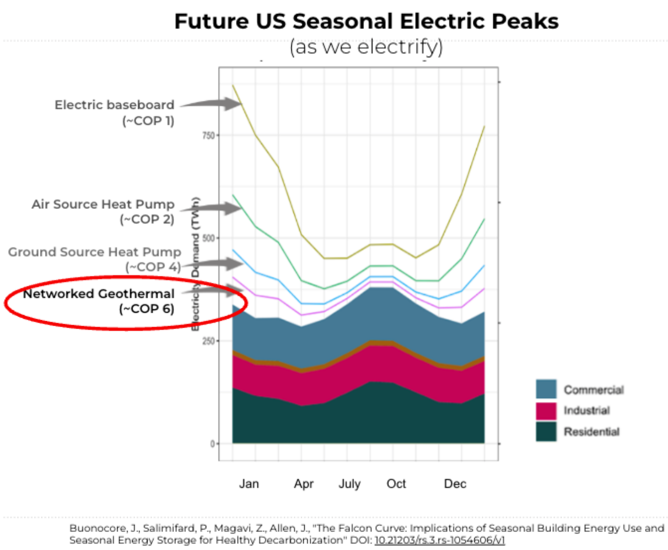
How We Electrify Matters

The method we use to electrify our buildings matters. The more efficient it is on average, especially during the winter, the lower those electric peaks will be (see the US Seasonal Electric Peaks graph below) and the less the electric utilities will have to upgrade the system to meet it. Both will reduce costs for customers, while allowing us to reduce emissions faster.

The Department of Public Utilities (the "Department") in approving the above mentioned networked geothermal projects found that "networked geothermal projects (1) have the potential to significantly reduce GHG emissions and (2) geothermal demonstration projects designed to test the effectiveness and scalability of utility-owned geothermal networks have the potential to reduce current barrier to widespread adoption in furtherance of the Commonwealth's climate policies. D.P.U. 19-120, at 139.

Taking this one step further in adopting its regulatory framework for how the LDCs will contribute to helping the Commonwealth achieve its 2050 climate change goals, it specifically recognized networked geothermal as having "the most potential to reduce GHG emissions." D.P.U. 20-80-B at 2. The Department went on to say it "welcomes networked geothermal and other targeted electrification technologies in particular as promising decarbonization strategies and will require each LDC to identify pertinent demonstration projects in each of its service territories." Id. at 79. Specifically, in laying out its regulatory framework and understanding some of the constraints placed on the LDCs the Department recognized that it will be critical for the LDC and EDCs to work together to ensure effective electrification, and directed direct collaboration on specific targeted electrification projects. Id. at 87.

This framework is laying the foundation for the necessary work to have a cost-effective, resilient, and equitable electrification in furtherance of the Commonwealth's decarbonization goals.



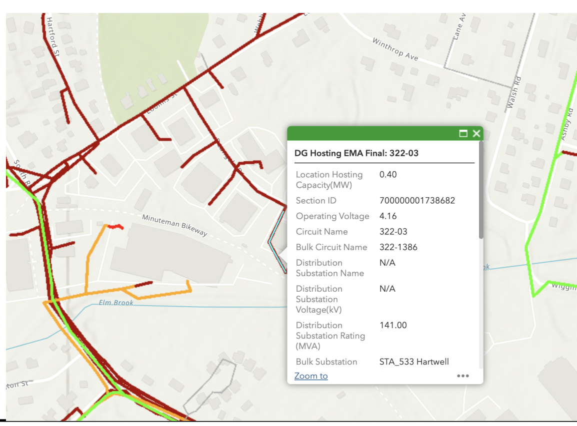
A recent peer reviewed study in the journal Nature Scientific Reports projected the future U.S. seasonal electric peaks with different electrification technologies if 100% of U.S. buildings used that technology.

Networked geothermal with its high COP would reduce the winter peaks the most.

Buonocore, J.J., Salimifard, P., Magavi, Z. *et al.* Inefficient Building Electrification Will Require Massive Buildout of Renewable Energy and Seasonal Energy Storage. *Sci Rep* 12, 11931 (2022). https://doi.org/10.1038/s41598-022-15628-2

Recommendations

- **Map an electric and gas integrated plan that is street-segment based and phased**
  The transition from gas and other fossil fuels to electric heat will profoundly impact the electric grid and the local electric utilities in every way. We need integrated gas and electric planning that is street-segment based and phased to maximize speed and reduce cost and disruption. Mapping street-segment future investments into gas and electric infrastructure (some examples shown below), building stock, geology, energy use intensity, Justice40 areas[8] and any other data layers necessary will help create the phased plan we need toward the fastest, most equitable, and least expensive method to transition.



National Grid and Eversource's electric grid constraint map shows local street segment capacity. The buildings along streets with electric constraints can be transitioned less expensively to electricity if they are moved to networked geothermal.

National Grid's electric grid constraint map

Eversource's electric grid constraint map

[8] I.e. communities that are disadvantaged according to the Justice40 initiative criteria. https://www.arcgis.com/home/item.html?id=bdac3e391cd04d2396983fc67c23bf1c

The gas utilities' GSEP filings state the street segments that are leakprone, when they will need to be replaced and what the costs will be. Instead of installing new gas pipes, installing networked geothermal would transition GSEP streets to electricity, without the Commonwealth (and taxpayers) having to pay for the work. There are roughly 200,000 customers along the 3,700 miles remaining miles of GSEPleakprone gas pipes. If these streets are transitioned to networked geothermal, the future electric peaks for the local areas would be reduced.

Town Name	Town Code	WONUM	DESCRIPTION	Prioritization Factor	Cost Estimate	GSEP Footage
Beverly	BEV	1248833	122-162 PARK ST, BEV, & 13-19 CREEK ST	15.80	$1,016,198	2,410
Beverly	BEV	1347809	3-148 NEW BALCH ST, BEV	14.19	$1,121,975	2,490
Beverly	BEV	1438444	3-15 CONGRESS ST, BEV, & 5-39 PORTER ST, LINDEN	29.86	$1,804,387	2,985
Beverly	BEV	1347862	3-53 WILLIAMS ST, BEV, & 15-17 GUILD RD	14.00	$656,724	1,345
Beverly	BEV	1248859	657-726 HALE ST, BEV	47.62	$1,305,860	2,670

Exhibit NG-GPP-4 2024 Boston Gas GSEP Proactive Main Work Orders, 23-GSEP-03

Substation Name or Location	Community Supplied	2030 % of Substation Capacity	Project Solution (Refer to Sections 6.5.1.2 and 6.5.1.3)
			Additions
Hyde Park	Jamaica Plain, Mattapan, Roslindale, Hyde Park	104	Future Hyde Park – Dorchester Area Supply Initiatives
Dorchester	Dorchester, Mattapan	100	Future Hyde Park – Dorchester Area Supply Initiatives
Everett	Charlestown	99	Charlestown/East Boston Substation
(LMA)	Fenway, LMA, Mission Hill, Jamaica Plain	98	Allston/Fenway/Brookline Substation
West Roxbury	West Roxbury	97	Future Hyde Park – Dorchester Area Supply Initiatives
Bay Village	Downtown, Back Bay	97	Metro Boston Substation Supply Initiative
Brighton	Allston, Brighton	96	Bulk Distribution Transformer Additions

These areas listed by Eversource in its ESMP as having little substation capacity would be ideal to consider for networked geothermal installations.

Eversource's networked geothermal installation in Framingham will actually reduce the electric constraints of the area because some of the customers connecting are electric baseboard customers which is much less efficient than networked geothermal.

Eversource Electric Sector Modernization Plan, Sept. 2023. Page 309

- **Allow electric utilities to use avoided costs to pay for customer retrofits**
  With both the Eversource and National Grid networked geothermal installations, nearly 100% of the eligible customers contacted agreed to connect to the networked geothermal systems. This is understandable since the installations provide heating as well as cooling, and improve indoor air quality in comparison to combustion heating. This high percentage of customer acceptance demonstrates the potential for the

majority of customers to choose to transition if the customer retrofits are free. Thus allowing electric utilities to use avoided costs to pay for customer retrofits on streets where networked geothermal is about to be installed might at times be a wise use of funds. In many places it might be less expensive for electric utilities (and their customers) to pay for customer retrofits than substations as well as electric system upgrades and higher electric peak loads. As the ESMPs should serve as the central distribution planning document, and as the data grows on customer adoption, there should be intentional coordination with the Energy Efficiency Advisory Council in the next three year plans to have appropriately targeted and nuanced incentives.

- **Allow gas utilities to become non-combusting thermal utilities**
  Allowing gas utilities to install non-combusting thermal infrastructure (like networked geothermal) and to sell thermal energy would allow them to redirect gas-upgrade funding in a way that would help the state meet its emissions mandates. This would allow the gas utilities to invest some (or all) of the $34 billion GSEP dollars transitioning customers to clean electricity using a method that would reduce the impact on the electric grid. The utilities' "obligation to serve" also needs to be able to be met using thermal service.

- **Merge the gas/networked geothermal ratepayer base to stabilize it** and to avoid reduced gas customer base creating rising gas customer bills (since there will be fewer customers paying for the same-sized system with its fixed costs). Merging the gas and geothermal ratepayer base would allow customers to transition from gas to thermal system while staying in the same ratepayer base, keeping that critical ratio the same of customers to infrastructure.

- **Change electric rates for heat pump owners**[9] to reward customers for emissions reductions, reduced electric peak and improved load factor and to allow low income customers to transition without being penalized.

- **Begin to measure and report on the thermal energy** delivered and stored in order to understand the thermal transition and quantify thermal sources such as ambient air, geothermal, waste thermal and more. We measure wind and solar energy, but we don't measure thermal energy, yet every heat pump deployed is capturing and delivering more thermal energy than electric energy. Uncovering and quantifying this aspect of our energy transition is essential for optimization.

The result of these actions can create a phased and detailed plan to meet our net zero emissions goal, allowing us to move forward strategic electrification at the speed and scale we need for the least cost and with less disruption.

[9] Heat Pump–Friendly Cost-Based Rate Designs, Energy Services Integration Group, Jan 2023 https://www.esig.energy/wp-content/uploads/2023/01/Heat-Pump%E2%80%93Friendly-Cost-Based-Rate-Designs.pdf

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With gratitude,

Audrey Schulman
Co-founder and Co-executive Director, HEET

Attachments:

- GSEP's cumulative costs as derived from the "Future of Gas" Independent Consultant Reports Dorie Seavey, PhD 20 October 2023 GSEP Working Group. https://www.mass.gov/doc/seavey-gsep-cost-presentation/download
- Xcel Energy's report on Colorado Mesa University's networked geothermal installation
- Grid Cost and Total Emissions Reductions Through Mass Deployment of Geothermal Heat Pumps for Building Heating and Cooling Electrification in the United States, Oak Ridge National Lab, Nov 2023 - https://info.ornl.gov/sites/publications/Files/Pub196793.pdf

EVALUATING A COMMUNITY GROUND SOURCE HEAT PUMP SYSTEM AT COLORADO MESA UNIVERSITY

SUMMARY

Colorado Mesa University (CMU) is in Grand Junction, Colorado, serves approximately 11,000 students, and spans 141 acres. This campus consists of 37 buildings including admissions, dormitories, athletics, academics, and student centers.

Beginning in 2008, CMU began deploying a geothermal loop system to reduce the need for conventional cooling and natural gas heating and reduce overall campus water use. The system was designed to utilize water-source heat pumps to serve interior spaces with a closed geothermal loop that utilizes the thermal stability of the ground as a heat sink. The networked loop consists of five loop fields with 471 bore holes drilled to depths ranging from 375 to 600 feet. These loop fields can be utilized as a thermal energy source to mitigate on-peak demand by filling the bore holes with loop water during off-peak periods and discharging the bore holes during on-peak periods. In 2023 Xcel Energy commissioned Michael's Energy to analyze the performance of CMU's geothermal system.

Today, this system serves 1.2 million sq. ft. of building area across 16 facilities with a diversity of cooling and heating needs. The system is comprised of (7) 50-HP central loop pumps, 91 individual building pumps, 5 conventional cooling towers, 2 hydronic boilers, 21 water-to-water heat pumps, 962 water-to-air heat pumps, and a

sophisticated control system. This equipment is sized to meet a design cooling load of 3,113 tons and a design heating load of 2,728 tons.

It is important to note that the geothermal system wasn't designed to meet 100% of the load, 100% of the time. CMU strategically interconnected conventional assets that already existed as buildings were added to the network. These assets are intended to increase overall system efficiency. These sources include water-to-water heat pumps for domestic hot water needs and pool preheating, a heat exchanger that enables the facilities team to reject heat via irrigation water, and five conventional cooling towers to reduce loop temperatures. In the winter months when loop temperatures decline to less than 57°F, the hydronic boilers inject heat into the loop. There were no instances of boiler operation throughout the 2022/2023 heating season. Additional gas usage can be attributed to dormitory domestic hot water (DHW) heating because the water-to-water heat pumps aren't able to raise the temperature of the water high enough to meet designed supply temperatures (140 F). However, newer heat pump technology can potentially solve this problem.

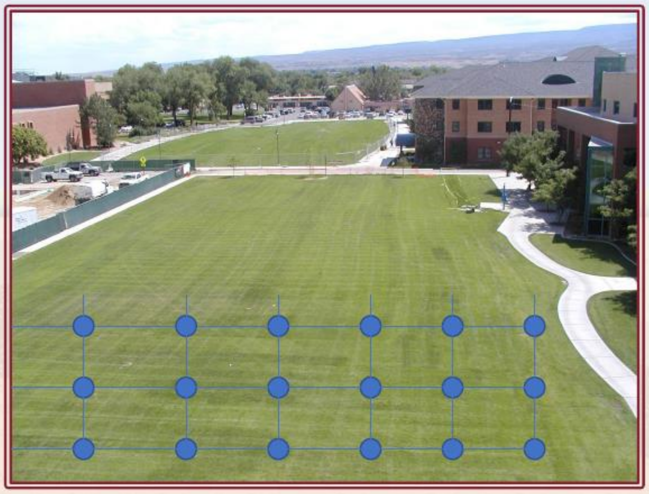
A key advantage of a network geothermal system is the system's ability to share heating and cooling loads. This load sharing can happen from room to room, floor to floor, and building to building. A water-to-air heat pump in heating mode removes heat from the building loop, cooling down the loop water. Another heat pump on the same loop in cooling mode expends less energy supplying space cooling than it would have otherwise. The same is true in reverse, where heat pumps in cooling mode reject excess heat into the building loop to be consumed by heat pumps in heating mode.

When comparing historical central campus loop temperatures versus outside air temperatures, it is apparent that this load sharing occurs when outdoor air temperatures are between 25°F and 55°F. This wide load-sharing operating band greatly increases the overall efficiency of the system as the need for heat pump compressor operation is greatly reduced.

When compared to a conventional cooling and heating system consisting of water-cooled chillers and natural gas hot water boilers, this system has a demand reduction of ~650 kW (13%), an energy savings of ~1.3 GWh (10%), a natural gas savings of ~58,000 Dth (55%), and a water savings of ~10 million gallons, annually. Water savings were provided by the Grey Edge Group and were not part of this analysis. Seasonal coefficient of performance (COP) values are displayed in Table 1, below. Note that a typical boiler operates with a COP of 0.8, a typical chilled water system at 3.4, and electric resistance heating at 1.0. A larger number indicates increased system efficiency and lower energy consumption per unit heating or cooling.

Table 1 CMU networked geothermal efficiency vs a standard system

	Networked Geo COP	Conventional COP
Spring	7.0	1.9
Summer	3.6	3.4
Fall	5.8	2.0
Winter	8.9	1.2
Overall	**5.7**	**1.9**



Drill field east and south of Dominguez Hall

Pipes connecting bore holes

8" dia. Pipes between Central Loop And H.H

Top: The drill field in front of Grand Mesa Hall

Right: A drill rig

18” diameter HDPE Central Loop

METHODOLOGY

Due to the large number of input assets that make up the Colorado Mesa University (CMU) Geothermal network, monitoring the system in empirical fashion would have proven cost and time prohibitive. Statistical regression analysis was used to discern power requirements and equipment performance in lieu of establishing automation system trend logs or taking onsite power measurements. The results are not an investment-grade analysis but provide a realistic understanding of overall and seasonal system performance, when compared to conventional cooling and heating equipment.

DEFINITIONS

HX	Heat exchanger	WSHP	Water source heat pump
AHU	Air handling unit	kW	Kilowatt
CFM	Cubic feet per minute	GPM	Gallons per minute
HP	Horsepower	COP	Coefficient of Performance
EER	Energy Efficiency Ratio		

DATA GATHERING

- Historical hourly data from April 2022 to April 2023 was collected for weather, central loop temperature, and available loop assets.
- Loop assets include central loop water pumps, building pumps, bore field pumps, cooling towers, cooling tower pumps, irrigation heat exchanger (HX) pumps, water-to-water heat pumps, and water-to-air heat pumps.

- Additional data was collected on known asset values and building settings, such as heating capacity, cooling capacity, heating design temperature, and cooling design temperature.

ASSUMPTIONS

- Conventional cooling and heating equipment power and efficiencies were estimated based on ASHRAE 90.1 documentation.
- Assumptions include chillers (0.61 kW/ton), primary pumps (0.018 kW/ton), secondary pumps (0.026 kW/ton), cooling towers (0.059 kW/ton), condenser pumps (0.057 kW/ton), and AHU fan kW (812 kW).
- AHU fan kW was derived using the following methodology and conversion factors: 400 CFM/ton, 0.75 HP/1000 CFM, Supply Fan HP (0.3*Max loop load), Return Fan HP (0.12*Max Loop Load).
- The water source heat pump (WSHP) efficiency disaggregation was built based on conversations with campus staff and is as follows: 60% - 13 Energy Efficiency Ratio (EER), 10% - 13.5 EER, 10% - 15 EER, 10% - 16 EER, 10% - 18 EER.

EMPIRICAL DATA

- Empirical data, consisting of average loop temperature and outside air temperature, was utilized to determine the load sharing temperature range. This is the temperate range where different buildings connected to the central loop are sharing energy between themselves, and little additional source and sink energy is required from the bore fields or conventional equipment.
- Data revealed a load sharing range when outside air temperatures are between 25°F and 55°F.

CALCULATION METHODOLOGY

- Loop cooling loads were derived from the relationship between outside air temperature, system balance point, and the design cooling temperature.
- Loop heating loads were derived from the relationship between outside air temperature, system balance point, and the design heating temperature.

- Input asset power (kW) was calculated using regression analysis for the equipment that didn’t have historical trend data configured. These assets are outlined below.
    - Heat pump cooling kW was calculated through regression analysis. This regression was built based on a load curve from a WSHP.
    - Heat pump heating coefficient of performance (COP) was calculated through regression analysis. This regression was built based on a load curve from a WSHP.
    - Cooling tower kW was determined through use of a second order polynomial regression, to model fan power between 85°F and the cooling design temperature.
    - Loop and building pump kW were determined through use of a third order polynomial regression, to model pump power based on a dual temperature loop load profile, assumed flowrate (GPM), assumed pump head, and pump horsepower.
- COP was calculated as a function of total loop load and input power.
- Total input power was determined by summing all input assets.
- Seasonal and overall system COP was evaluated for the geothermal system compared to a conventional water-cooled chiller system.

GSEP's cumulative costs

As derived from the "Future of Gas" Independent Consultant Reports

Dorie Seavey, PhD
20 October 2023
GSEP Working Group

Research question

Leaving aside GSEP's cost to date, how much are new GSEP investments likely to cost over time, fully loaded with return of capital costs and investor return?

Summary of results

$15.9 billion

Utility GSEP capital expenditures thru 2039

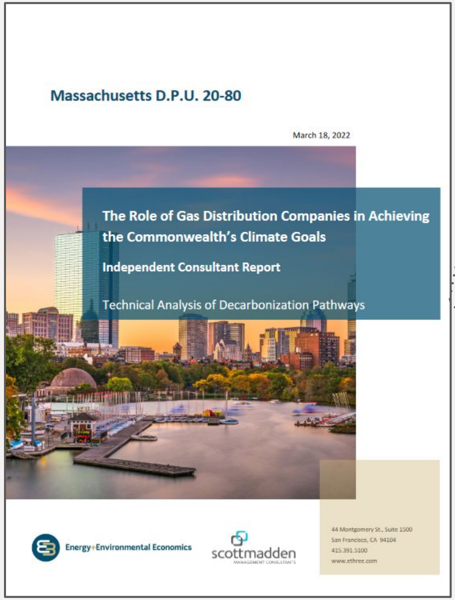
This is the forecast from the Future of Gas consultants with no adjustments.

$34.4 billion

Cost to ratepayers

Doesn't include O&M, property taxes (expressed in 2022 dollars)

How these figures were calculated



Final Independent Consultant Reports (3/18/2022)

- Part I: Decarbonization Pathways
- Part II: Regulatory Designs
- Appendix 1: Modeling Methodology
- Appendix 2: Literature Review
- Appendix 3: LDC Characteristics
- Appendix 4: Input Assumptions
- ERM: Future of Gas Stakeholder Engagement Process Report
- Eversource: Clean Energy Business Case Analysis

Total Forecasted GSEP Investments (Consultant Estimate)

Indicates values tied to GSEP filings

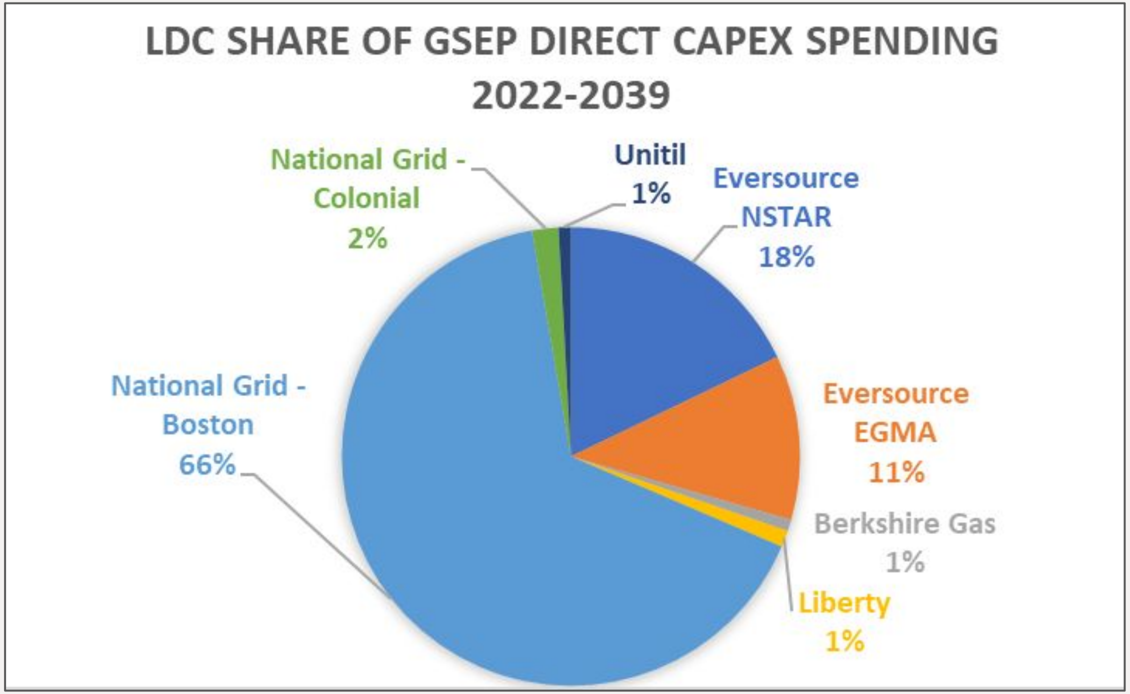
Indicates a forecasted value based on filed GSEP investments and the anticipated GSEP end year for each utility. Please refer to Appendix 1 for futher information on the Consultants' development of GSEP forecasts.

Miles of main replaced	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Eversource NSTAR	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	43	43	43
Eversource EGMA	35	40	45	45	45	45	45	45	45	45	45	40	34	-	-	-	-	-
Berkshire Gas	9	6	6	5	5	5	5	5	5	5	5	5	5	-				
Liberty	20	20	17	15	15	4	4	4	4	4	4	4	4	-				
National Grid - Boston	124	131	143	144	157	158	161	164	164	164	160	155	150	145	125	115	78	51
National Grid - Colonial	18	13	13	13	13	13	13	13	9	2	2	2	2	-				
Unitil	4	3	2	2	2	4	4	4	4	4	4	4	4					
Total	**255**	**257**	**271**	**269**	**282**	**274**	**277**	**280**	**276**	**269**	**265**	**255**	**244**	**190**	**170**	**158**	**121**	**94**

Total annual investment ($M - nominal)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Eversource NSTAR	$ 132	$ 126	$ 130	$ 133	$ 137	$ 142	$ 146	$ 150	$ 155	$ 159	$ 163	$ 168	$ 173	$ 178	$ 183	$ 182	$ 187	$ 193
Eversource EGMA	$ 97	$ 114	$ 132	$ 136	$ 141	$ 145	$ 149	$ 154	$ 158	$ 163	$ 168	$ 154	$ 135	$ -				
Berkshire Gas	$ 11	$ 9	$ 12	$ 8	$ 9	$ 9	$ 9	$ 9	$ 10	$ 10	$ 10	$ 11	$ 11	$ -				
Liberty	$ 28	$ 27	$ 24	$ 21	$ 22	$ 7	$ 7	$ 7	$ 8	$ 8	$ 8	$ 8	$ 8	$ -				
National Grid - Boston	$ 366	$ 398	$ 449	$ 493	$ 552	$ 573	$ 615	$ 633	$ 690	$ 712	$ 719	$ 718	$ 717	$ 757	$ 673	$ 641	$ 451	$ 303
National Grid - Colonial	$ 37	$ 26	$ 27	$ 30	$ 30	$ 31	$ 32	$ 33	$ 24	$ 6	$ 6	$ 6	$ 6	$ -				
Unitil	$ 9	$ 7	$ 6	$ 7	$ 6	$ 12	$ 12	$ 12	$ 13	$ 13	$ 13	$ 14	$ 14					
Total	**$ 681**	**$ 708**	**$ 780**	**$ 829**	**$ 898**	**$ 918**	**$ 970**	**$ 999**	**$ 1,057**	**$ 1,071**	**$ 1,087**	**$ 1,078**	**$ 1,064**	**$ 935**	**$ 856**	**$ 823**	**$ 638**	**$ 496**

GSEP capex forecast by Future of Gas Consultants, 2022-2039

$15.9 billion
in direct capex spending



Modeling assumptions for calculating cumulative costs

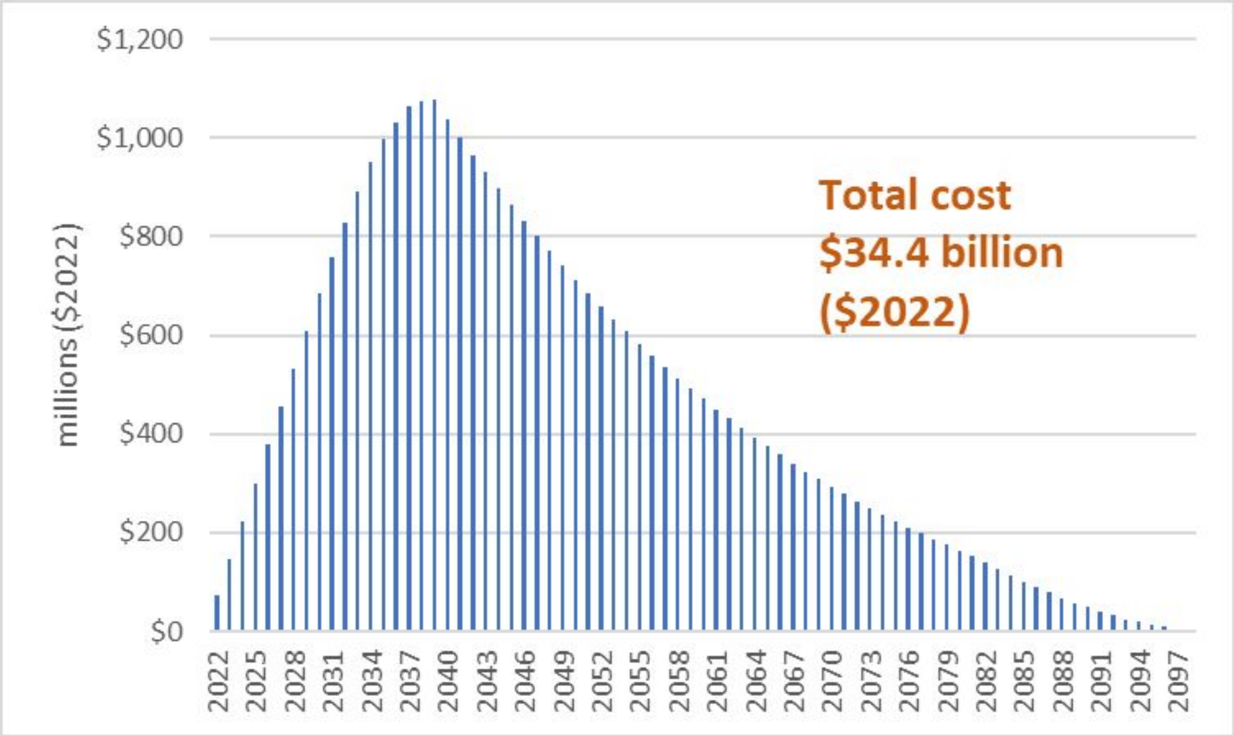
- **Replacement miles** and **gas capex projections,** as provided by FOG independent consultants
- **Actual pre-tax rate of return** for each LDC, weighted by LPP miles yet to be replaced under GSEP **(9.11%)**
- **GSEP end date**, as specified by each LDC
- **Straight-line depreciation** over 60 years (the average "whole life" for LDC mains per Appendix 4, weighted by LPP miles yet to be replaced)
- **2% escalation rate**

What's not included:

- Operations & maintenance expenses, property taxes
- Depreciation & return on investment for prior GSEP spending (2015-2021) – another $7.4 billion ($2022)

Results - Cumulative costs 2022-2039

Assuming 60-year depreciation, **the cumulative cost of remaining GSEP capex totals $34.4 billion ($2022),** with payback continuing through 2098.



Why are GSEP's cumulative costs important?

For a multi-decade spending program creating long-lived assets, **expected cumulative costs are critical for evaluating whether this spending is appropriate, economically and technically efficient, recoverable, and in the public interest.**

Cumulative cost reporting is essential for:

- ❑ Transparency
- ❑ Basic business management
- ❑ Capital efficiency
- ❑ Protecting ratepayers
- ❑ Informing long-term gas planning

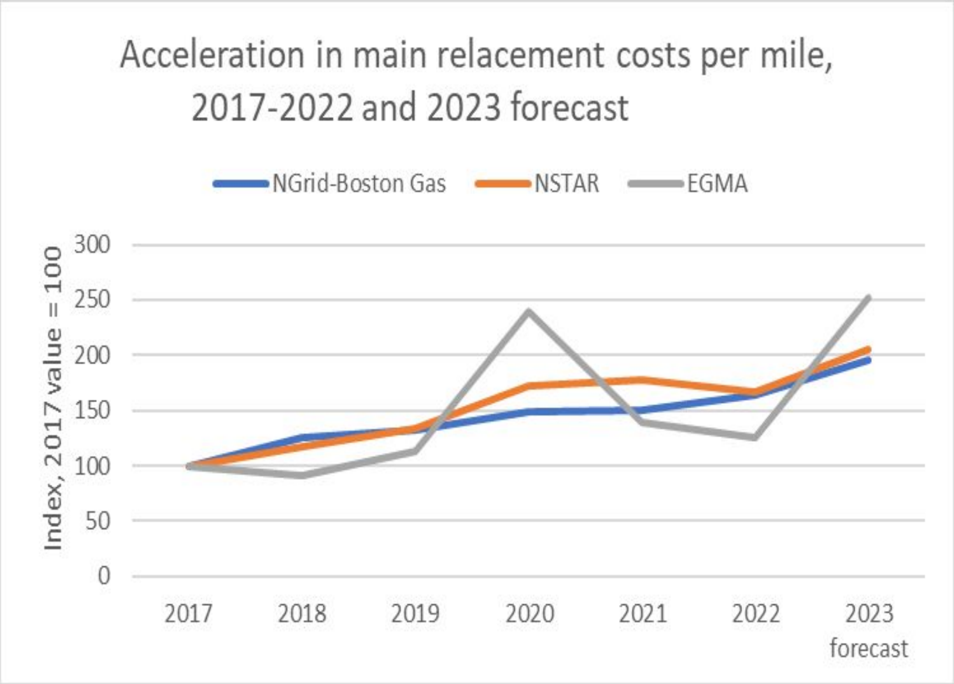
2023 GSEP: approved spending

Gas Utility	Proposed CY2023 GSEP spending (including advanced leak repair and G3SEI) (a)	Approved 2023 GSEP Revenue Requirement (b)	No. of main miles to be replaced in 2023 (c)	Actual average cost of main replacement (per mile) in 2022 * (d)
Unitil	$12,139,744	$4,496,531	6.3	$1,253,290
Berkshire Gas	$14,330,540	$2,101,545	10.4	$1,041,066
National Grid	$443,844,539	$131,414,093	130.0	$2,786,322
Liberty Utilities	$36,644,360	$20,234,054	19.7	$811,982
Eversource Gas Co.	$132,267,824	$37,709,277	43.0	$1,054,061
NSTAR	$177,250,022	$68,599,783	62.0	$1,689,369
TOTAL	**$816,477,029**	**$264,555,283**	**271.4**	**$2,068,194**

* Average main replacement cost across the 6 utilities is weighted by main miles replaced in 2022.

Sources: (a) and (c) are from various exhibits filed in Dockets 22-GSEP-01 to -06 (CY2023 GSEP Plan proceedings); (b) is from DPU's final orders concerning the CY2023 plan petitions; (d) is from various exhibits filed in the 2023 GREC (Gas System Enhancement Plan Reconciliation) proceedings (Dockets 23-GREC-01 to -06).

Significant unit cost escalation continues for largest LDCs



- **Per mile replacement costs have essentially doubled over the last 6 years.**

- **More difficult projects**: Larger LDCs anticipate rising costs due to focus on replacement activity in densely populated areas with congested roadways and layers of other underground utilities.

- **Spending cap**: 4 of the 6 LDCs hit their "GSEP spending cap" in 23-GSEP and asked to defer some recovery to future years. (Cap equals 3% of total firm revenues)

2023 GSEP spending on Grade 3-SEI leaks & advanced leak repair is de minimus

2.2% of total GSEP-approved spending ($18.3 million)

	Grade 3-SEI leaks	Advanced leak repair
NGrid-Boston	$1,958,642	$14,453,278*
NStar	$50,022	$1,500,000
EGMA	$303,490	
TOTAL	$2,312,154	$15,953,278

* Note: NGrid's advanced leak repair is directed at non-GSEP-eligible pipe only.

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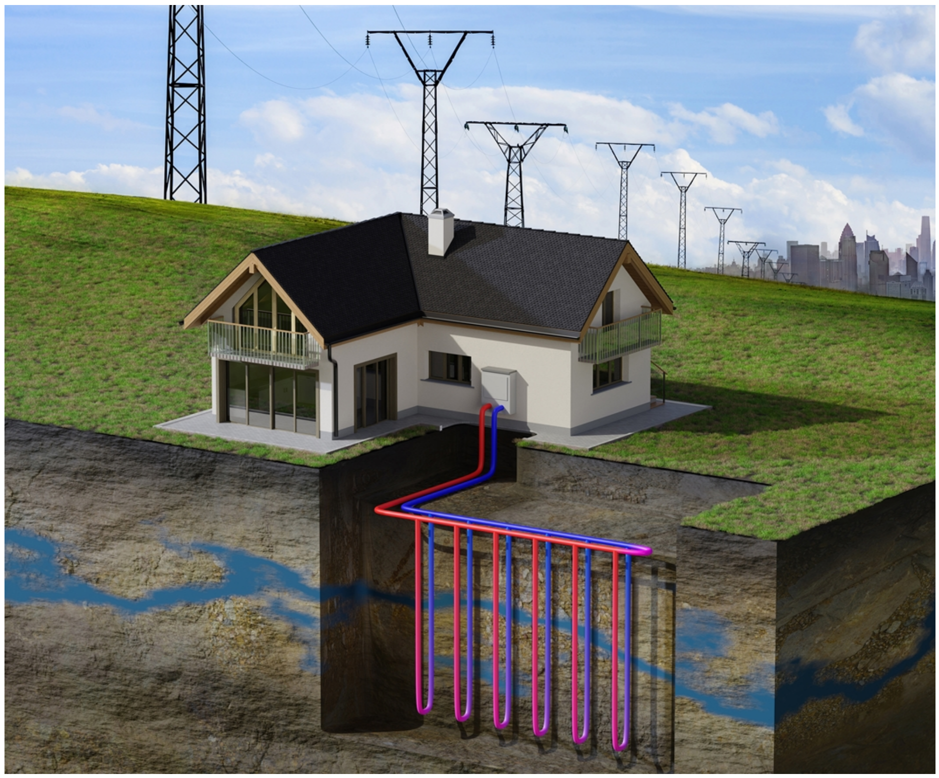
Groundwork Data offers advisory, research, and technology services to accelerate a clean, equitable, and resilient energy transition.

ORNL/TM-2023/2966

Grid Cost and Total Emissions Reductions Through Mass Deployment of Geothermal Heat Pumps for Building Heating and Cooling Electrification in the United States



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November 2023

OAK RIDGE
National Laboratory

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ORNL/TM-2023/2966

Energy Science and Technology Directorate

GRID COST AND TOTAL EMISSIONS REDUCTIONS THROUGH MASS DEPLOYMENT OF GEOTHERMAL HEAT PUMPS FOR BUILDING HEATING AND COOLING ELECTRIFICATION IN THE UNITED STATES

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November 2023

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ABBREVIATIONS

AEO	Annual Energy Outlook
AHRI	Air-Conditioning, Heating, and Refrigeration Institute
ANSI	American National Standards Institute
ASHP	air source heat pump
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
BA	balancing area
CEM	capacity expansion modeling
CO_2e	CO_2 equivalent
COP	coefficient of performance
CSP	concentrating solar power
CZ	climate zone
DOAS	dedicated outdoor air system
DOE	US Department of Energy
DX	direct expansion
EER	energy efficiency ratio
EFS	*Electrification Futures Study*
ERCOT	Electric Reliability Council of Texas
EULP	end-use load profile
GHE	ground heat exchanger
GHG	greenhouse gas
GHP	geothermal heat pump
H_2-CT	hydrogen combustion turbine
HVAC	heating, ventilation, and air-conditioning
IECC	International Energy Conservation Code
ISO	International Organization for Standardization
LMP	locational marginal price
MLP	multilayer perceptron
MMT	million metric tons
NERC	North American Electric Reliability Corporation
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NPCC	Northeast Power Coordinating Council
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
OA	outdoor air
ORNL	Oak Ridge National Laboratory
PCM	production cost modeling
PSH	pumped storage hydropower
PTAC	packaged terminal air-conditioner
PV	photovoltaic
RAZ	reliability assessment zone
ReEDS	Regional Energy Deployment System Model
SEER	seasonal energy efficiency ratio
SERC	SERC Reliability Corporation
SFH	single-family home
TMY3	third edition of typical meteorological year data
VBGHE	vertical bore ground heat exchanger
VRE	variable renewable energy

NOMENCLATURE

Item	Definition and explanation
Annual load (TWh)	Total electrical energy consumption at the point of use, including end-use demand and storage charging but not including losses between the points of generation and the points of use
Annual generation (TWh)	Total electrical energy generation, which is the sum of the loads at the points of use (including storage charging) plus the losses in delivering energy from the point of generation to the loads
Annual generation cost ($ billion)	Total electricity generation operational costs, including fuel and variable operation and maintenance cost
Annual generator revenue ($ billion)	Total payment for electrical energy in the wholesale market; equivalent to the sum of the product of locational marginal price and demand at each region
Average wholesale electricity price ($/MWh)	Average wholesale price that utilities paid for electricity to serve the annual load
Annual operating reserve provision (TWh)	Total hourly reserve capacity throughout the year
Annual unserved load (GWh)	Total unserved load, possibly because of maintenance, congestion, and so on
Annual peak demand (GW)	Peak demand throughout the year
RA eligible capacity (GW)	The portion of a generator or storage capacity that can be reliably counted on during a period of need ensuring resource adequacy
Generation capacity (GW)	The summation of all power plant nameplate capacities. The capacity of all plants is not always available (e.g., solar capacity at night, or when a power plant is in maintenance or shutdown). In this study, *generation capacity* also includes battery power capacity.
Battery capacity (GW)	The summation of the maximum amount of power that can be delivered by the batteries
Battery energy storage (GWh)	Total energy that can be stored in the battery
Emissions (MT or MMT)	Emissions of CH_4, CO_2, NO_x, and/or SO_2 that are released as the products of the combustion of fossil fuels at power plants or in buildings for space heating. Emissions from water heating for use in buildings were not evaluated in this study.
Annual fuel cost ($ billion)	Total generation cost associated with fuel consumption
Annual fuel offtake (TJ)	Total fuel energy (i.e., heat value) consumed for generation
Net demand (TW)	Electric demand minus renewable power generation
EULP	End-use load profile, which includes hourly electric and fuel consumption in an individual building or a cluster of buildings

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EXECUTIVE SUMMARY

This report presents the results of a study on the potential grid impacts of national-scale mass deployment of geothermal heat pumps (GHPs) coupled with weatherization in single-family homes (SFHs) from 2022 to 2050. GHPs are a technology readiness level 10, commercially available technology across the United States. This study is an impact analysis only; installed costs and available land areas for installing GHPs are not accounted for in determining their estimated deployment. The three scenarios studied were (1) continuing to operate the grid as it is today (the *Base scenario*), (2) a scenario to reach 95% grid emissions reductions by 2035 and 100% clean electricity by 2050 (the *Grid Decarbonization scenario*), and (3) a scenario in which the Grid Decarbonization scenario is expanded to include the electrification of wide portions of the economy, including building heating (the *Electrification Futures Study* or *EFS scenario*). The analysis team modeled each of these three scenarios with and without GHP deployment to a large percentage of US building floor space.[1] In all cases, deployment of approximately 5 million GHPs per year demonstrated system cost savings on the grid, consumer fuel cost savings through eliminated fuel combustion for space heating, and CO_2 emission reductions from avoided on-site fuel combustion—and, in the case of the Base scenario, CO_2 emissions reductions from the electric power sector.[2]

GHPs have traditionally been viewed as a building energy technology. The most notable result of this study, however, is the demonstration that GHPs coupled with weatherization in SFHs are primarily a grid-cost reduction tool and technology that, when deployed at a national scale, also substantially reduces CO_2 emissions, even in the absence of any other decarbonization policy.

Key Findings

GHPs widely deployed across the United States could result in the following key benefits.

1. Wholesale payments for electric grid services are reduced by at least $300 billion through 2050. This study evaluated the all-in electricity costs that are avoided by GHP deployment. Savings are 10% ($316 billion) in the Base scenario, 13% ($557 billion) in the Grid Decarbonization scenario, and 11% ($607 billion) in the EFS scenario. These reported numbers are the present-day value of future savings (at a 5% discount rate).
    a. For the Grid Decarbonization scenario, the undiscounted cumulative savings through 2050 are more than $1 trillion. This scenario has the effect of reducing the wholesale price of electricity by 12% (a $10/MWh price reduction).
    b. GHPs reduce the cost of meeting the Grid Decarbonization objective by 47% (a $632 billion undiscounted cost reduction) and by 27% including electrification (a $810 billion undiscounted cost reduction).
    c. Because GHPs reduce the cost of power on the grid, as well as the marginal system cost of electricity, which, combined with reduced fuel consumption, reduces consumer energy payments, GHPs are valuable for potentially achieving economic and environmental justice in underserved communities. Because less grid infrastructure investment is required with the large-scale deployment of GHPs, they could reduce the cost of power for *all* grid consumers—even those who do not have the technology installed.

---

[1] The modeling considered deployment across 68% of total building floor space in the contiguous US, which includes deployment to 43% of commercial and 78% of residential building floor space.
[2] In the Decarbonization and EFS scenarios, electric-power sector emissions are still avoided but are attributable to CO_2 policy drivers as opposed to the deployment of GHPs.

2. Consumer payments for heating fuels are reduced, resulting in a savings of $19 billion per year by 2050.[3]

3. CO_2 emissions are reduced cumulatively by 7,351 million metric tons (MMT) from 2022 to 2050 compared with the Base scenario, where 3,033 MMT reduction comes from the electric sector, and 4,318 MMT comes from the building sector (a 26% reduction in building sector emissions).

4. By the year 2050, 593 TWh/year[4] less generation is required in the Grid Decarbonization scenario, and 937 TWh/year less generation is required in the EFS scenario. These results represent reductions in overall generation requirements of 11% and 13%, respectively.

5. Even though building heating is electrified with GHP deployment—increasing winter electricity use for homes and businesses that otherwise are heated with fossil fuels—the increase is more than offset by the electricity savings from the high-efficiency performance of GHPs for summer cooling and reduced thermal loads owing to weatherization in single-family homes, resulting in substantial net reductions in grid generation, capacity, and transmission (see Figure ES-1).

6. The mass GHP deployment reduces transmission expansion requirements by 33% under the Grid Decarbonization scenario and by 38% under the EFS scenario. This amount equates to roughly 24,500 mi of transmission that can be avoided under the Grid Decarbonization scenario and nearly twice as much (43,500 mi) under the EFS scenario, which is enough to cross the average contiguous US coast-to-coast distance 9 and 16 times, respectively.[5]

7. Although outside the scope of the analysis described herein, key findings could lead to significant workforce and human health effects. The widespread GHP deployment modeled in this analysis would likely incentivize local job creation in the drilling and HVAC sectors across the US. The large emissions (e.g., CO_2, SO_x, and NO_x) reductions attributable to avoided on-site fuel combustion will similarly produce substantial local health benefits that would be realized across the country. Future work is planned to further quantify the magnitude of these benefits.

---

[3] This category covers all fuels purchased for use in building heating but does not include reductions in consumer payments for heating from electric resistance heaters (e.g., baseboard heaters). The fuel cost savings are calculated as all avoided on-site fuel combustion (natural gas, propane, and fuel oil) and using the forecasted price of natural gas of $3.26/MMBtu, conservatively ignoring higher costs for propane and fuel oil for heating. For comparison, the average trading price of natural gas for the last 5 years (including the disruptions caused by the COVID-19 pandemic and the war in Ukraine) has been over $3.50/MMBtu (NYMEX natural gas data 06/14/18 to 06/14/23).

[4] For comparison, 580 TWh/year is equivalent to the output of 66 1,000-MW nuclear power plants running 24/7, 365 days a year. The EFS scenario generation reduction is equivalent to 106 1,000-MW nuclear power plants running 24/7, 365 days a year.

[5] Transmission distances were determined based on a 36.7 TW·mi and 65.3 TW·mi reduction under the Grid Decarbonization and EFS scenarios, respectively, assuming a representative 1,500-MW line capacity and an average distance from the west to the east coast of 2,800 mi for the contiguous United States.

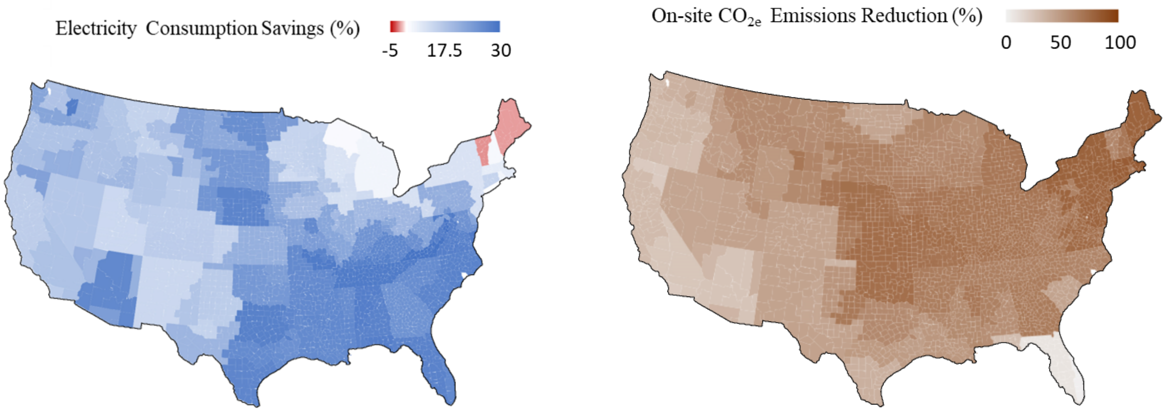


Figure ES-1. Geospatial representation of the percentage changes in (left) building annual electricity consumption and (right) carbon emissions (from on-site combustion in buildings) resulting from deploying GHPs into 68% of existing and new residential and commercial buildings in the United States, coupled with weatherization in single-family homes.

Background

Geothermal heat pumps (GHPs; also called ground source heat pumps) transfer heat to and from the ground by circulating water (or antifreeze solution in regions with cold climates) through underground piping. GHPs are well-understood to be beneficial for lowering building energy costs because of their high efficiency and ability to supply heat without fuel purchases. As a result, GHPs have zero on-site emissions. However, few studies have investigated the impacts on the electric grid of the large-scale deployment of GHPs.

This first-of-its-kind study simulates the energy use impacts of deploying GHPs into 68% of existing and new building floor space in the United States (78% of residential floor space and 43% of commercial floor space) in 14 climate zones[6] across the contiguous United States by 2050. Because this study is an impact analysis only, it does not examine the costs of and available land areas for installing GHPs in existing buildings or new constructions. Further analysis is needed to assess installation costs and needed land areas of the deployment scenarios presented in this study.

The results of this impact analysis demonstrate that savings in grid costs, CO_2 emissions, and building energy consumption are all significant. These results also demonstrate that when achieving mass deployment levels, GHPs coupled with weatherization in SFHs are primarily an electric grid cost-reduction tool and technology.

Modeling Scenarios

This study analyzed the impacts of mass GHP deployment on the electric grid through capacity expansion modeling and production cost modeling of the US electric power sector. The analysis includes a simplifying assumption that GHP deployments in this study were for individual buildings (not district-scale and/or networked systems). The building modeling accounted for weatherization in SFHs by reducing outdoor air ventilation to the minimum required by ASHRAE Standard 62.2 (ASHRAE 2007, 2016) and by eliminating air leakage from the ductwork of HVAC systems through air-sealing, which are commonly recommended practices in heat pump retrofits. According to previous studies, air-sealing can

[6] ANSI/ASHRAE Standard 169-2021 entitled *Climatic Data for Building Design Standards* (ASHRAE 2021) defines climate zones 1 through 8 as very hot, hot, warm, mixed, cool, cold, very cold, and subarctic/arctic, respectively, and sub climate zones A, B, and C as moist, dry, and marine, respectively, in several climate zones.

reduce heating energy consumption by 30%–50% (Chan 2013, Hassouneh et al. 2012, Jokisalo et al. 2009, Lozinsky and Touchie 2018, Pasos et al. 2020, Sawyer 2014). Deployment rates were fixed at 3.6% per year of existing and new building floor space that is considered applicable[7] for GHP in this study for 28 years until 2050. This study used four core scenarios.

- **Base scenario:** No GHP deployment occurs, energy consumption in new buildings between 2020 and 2050 is consistent with *Annual Energy Outlook 2021* projections (US Energy Information Administration 2021), and CO_2 emissions policies remain the same as existing state policies, including renewable portfolio standards, clean energy standards, and CO_2 emissions policies.

- **Base + GHP scenario:** The GHP deployment rate increases linearly from 0% in 2021 to 100% of all applicable buildings in 2050, which would amount to approximately 5 million GHP units installed per year. GHPs are included in new buildings starting in 2022, assuming the same energy savings as those for existing buildings.

- **Grid Decarbonization (or *Decarbonization*) scenario:** CO_2 emissions from the US electric power grid are reduced by 95% in 2035 and 100% in 2050 compared with 2005 emissions from the electric power sector.[8] This scenario indicates that all the power generation will use clean energy by 2050.

- **Grid Decarbonization + GHP scenario:** The impact of GHP deployment is incorporated into the Grid Decarbonization scenario using the same GHP deployment assumptions as the Base + GHP scenario. Both the grid decarbonization goal and the GHP deployment goal (i.e., deploying GHPs in all applicable new and existing buildings in the US) will be achieved in 2050.

Two additional scenarios were assessed in this study based on the EFS (Sun et al. 2020). These two scenarios use the same power system decarbonization pathways as the previous Grid Decarbonization scenarios.

- **EFS scenario:** No GHP deployment occurs, and economy-wide electrification of end uses—including partial building electrification through air source heat pumps (ASHPs), including the cold climate heat pumps, and other electrified devices for water heating and cooking—occurs, consistent with the values used in the high-electrification scenario from the EFS.[9] Weatherization in SFHs was not included in EFS.

- **EFS + GHP scenario:** An economy-wide electrification of end uses occurs, along with 100% GHP deployment in applicable existing and new buildings coupled with weatherization in SFHs.[10] Electrification of other end uses (not for heating and cooling) is consistent with the values used in the high-electrification scenario from the EFS.

[7] It covers all buildings included in the original end-use load profile (EULP) data set published by the National Renewable Energy Laboratory (NREL; NREL 2021), except for buildings that use district heating/cooling, mobile homes, buildings without heating or cooling, and buildings that already use GHP.
[8] The electric-sector CO_2 emissions cap is based on the decarbonization scenario in the US Department of Energy's (DOE's) *Solar Futures Study* (DOE 2021) and is consistent with the goals in *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050* (White House 2021).
[9] In the EFS scenario, ASHPs were assumed to be used in 68% of residential buildings and 46% of commercial space in the United States. It is also assumed that residential ASHP efficiency will increase by 116% from 2015 to 2050 in the rapid technology development case.
[10] ASHPs in the EFS scenario are replaced with GHPs.

Impacts of Widespread GHP Deployment

The modeled scenarios described previously revealed major impacts resulting from the mass deployment of GHP systems (i.e., deploying GHPs into 68% of residential and commercial buildings in the United States, coupled with weatherization in SFHs) by 2050 in the contiguous United States.

1. **Net reduction in annual electricity consumption and greenhouse gas (GHG) emissions:** The greatest electricity savings occur in the southeastern United States, and the greatest in-building emissions reductions occur in the northern United States, as shown in Figure ES-1.

   The deployment of GHP systems has different impacts in different geographic areas (Figure ES-1). Large reductions in annual electricity consumption in the southern United States occur, for example, because energy-efficient GHPs replace widely used conventional air-conditioning systems, which dominate total annual energy use in the region.

   In the northern United States, GHP deployment results in dramatic reductions in on-site carbon emissions because GHPs replace existing combustion-based heating sources (gas, propane, and fuel oil), which emit substantial GHG emissions and other pollutants. In many regions, the gain in efficiency from GHPs during the summer cooling season more than offsets the increase in electrified winter heating load. Furthermore, weatherization in SFHs also reduces thermal loads for heating and cooling, especially in cold climates. In aggregate, this combined solution (GHP and weatherization in SFHs) results in full building electrification with reductions in total annual electricity use in most parts of the United States.

2. **Reduced need for annual power generation:** Mass GHP deployment could reduce the required annual electricity generation in the contiguous United States[11] by **585 TWh** for the Base scenario, **593 TWh** for the Grid Decarbonization scenario, and **937 TWh** for the EFS scenario, as shown in Figure ES-2.

   The major difference between the impacts of GHP deployment in these scenarios is related to the types of generation being reduced. In the Base + GHP scenario, generation is reduced across all technology types with both thermal generation and renewable technologies. In contrast, in the Grid Decarbonization + GHP scenario, the net reduction is primarily attributable to reductions in variable renewable energy (VRE) generation, such as wind and solar, and hydrogen combustion turbines (H_2-CTs), with small increases in output from nuclear power plants. The EFS + GHP scenario sees the same reductions in H_2-CTs with an increased magnitude of VRE reductions. The shift in onshore wind generation in the EFS + GHP scenario is related to reductions in winter electricity consumption under EFS as a result of replacing ASHPs (including cold climate heat pumps) with GHPs coupled with weatherization in SFHs. More details are provided in Section 4.2.1.1 of this report.

[11] This excludes Alaska, Hawaii, and US territories because of limited data for conducting a detailed analysis.

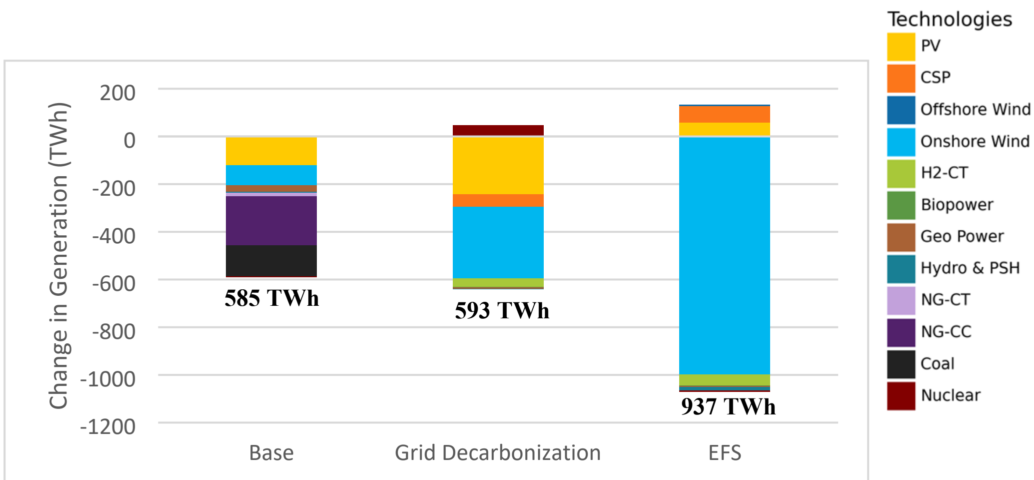


Figure ES-2. Changes in US annual electricity generation (TWh) in 2050 for Base, Grid Decarbonization, and EFS scenarios resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes. (CSP: concentrating solar power; H2-CT: hydrogen combustion turbine; NG-CC: natural gas combined cycle; NG-CT: natural gas combustion turbine; PV: solar photovoltaic; PSH: pumped storage hydropower.)

3. **Reduced need for power generation capacity and storage capacity:** Mass GHP deployment in the Grid Decarbonization scenario could double the reduction in installed generation and storage capacity achieved in the Base scenario (173 GW reduction in the Base + GHP scenario versus 345 GW reduction in the Grid Decarbonization + GHP scenario), as shown in Figure ES-3. In the EFS + GHP scenario, the installed generation and storage capacity was reduced by 410 GW.

   In the Grid Decarbonization scenario, more of the US generation mix is made up of VREs (74%–77% in the Grid Decarbonization scenario, compared with 43%–44% in the Base scenario). The Grid Decarbonization scenario also includes more battery storage than the Base scenario to improve the capacity factor of VREs. Therefore, the reduction in electricity demand resulting from GHP deployment has a greater impact on the Grid Decarbonization scenario. More details are provided in Section 4.2.1.1 of this report.

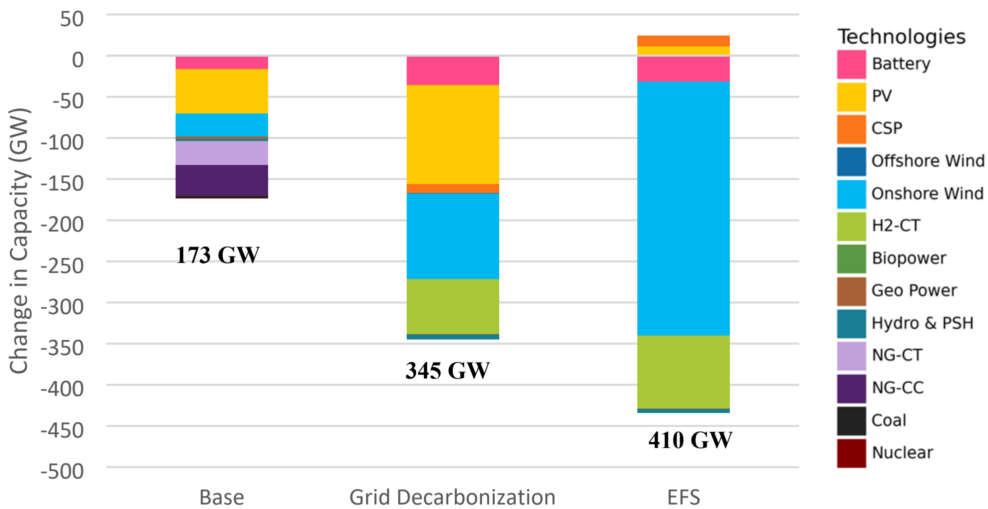


Figure ES-3. Changes in US installed power generation and storage capacity (GW) in 2050 for Base, Grid Decarbonization, and EFS scenarios resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes.

Mass GHP deployment coupled with weatherization in SFHs reduces the need for generation capacity compared with electrifying the building sector using ASHPs: Compared with electrification using ASHPs assumed in the EFS scenario, the mass GHP deployment could reduce the required electric power system capacity by 410 GW (from 3,568 GW to 3,158 GW) by 2050, as indicated in **Error! Reference source not found.**1.[12] Electrifying buildings using GHPs also reduces resource adequacy requirements compared with using ASHPs, especially in cold climate regions. More details are provided in Section 4.2.1.6 of this report.

Table ES-1. US electric power system capacity comparison in 2050

Scenario		**Total generation capacity in 2050 (GW)**	
No GHP deployment	Base	1,829	
	Grid Decarbonization	2,482	
	EFS	3,568	
			Difference
With GHP deployment	Base	1,656	173
	Grid Decarbonization	2,137	345
	EFS	3,158	410

4. **Alleviating transmission build-out requirements:** Because of the efficiency of GHPs and reduced thermal loads owing to weatherization in SFHs, less electricity generation will be needed to cool and heat buildings. Therefore, under the Base scenario, GHP deployment avoids **3.3 TW·mi**[13] transmission additions (a 17.4% reduction relative to the Base scenario without GHP), and in the Grid Decarbonization scenario, GHP deployment avoids **36.7 TW·mi** (a 33.4% reduction relative to the Grid Decarbonization scenario without GHP). Under the EFS scenario, GHP deployment avoids

[12] The total installed capacity in the EFS scenarios is much larger than in the Base and the Grid Decarbonization scenarios because of the increased demand in other sectors of the economy, including transportation and industry.
[13] Transmission deployment is measured as an increase in the capacity (terawatts) of modeled transmission lines multiplied by the length (miles) of the lines. The terawatt-mile is a common unit of measurement for transmission expansion in capacity expansion models.

65.3 TW·mi (a 37.6% reduction relative to the EFS scenario without GHP). **Assuming transmission lines have 1,500 MW capacity, a 65.3 TW·mi reduction is equivalent to 43,500 mi of transmission lines that do not need to be built—enough to cross the average contiguous US coast-to-coast distance 16 times.**

The larger reductions in the Grid Decarbonization and EFS scenarios are due to the longer transmission additions required to connect VRE resources to load centers and an increased need to flexibly move power generated with VREs over long distances. The total capital cost savings in present value in the long-distance transmission system resulting from the mass GHP deployment is $2.7 billion in the Base scenario, $29.9 billion in the Grid Decarbonization scenario, and $39.5 billion in the EFS scenario (dollar amounts in present value using a 5% discount rate). Recently, it has been more challenging to permit and construct new transmission systems; avoiding new transmission build-out through GHP deployment may have benefits beyond cost by reducing the uncertainty and delays of getting new transmission constructed to serve the needs of a decarbonized grid. More details are provided in Section 4.2.1.2 of this report.

5. **Reduced summer and winter resource adequacy requirement:**[14] Another advantage of mass GHP deployment is its impact on *capacity that can contribute toward resource adequacy*—reliable generation that is deployed in the summer and winter when demand peaks. In the Base scenario, mass deployment of GHPs means that the grid no longer needs 102 GW (summer) and 95 GW (winter) of capacity that can contribute toward resource adequacy, mostly from power plants using fossil fuels. In the Grid Decarbonization scenario, 103 GW (summer) and 101 GW (winter) of capacity that can contribute toward resource adequacy would no longer be needed. In the EFS scenario, the substitution of ASHPs with GHPs reduces the resource adequacy requirement by 127 GW in summer and 185 GW in winter.

   In the Base + GHP scenario, natural gas combustion turbines (NG-CTs) and natural gas combined cycle (NG-CC) plants are largely reduced, with the next-largest reduction being in battery storage. In the Grid Decarbonization + GHP scenario, all CO_2-emitting power plants were modeled to be retired by 2050, so the largest source of the summer capacity that can contribute toward resource adequacy reduction would come from hydrogen combustion turbines (H_2-CTs). More details are provided in Section 4.2.1.3 of this report.

[14] Capacity that can contribute toward resource adequacy differs from the installed capacity discussed previously in that it represents the portion of a generator or storage capacity that can be reliably counted on during a period of need.

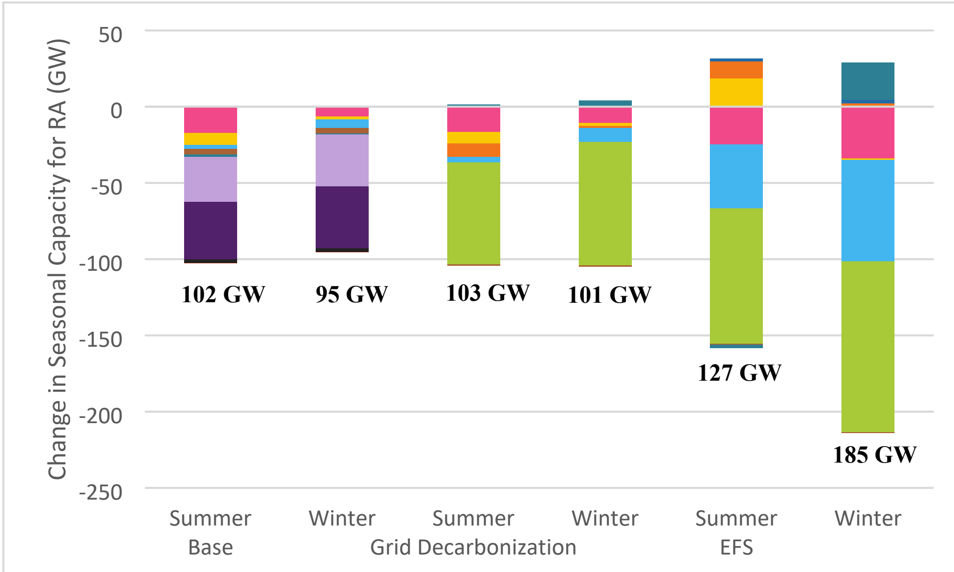


Figure ES-4. Changes in summer and winter capacity contributing to resource adequacy in 2050 for Base, Grid Decarbonization, and EFS scenarios resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes. (CSP: concentrating solar power; H2-CT: hydrogen combustion turbine; NG-CC: natural gas combined cycle; NG-CT: natural gas combustion turbine; PV: photovoltaic; PSH: pumped storage hydropower.)

6. **Reduced CO_2 emissions in the electric power system and building sector:** Compared with the Base scenario, GHP deployment will eliminate 217 MMT of CO_2 emissions each year from the US electric power system by 2050 because of the reduced total electric demand and peak load. However, in the Grid Decarbonization scenario, GHP deployment does not affect carbon emissions from the electric power system. This lack of effect is because, in the Grid Decarbonization scenario, carbon emissions reductions are built into the scenario, with the rapid 95% power system decarbonization target in 2035 and complete decarbonization in 2050. Therefore, GHP deployment rates modeled in this study do not alter the emissions from the electric power system. However, if the emissions that are avoided from the building sector through the avoided on-site fuel combustion are applied as a decarbonization credit to the grid, the net effect of GHP deployment is to achieve the emissions reduction goal of decarbonizing the grid by the year 2035. This observation is explored in greater detail in Section 4.2.1.4 of this report.

   GHP deployment could also avoid CO_2 combustion emissions related to end-use heating in the building sector. The emissions reductions in the electric power system and the building sector are counted toward the economy-wide impacts. As shown in Figure ES-5, the deployment of GHPs leads to a 7,351 MMT cumulative emissions reduction from 2022 to 2050 compared with the Base scenario, where the 3,033 MMT reduction comes from the electric sector, and 4,318 MMT comes from the building sector (a 26% reduction in building sector emissions). Compared with the EFS scenario, the mass deployment of GHPs reduces 2,178 MMT cumulative emissions from 2022 to 2050, which is from the building sector (a 16% reduction in building sector emissions).[15] More details are provided in Section 4.2.1.4 of this report.

[15] The EFS scenario had a higher share of commercial building electrification using ASHPs than the GHP retrofit scenario, contributing to the small increase in commercial building emissions.

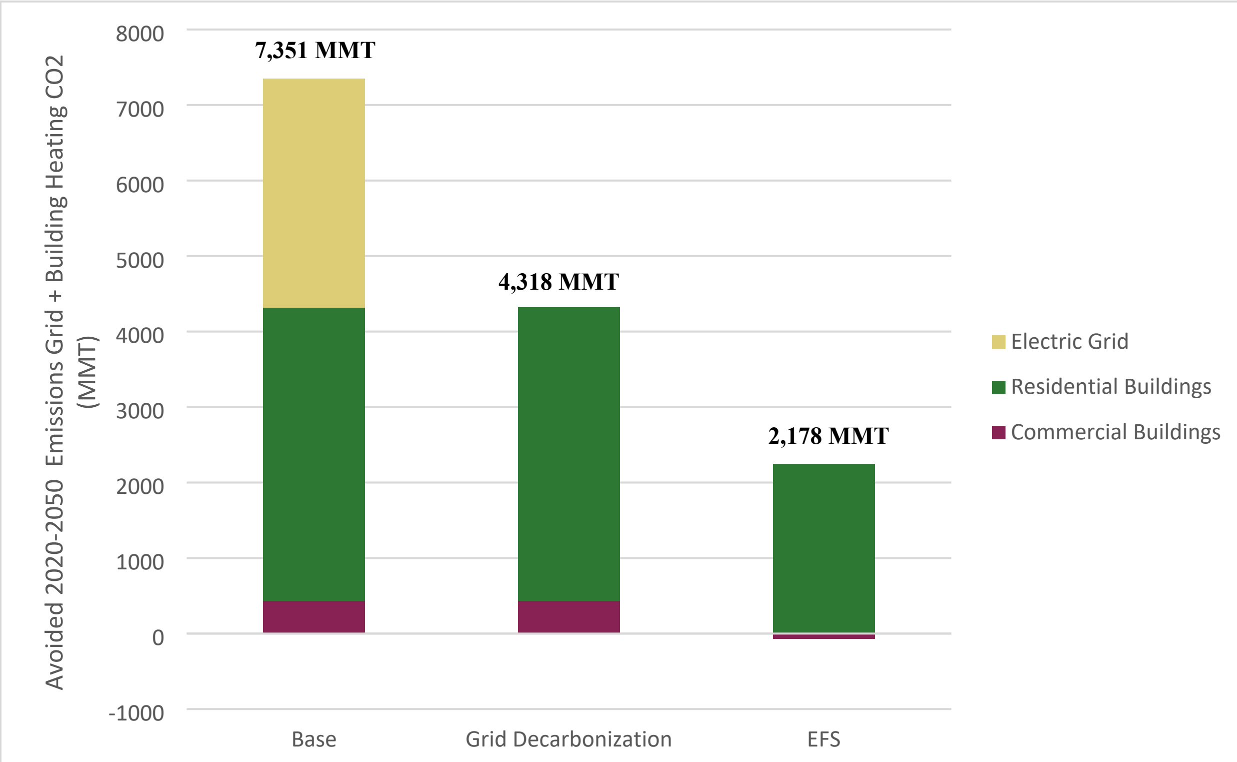


Figure ES-5. Cumulative economy-wide emissions reductions from 2022 to 2050 resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes, in the Base, Grid Decarbonization, and EFS scenarios.

7. **Reduced marginal system cost of electricity for consumers:** The marginal system cost is the wholesale cost for electricity that wholesale buyers pay to generators and grid operators. The marginal system cost ultimately affects what consumers pay to electricity providers.[16] GHP deployment reduces peak energy demand and flattens annual energy use, which lowers the marginal system cost to wholesale buyers in the Base, Grid Decarbonization, and EFS scenarios.

   As shown in Figure ES-6, the reduction in marginal system costs in the Base + GHP scenario is relatively small (6% in 2050) because many of the currently operating natural gas and coal plants have already recovered their initial investment costs. However, with GHP deployment, the increase in marginal system cost resulting from transitioning the existing grid (Base) to a decarbonized grid can be cut by nearly a third.

   GHP deployment in the Grid Decarbonization scenario reduces the new investment required to meet capacity and generation needs, yielding greater savings (a 12% reduction in 2050) in the marginal system cost than in the Base scenario. From 2022 to 2050, the reduced marginal system cost decreases wholesale electricity payments from consumers by $316 billion in the Base scenario, $557 billion in the Grid Decarbonization scenario, and $606 billion in the EFS scenario (all present values considering a 5% discount rate). More details are provided in Section 4.2.1.5 of this report.

[16] The marginal system cost comprises the locational marginal price of electricity, the marginal price of capacity for resource adequacy for the planning reserves, the marginal price of operating reserves, and the marginal credit price of renewable portfolio standards.

	Scenario	Marginal system cost in 2050 ($/MWh)		Annual payments in 2050 ($B)		Present value of cumulative electricity payments from 2022 to 2050 ($B)	
No GHP deployment	Base	49		257		3,163	
	Grid Decarbonization	83		436		4,361	
	EFS	90		636		5,460	
			Savings ($Mwh)		Savings ($B)		Savings ($B)
With GHP deployment	Base	46	3	217	39	2,848	316
	Grid Decarbonization	73	10	341	95	3,805	557
	EFS	83	7	504	132	4,854	606

Figure ES-6. Marginal system costs and payments of electricity in various scenarios.

8. **Reduced cumulative system cost of electricity:** The cumulative system cost captures the capital costs of generators and transmission systems, as well as the costs for operating the generators and the grid. As shown in Figure ES-7, GHP deployment could reduce the cumulative system cost by $147 billion (a 5.0% reduction) in the Base scenario, $246 billion (a 7.1% reduction) in the Grid Decarbonization scenario, and $306 billion (a 7.4% reduction) in the EFS scenario. The greater cost reduction in the Grid Decarbonization and EFS scenarios is mostly due to greater savings in capital costs and transmission investments compared with the changes seen in the Base scenario. More details are provided in Section 4.2.1.6 of this report.

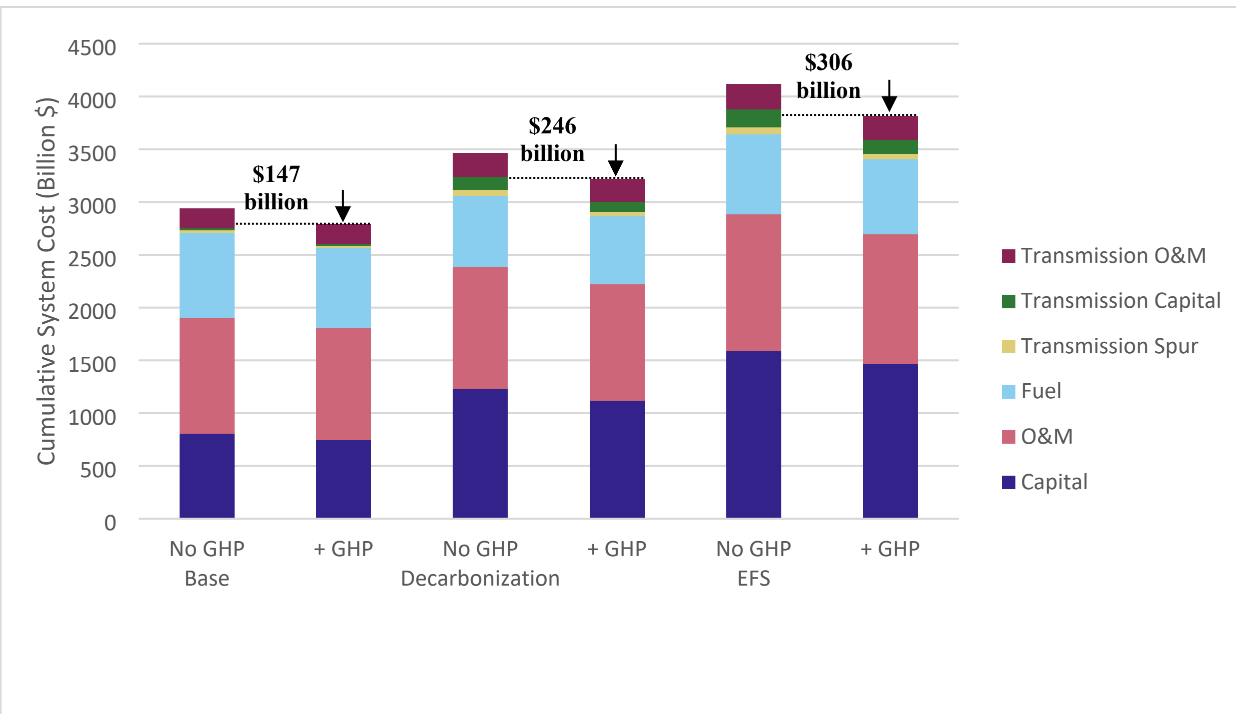


Figure ES-7. Cumulative discounted electric power system cost (present values considering a 5% discount rate) from 2022 through 2050 in various scenarios.

9. **Reduced regional peak load of electricity:** As shown in Figure ES-8, the mass GHP deployment can reduce the peak load in the summer in all reliability assessment zones (RAZs)[17] by 3%–28%. This reduction is because GHPs have a higher cooling efficiency than conventional HVAC systems. This reduction also contributes to the annual electricity consumption savings observable in Figure ES-1. The South and Southeast have higher peak load reductions than other areas because of higher cooling demand in the summer. In the winter, GHPs can also reduce the peak load for most areas; in the Southeast, where electric heating (e.g., ASHPs and electric resistance heaters) is widely used, the peak load reduction ratio can be up to 28%. Notably, the peak load is less reduced in areas where fossil fuel–based heating is used. More details are provided in Section 4.2.2.3 of this report.

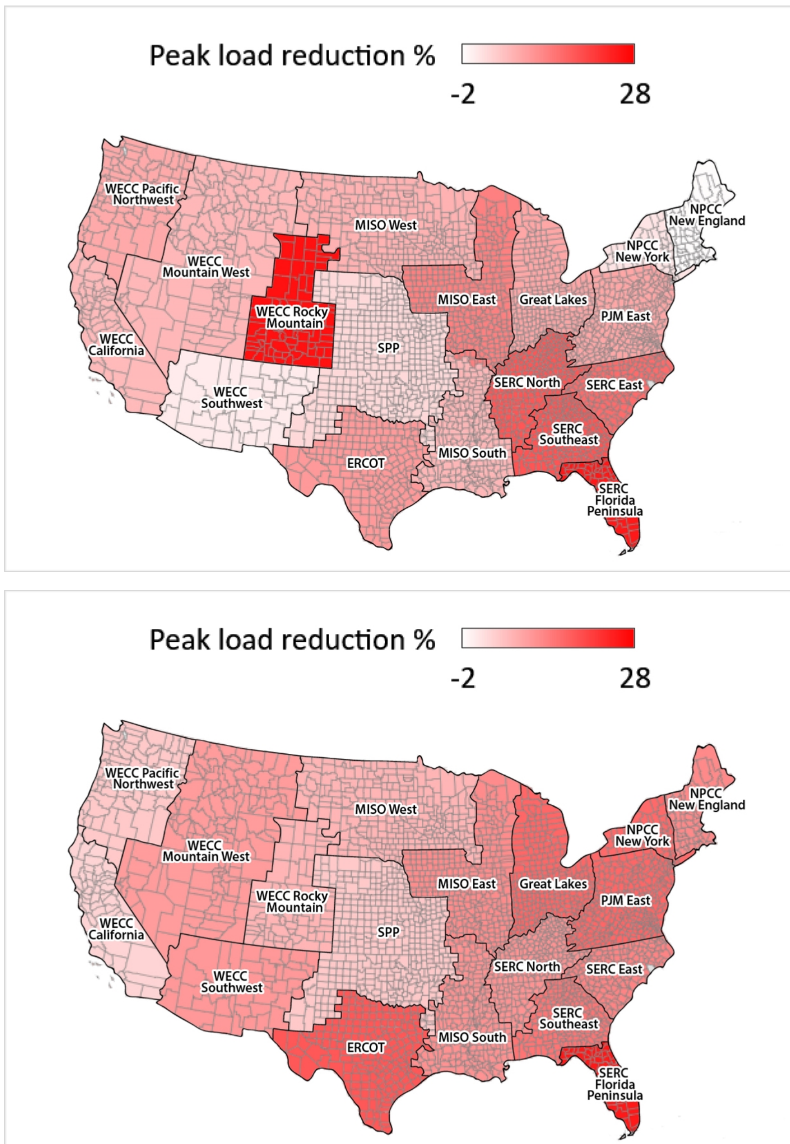


Figure ES-8. Peak load reduction ratio of the Base scenario in (top) winter and (bottom) summer resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes.

[17] The RAZs are used by the modeling program to determine regional factors beyond serving the required electric loads, such as reliability.

10. **Improved reliability of regional electric power supply:** A preliminary analysis reveals that GHP deployment can improve the operational reliability of power grids in extreme weather events. As an example, during the 2021 winter storm in Texas, approximately 28 GW (38%) of the anticipated electricity demand was left unmet during the most severe outage periods. However, if all the applicable buildings in Texas had been retrofitted with GHPs, the unserved electricity demand ratio would have been reduced to approximately 18% (10 GW). GHP deployment could thus reduce rolling blackouts, which affected many consumers and resulted in high economic losses. More details are provided in Section 5 of this report.

Study Implications

As demonstrated through this study, **the mass deployment of GHPs can electrify the building sector without overburdening the US electric power system**. In all GHP deployment scenarios considered, significant reductions are realized in the needed power generation and capacity, energy storage capacity, transmission buildouts, a seasonal capacity that can contribute toward resource adequacy, CO_2 emissions, and marginal and cumulative system costs of electricity across the United States. Although this study was for the contiguous United States only, the findings are applicable to all 50 states and US territories.

Impacts on annual electricity consumption varied geographically, with greater reductions in the southern part of the country. Meanwhile, in the northern United States, carbon emissions related to on-site heating were reduced. GHP deployment can reduce the peak load of electricity in all RAZs in the summer by 3%–28%. A similar reduction can be achieved in winter in all RAZs except in the Northeast because GHPs displace natural gas heating rather than electrified heating (e.g., ASHPs) in this region. The reduced need for electricity generation results in significant reductions in CO_2 and other emissions. This study also found that using GHPs to electrify space heating in buildings requires less electricity generation capacity than using ASHPs.

In all analyzed scenarios, deploying GHPs significantly reduces the national peak electricity demand in 2050. With the mass deployment of GHPs, less new generation capacity will be needed to meet the electricity needs of the country, reducing the required investment to expand the grid, including generators and transmission lines. Mass GHP deployment can be a key strategy to achieve decarbonization—not just for homes and communities, but for the entire grid and the broader US economy.

Moreover, the beneficial impacts of GHP deployment presented in this study may be conservative. For example, the analysis used only existing GHP technology; it did not consider GHP technology improvements over the study period. However, mass deployment of GHPs would be expected to spur in technology improvements (e.g., higher efficiency and lower cost). Because this was an impact analysis only, there is a simplifying assumption that all the GHP systems are for individual buildings. The study did not analyze the district geothermal energy networks, which have the potential for large capital expenditure reductions and improved performance. Water heating was not considered as part of this analysis but is a need that could be addressed by GHPs. The study also did not attempt to estimate domestic job creation resulting from GHP mass deployment, which is expected to be significant.

To deploy GHPs into 68% of residential and commercial buildings in the United States between 2022 and 2050, it is estimated that 5 million GHP units need to be installed each year. However, currently, only about 70,000 GHP units are installed in the US each year (Malhotra et al. 2023). This significant gap for GHP deployment needs to be addressed through technology development, supporting policies, innovative business models, and substantial investments from both the building and electric sectors.

1. INTRODUCTION

The Biden-Harris administration has set aggressive goals to reduce economy-wide emissions and achieve a 100% carbon pollution–free electric power sector by 2035 (i.e., supply-side decarbonization targets) and a net-zero emissions economy by 2050 (i.e., demand-side decarbonization targets). According to the *Annual Energy Outlook 2022* published by the US Energy Information Agency (Nalley and LaRose 2022), building heating and cooling currently represent 13% of total primary energy use, 15% of total electricity use, and 12% of total CO_2 emissions (including those from the electric power sector) in the United States. Technologies to increase building energy use efficiency and reduce emissions are critical to meeting decarbonization goals.

Electrifying space heating and water heating in buildings using electric heat pumps is a method to reduce carbon emissions. Air source heat pumps (ASHPs) are the most common type of electric heat pumps in the marketplace. ASHPs extract heat from the ambient air to warm buildings or move heat to the ambient to cool buildings. The heating and cooling capacity and efficiency of ASHPs thus depend on and are limited by the ambient air conditions. The heating capacity and efficiency of ASHPs typically drop when the ambient temperature is low, and the heating demand is high. Therefore, ASHPs are usually equipped with electric resistance heaters to provide supplemental heating, which could result in high power draws when they are turned on. Mai et al. (2018), Tarroja et al. (2018), and White and Rhodes (2019) indicated that replacing gas-fired furnaces with ASHPs in the residential sector would result in higher annual electricity consumption and a shift in electric peak demand from summer to winter in regions with cold climate. Such a change could substantially affect how the power grid operates and would require substantial new investments in the electric power infrastructure.

Geothermal heat pumps (GHPs, i.e., ground source heat pumps) are another type of electric heat pump. GHPs use the ground (or sometimes water bodies such as lakes) as their heat sink/source instead of the ambient air, and they use water or a mixture of water and antifreeze as the heat transfer medium, which can transfer heat much more effectively than the air. Because of the relatively stable temperature of the ground, GHPs are more energy-efficient than ASHPs in providing heating and cooling to buildings. GHPs have been used in residential and commercial buildings in all 50 US states (Liu et al. 2019). Previous studies (e.g., Bayer et al. 2012, Liu et al. 2017, Yuan et al. 2012, You et al. 2021) reported that GHPs are typically 20%–50% more energy-efficient than conventional heating and cooling systems. Furthermore, GHPs offer a promising path to reduce economy-wide CO_2 emissions by reducing the power needed for providing space cooling and electrifying space heating, which is currently provided in many buildings by furnaces/boilers consuming natural gas, heating oil, propane, or other fossil fuels. Lim et al. (2016) reported that retrofitting residential buildings in the United States with GHPs could lead to maximum annual savings of 1.3 EJ (1.3 quad Btu) in energy, \$7.1 billion in energy costs, and 64.8 million metric tons (MMT) in CO_2 emissions. Liu et al. (2019) reported that if all the existing HVAC systems in the residential and commercial sectors were retrofitted with GHPs, annual primary energy consumption could be reduced by 5.9 EJ (5.7 quad Btu), annual CO_2 emissions could be reduced by 356.3 MMT, and annual energy costs could be reduced by \$49.8 billion. The 5.7 quad Btu of primary energy savings from GHP retrofits could reduce the US primary energy consumption for heating and cooling by 46%. However, these studies only assessed the impacts of GHP retrofitting on buildings. The effects of large-scale GHP deployment on the electric power sector have not been examined in previous studies.

The electric power sector represents a substantial portion of the US energy system. In 2021, the electric power sector used 38.2 EJ (36.9 quad Btu), or 38%, of the total primary energy consumption and resulted in 1,559 MMT, or 32%, of CO_2 emissions in the United States. Depending on the efficiency of the electrified heating and cooling technology deployed, implications for grid decarbonization and costs could vary significantly. Therefore, when considering the effects of heating electrification via electric heat pumps, the system-level coupling of the electric power sector with the building sector must be evaluated.

Liu et al. (2015) reported that by 2012, the cumulative capacity of GHPs installed in the United States reached 3.9 million refrigeration tons (approximately equivalent to serving 1.4 million households). Approximately 1% of the 126 million existing buildings in the United States currently use GHP systems. Major barriers that prevent the adoption of GHPs are high initial costs and spatial requirements for installing ground heat exchangers (GHEs). The US Department of Energy's (DOE's) *GeoVision* analysis (2019) predicted that the "equivalent of more than 28 million households [would be] using geothermal heat pumps by 2050." These numbers were based on market potential (i.e., only including GHP systems with a simple payback of less than 10 years), whereas economic potential (i.e., including GHP systems with a life cycle cost savings over 20 years) was far higher and would equate to 60 million households.

GHP applications have no resource limitations. The thermal storage capacity of the Earth is essentially inexhaustible from the standpoint of using GHPs in every building in the United States. Therefore, the main limiting factor is the economics. Economics is only limiting when considered at the building level instead of the system level, which accounts for both the building sector and the electric power sector. Considering the potential impacts of GHPs on the electric power sector, the economic potential at the system level could be greater than that projected in the *GeoVision* analysis (2019).

A recent report from the American Council for an Energy-Efficient Economy indicated that energy efficiency measures that reduce building thermal loads for heating and cooling, including building envelope improvements and HVAC system upgrades, are likely to contribute the most to energy savings and avoided electricity system costs. These energy efficiency improvements can also help mitigate many of the challenges associated with high levels of renewable energy deployment, including critical materials mining, land acquisition, transmission siting, and long renewable energy interconnection queues. Therefore, an aggregated set of energy efficiency measures should be part of any deep decarbonization or high renewable energy pathway study (Specian and Bell-Pasht 2023).

In this study, the effects of heating and cooling electrification via GHP deployment across the contiguous US,[1] which includes weatherization in single-family homes, are comprehensively analyzed for the first time. Specifically, this study investigates the national-scale benefits that GHP deployment could provide for, including

- reducing energy consumption and the associated carbon emissions,
- shedding peak electricity demand,
- lowering grid infrastructure costs, and
- improving grid operational reliability.

To facilitate the modeling and analytical work, a workflow was developed and used to effectively manage substantial project scales and underlying complexities. In this workflow, commercial and residential building GHP retrofits were first modeled individually and then aggregated to quantify the associated impacts on each balancing area (BA) of the electric energy system. Then, these building-related impacts were considered via grid modeling to evaluate the effects of GHP retrofits on the electric power sector.

The remainder of this report is organized as follows. Section 2 introduces the methodology and data sources used to evaluate the impacts on energy consumption and carbon emissions that would result from

[1] This excludes Alaska, Hawaii, and US territories because of limited data for conducting a detailed analysis. Although this study was for the conterminous United States only, the findings are generally applicable to all 50 states and U.S. territories.

a mass deployment of GHPs in the United States. Section 3 presents the building sector analysis results, and Section 4 describes the electric power sector analysis results. Section 5 presents a preliminary regional grid reliability analysis. Finally, Section 6 provides conclusions and a discussion on future work.

2. ANALYSIS METHODOLOGY

The procedure for analyzing the effects of mass GHP deployment on the US electric grid includes two stages, as depicted in Figure 2-1. In the first stage, the impacts of GHP retrofits on the energy consumption and electricity demand of residential and commercial building stocks were quantified for each county in the United States and aggregated across the contiguous United States. In the second stage, the difference in hourly electricity use that resulted from the GHP retrofits was used as an input in the grid modeling tools to evaluate the impacts of GHP retrofits on the electric power sector.

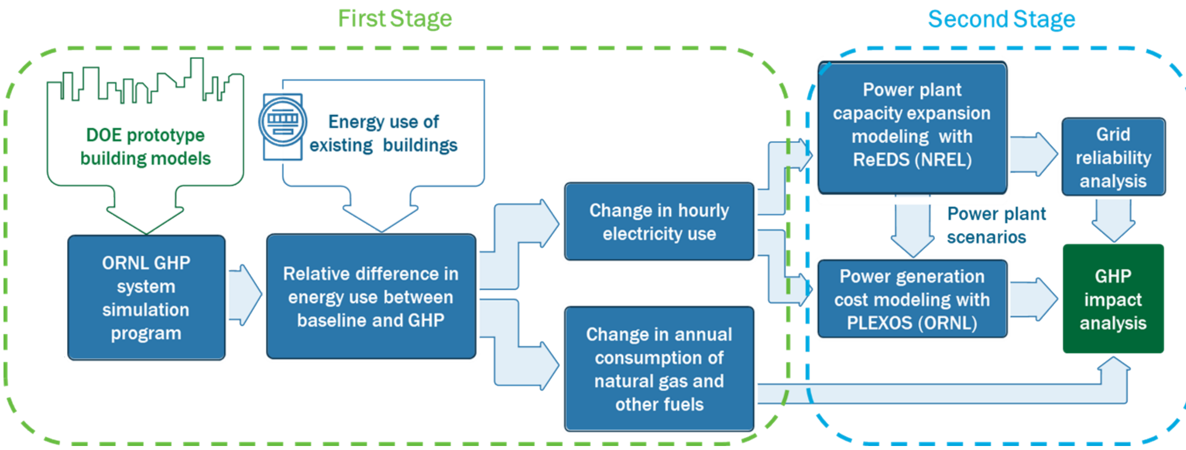


Figure 2-1. Flowchart of the combined building and grid modeling approach.

2.1 BUILDING SECTOR MODELING

2.1.1 New End-Use Load Profiles of Existing Buildings Resulting from GHP Retrofits

Existing buildings have diverse characteristics and operation schedules that must be considered when calculating their end-use load profile (EULP), which is the pattern of building energy use at each hour of the year. This study used the EULP data set published by the National Renewable Energy Laboratory (NREL; NREL 2021) for the existing US building stock in 2018[2] (does not include any new buildings after 2018) as the baseline energy use for assessing the impacts of GHP retrofits. Approximately 1 million EULPs are included in the data set, representing all major end uses (e.g., space cooling, space heating, fan, pump, lighting, equipment, water heating) in various building types and climate regions in the US commercial and residential building stocks. These EULPs are generated with sub-hourly simulations of millions of different buildings across all US counties using the ResStock and ComStock programs, which are physics-based building stock modeling tools. These models have been informed by and validated against the best-available ground-truth data (NREL 2021).

New EULPs that result from retrofitting all applicable residential and commercial buildings in the United States with new GHP systems were calculated in this study. Only HVAC-related end uses (i.e., space cooling, space heating, fan, and pump) were adjusted in the new EULPs. Air sealing (e.g.,

[2] NREL's EULP data covers 57% and 98% of the floor space of the commercial and residential buildings, respectively, that exist in 2018.

weatherstripping of windows and doors, blocking air leakage through ductwork and ceiling) was also accounted for when calculating new EULPs for single-family homes because it is a typical practice associated with GHP retrofits. Although GHPs can also contribute to water heating for part or all of the year depending on the design, using GHPs for water heating was not included in the new EULP. Figure 2-2 illustrates the following steps for calculating the new EULPs:

- Calculate energy consumption after replacing existing HVAC systems in DOE's prototype models for existing buildings (DOE 2022) with new distributed GHP systems using the GHP simulation program developed at DOE's Oak Ridge National Laboratory (ORNL) (Liu et al. 2022).

- Calculate hourly relative differences (i.e., fraction factors) in the HVAC-related site energy consumption between the existing HVAC system and the new GHP system for each prototype building in 14 US climate zones (CZs).[3]

- Identify valid candidates for GHP retrofits by using the metadata summary of the residential and commercial building stock characteristics in the original EULP data set. In this study, all buildings included in the EULP data set were considered valid for GHP retrofits except for buildings that use district heating and cooling (i.e., no energy consumption for heating and cooling at the building), mobile homes, buildings without heating or cooling, and buildings that already use GHPs.

- Apply the fraction factors to the original EULPs that are applicable candidates for GHP retrofits to determine the new EULPs that result from the GHP retrofits.

The original and new EULPs were aggregated for each BA, and the differences between the aggregated original and new EULPs were calculated to determine the changes in hourly electricity consumption and fossil fuel use in each BA. Additionally, the resulting carbon emission reductions from reduced fossil fuel consumption on the building sites in each BA were calculated using carbon emission factors of various fossil fuels (American Society of Heating, Refrigerating and Air-Conditioning Engineers [ASHRAE] 2022). The carbon emission reductions related to changes in electricity use are reported in Section 4.

[3] Based on heating and cooling degree-days, (ASHRAE 2021) defines CZs 1 through 8 as very hot, hot, warm, mixed, cool, cold, very cold, and subarctic/arctic, respectively, and sub-CZs A, B, and C as moist, dry, and marine, respectively.

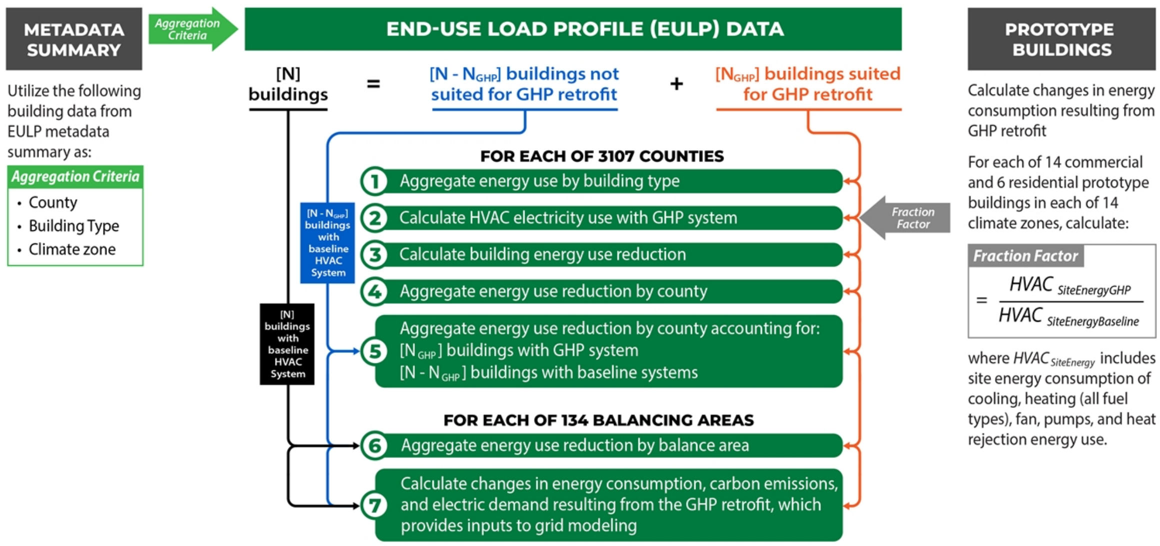


Figure 2-2. Procedures for calculating energy savings and carbon emission reductions in existing buildings resulting from GHP retrofits.

2.1.2 GHP Simulation Tool

ORNL's GHP simulation program (Liu et al. 2022) was developed to establish a fully automated process for (1) replacing an existing HVAC system submodule in a building energy simulation model with a distributed GHP system; (2) sizing each component of the GHP system, including heat pumps and vertical bore GHEs (VBGHEs); and (3) simulating the performance of the existing HVAC system and the GHP system to compare the differences. The data flow of the automated process is shown in Figure 2-3. A web interface was also developed to take user inputs and display simulation results.

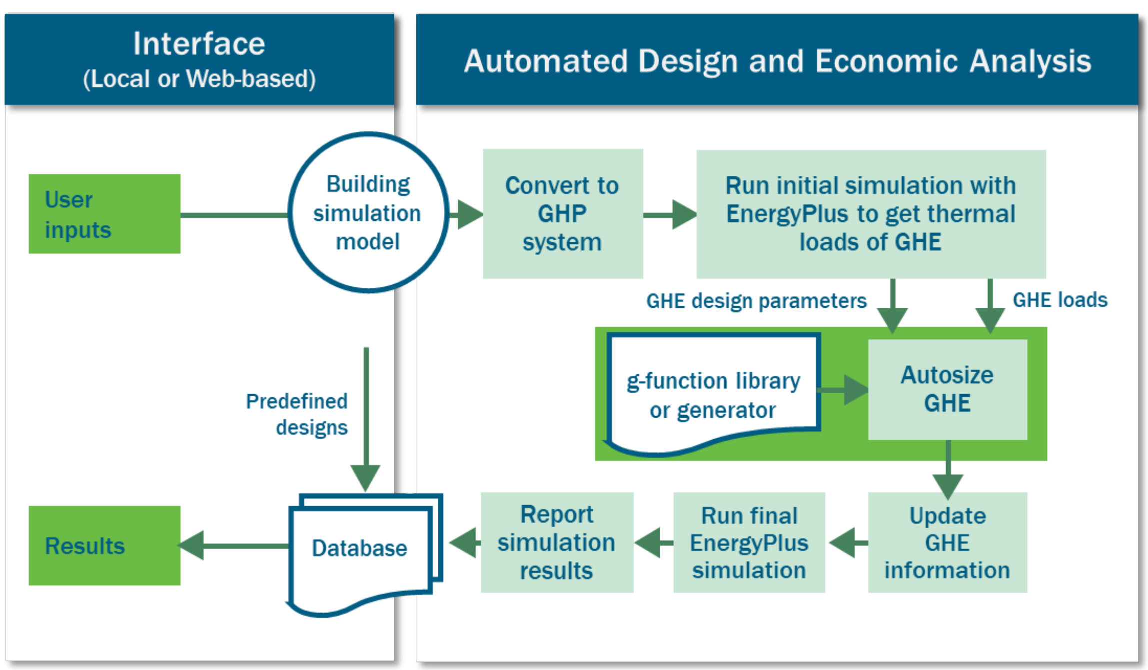


Figure 2-3. Flowchart of ORNL's GHP simulation program.

2.1.3 Prototype Building Models

DOE's prototype building models (DOE 2022) of 16 types of commercial buildings and 4 types of single-family homes (SFHs) in 14 US CZs were used in this study. Each prototype building model has a submodule for an HVAC system that is commonly used in buildings represented by the prototype model. The third edition (the latest) of typical meteorological year (TMY3) weather data (Wilcox and Marion 2008) of representative cities of these CZs were used in the energy simulation with these prototype models. To represent average existing buildings, this study used the prototype commercial building models created following the 2007 edition of ANSI/ASHRAE/IES Standard 90.1 (ASHRAE 2007) and the prototype SFH models created following the 2006 edition of the International Energy Conservation Code (IECC) (ICC 2006). Characteristics of the prototype building models used in this study and the representative cities of the 14 US CZs are listed in Appendix A.

2.2 ELECTRIC POWER SYSTEM MODELING

The electric power system in the 48 contiguous US states is divided into 134 BAs, as indicated by the boundary lines and numbered in white circles in Figure 2-4, consistent with other NREL grid modeling studies. The boundary lines generally follow the lines of real BAs but are adjusted in some instances to follow county lines instead of actual BA territory lines and to absorb small BAs into single larger regional BAs (for example, BA 10 in California encompasses several smaller BAs). Although counties are the spatial resolution of the building sector modeling, BAs are the spatial resolution at which generation, load, and transmission are balanced in the grid modeling. The map also shows the reliability assessment zones (RAZs), which are indicated with various colors on the map, to which each BA is assigned. The RAZs are used by the modeling program to determine regional factors beyond serving the required electric loads, such as reliability. The colors on the map simply indicate that each RAZ comprises multiple BAs.

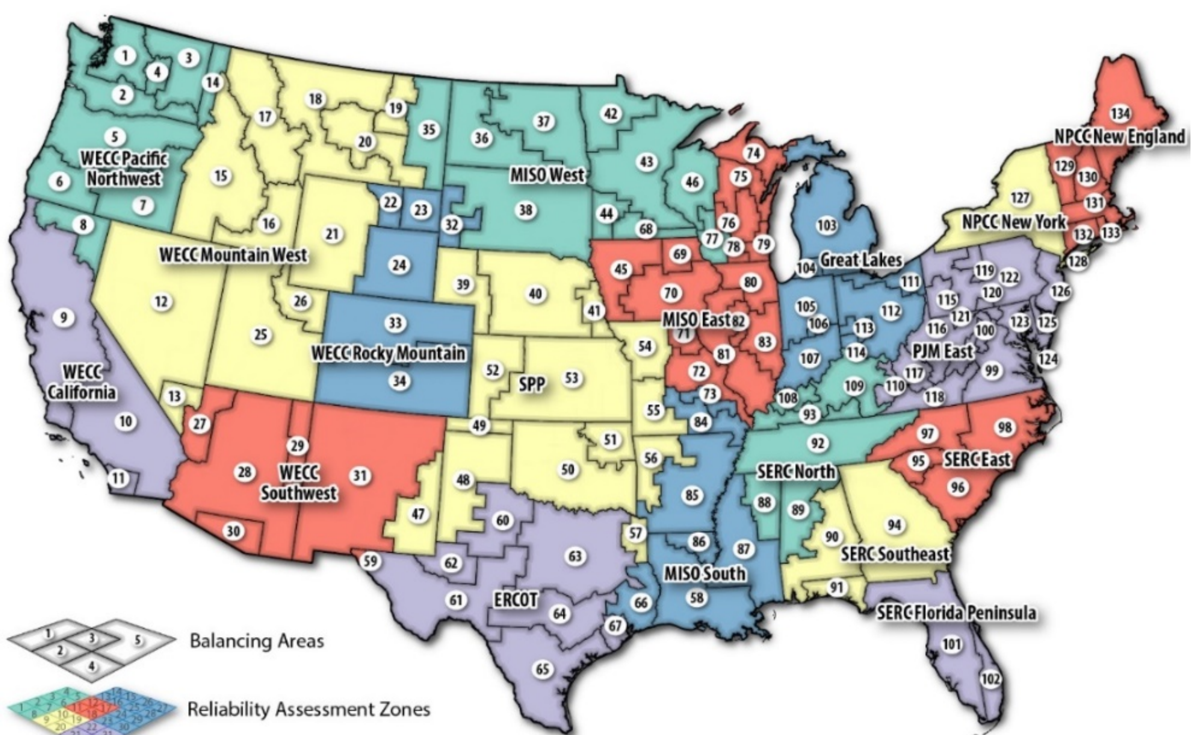


Figure 2-4. BAs of the contiguous US electric power system modeled in this study.

Two grid modeling methodologies—capacity expansion modeling (CEM) and production cost modeling (PCM)—were performed sequentially to analyze the effects of mass GHP deployment on the electric power sector. CEM is used to identify the least expensive mix of power generation in each BA over multiple decades. It takes into consideration factors such as new policies, technological advancements, changing fuel prices, and electricity demand projections. CEM is not suited to detailed, hour-by-hour simulation of power plants and grid operations. Other analyses, such as PCM, are needed alongside CEM to capture the full spectrum of the planning and operations of the electric power sector and to predict the cost and emission impacts of mass GHP deployment. PCM seeks to minimize the total cost of operating a fleet of generators to satisfy electricity demand and requirements for ancillary services. The minimization is achieved by controlling the commitment and dispatch of generators while adhering to system-level constraints on transmission capacity and generators' physical or operational limitations.

Regional Energy Deployment System Model (ReEDS), a publicly available CEM tool developed at NREL, is used to predict power system planning. It forecasts the time, location, and quantity to install new generation resources (e.g., renewable energies, fossil fuel–based units, storage systems, nuclear units) and transmission lines, accounting for the load growth and retirement of aging infrastructure in the future. The outputs of ReEDS include generation capacity, generator builds and retirements, high-level results on carbon emissions and fuel consumption, and so on.

PLEXOS, a commercial software for PCM, is used to simulate power systems' operation at hourly or finer resolution. For a given power system infrastructure, PLEXOS can optimize the operating schedule for power systems to minimize operational costs. The PLEXOS simulation outputs are in fine time resolutions, such as the online/offline status of a generator in several days, the hourly power output of a generator, and the hourly electricity prices. It can also analyze reliability indexes, such as total unserved load, power interruption, outage duration, and outage frequency.

The flowchart of the grid sector analysis is shown in Figure 2-5. The changes in hourly electricity use in the building sector of each BA resulting from the mass GHP deployment are added to the electric load profile of the BA to obtain a new BA load profile, which is used as the input of ReEDS. ReEDS simulation is performed using a representative set of time slices for multiple specific years to predict the needed generator build/retirement, generation capacity, and renewable energy penetration that are required to meet the new load profile. The time slices are composed of overnight, morning, afternoon, and evening average hours for each season, and a 17^{th} time slice selected from the 40 top summer peaking hours is included to capture higher peak operations. A translation process is employed to translate the generation, storage, and transmission network topology results from ReEDS into inputs of PLEXOS to perform the hourly modeling of grid operations and predict hourly power generation, carbon emissions, fuel consumption, and annual peak demand of the electric power sector. Thus, PLEXOS can capture more details of electric power systems' operations and associated costs compared with the 17 time slices of operations used during ReEDS optimization.

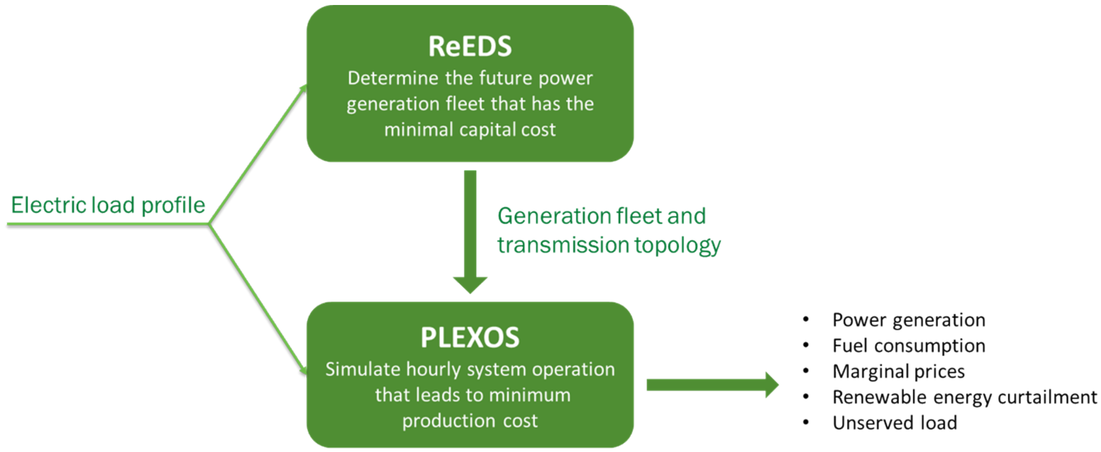


Figure 2-5. Flowchart of the electric power sector analysis.

3. BUILDING SECTOR ANALYSIS

The impacts of the mass deployment of GHP systems in commercial and residential buildings were evaluated by comparing the original EULPs of the existing building stock and the new EULPs resulting from retrofitting all buildings included in the original EULPs with GHPs, except for buildings that use district heating/cooling (i.e., no energy consumption for heating and cooling at the building), mobile homes, buildings without heating or cooling, and buildings that already use GHPs. The scenarios and assumptions used in the building modeling and the results are presented here, along with discussions of the limitations of this study.

3.1 SCENARIOS AND ASSUMPTIONS

In this study, distributed GHP systems were modeled for retrofitting existing HVAC systems in commercial and residential buildings. The distributed GHP system is typically coupled with a dedicated outdoor air system (DOAS) (Kavanaugh and Rafferty 2015), as shown in Figure 3-1. This system configuration separates outdoor air (OA) ventilation from the temperature control in each zone so that it can maintain the indoor air temperature at a user-specified set point while ensuring that only the needed OA is delivered to each zone of the building. The following assumptions were used in the simulations:

- The GHP system is sized to meet 100% heating and cooling demands in each thermal zone without using any supplemental heating or cooling.
- The heating coefficient of performance (COP) of the GHP is 4.0 and the cooling COP is 6.5 at the rating conditions specified in the ANSI/AHRI/ASHRAE/ISO Standard 13256-1 (2012). These COPs are 10%–30% higher than the minimum requirements specified by ENERGY STAR.[4] The operational efficiency of each GHP during each hour of its annual operation is modeled using the performance curves of a typical GHP, which correlate the operational heating and cooling capacity and efficiency of the GHP with the simulation-predicted supply fluid temperature of the VBGHE in response to the heating and cooling loads of the GHP.[5] The performance curves of GHPs are listed in Appendix B.

[4] https://www.energystar.gov/products/heating_cooling/heat_pumps_geothermal/key_product_criteria

[5] Some GHPs can use the condensing heat during cooling mode operation to preheat domestic hot water so that the heat rejection load to the VBGHE is reduced. However, this feature was not accounted for owing to the limitations of the simulation program used in this study.

- Each building has its own VBGHE, which comprises boreholes laid out in a square or near-square array and with uniform spacing between boreholes.[6] The design parameters of the VBGHE are listed in Table 3-1. The required number of boreholes and borehole depth of each VBGHE are autosized with ORNL's GHP simulation program (Liu et al. 2022, Spitler et al. 2022) based on the thermal loads and the VBGHE's design parameters. Each VBGHE is sized to maintain its supply fluid temperature between 1°C and 35°C year-round.[7]

- For commercial buildings, the DOAS delivers unconditioned OA to the return air of the GHP in each thermal zone. For SFHs, an energy recovery ventilator is used in the DOAS to preheat or cool the OA before it enters the building.

- Air sealing[8] is applied to SFHs as a part of GHP retrofits to reduce outdoor air ventilation to the minimum required by ASHRAE Standard 62.2 (ASHRAE 2007, 2016)[9] and to eliminate air leakage from the ductwork of the HVAC system. Air sealing can reduce the heating and cooling load, especially in cold and hot climates. Air sealing can make GHP retrofits more cost-effective because it reduces the required capacity of a GHP and the size of ground heat exchangers, which may offset the cost of air sealing and save more energy. The impact of OA infiltration and ductwork leakage on the annual heating and cooling energy consumption of SFHs at each CZ is presented in Appendix C.

- Fans used in the new GHPs are more energy-efficient than the fans used in the existing HVAC systems. Fan efficiencies and pressure rise of the existing residential HVAC system and the new GHP are listed in Appendix B.[10]

[6] We don't have information on the available land area for installing boreholes at each applicable building. We assume that, with the development of drilling technologies, such as compact drill rigs and tilted angle drilling, as well as the wide adoption of district GHP systems, there could be solutions to drill needed boreholes.

[7] Recent work has identified that in areas with mixed building types, the use of a shared VBGHE can greatly reduce the number of vertical boreholes that must be drilled (Spitler et al. 2022).

[8] Air sealing is usually done by applying weather strips at windows and walls, spraying foams in the attic, filling the cracks in the foundation and walls, and sealing the ductwork of the HVAC system.

[9] According to ASHRAE Standard 62.2 (ASHRAE 2007, 2016), the minimum OA ventilation requirement for acceptable indoor air quality in low-rise residential buildings is 0.35 air change per hour. However, the OA ventilation rate (including mechanical ventilation and infiltration) of the prototype SFH models developed based on the 2006 edition of IECC is 0.84 air change per hour, which is typical for old existing SFHs (Yamamoto et al. 2010).

[10] Most commercial HVAC systems use central air distribution systems, which typically use large, variable-speed fans to supply air throughout the building via central ductwork. These fans are quite different from the fans of GHPs, which only circulate a small amount of air within a thermal zone.

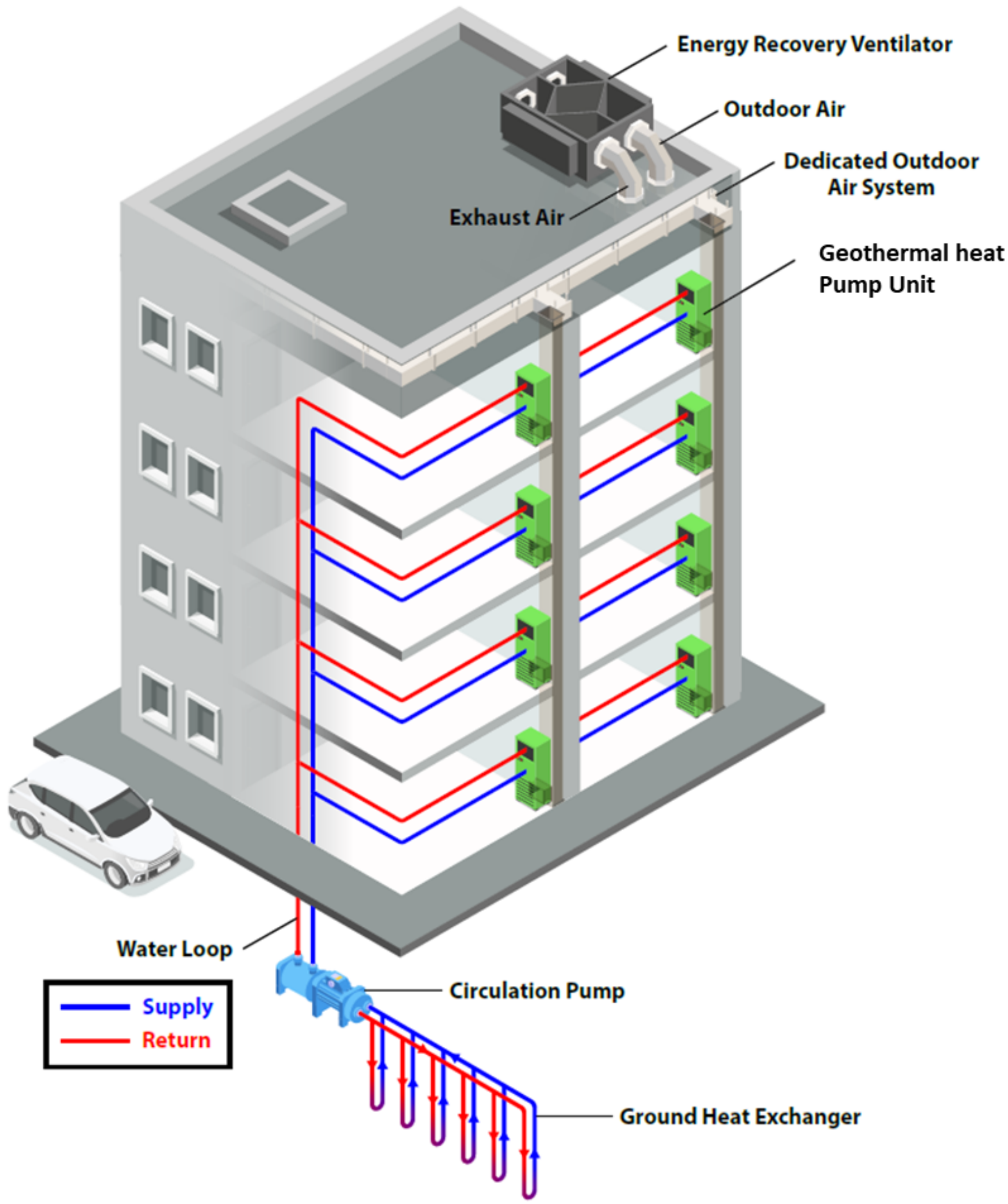


Figure 3-1. Illustration of a distributed GHP system coupled with a DOAS.

Table 3-1. Default values of VBGHE design parameters

Parameter	Default value	Parameter	Default value
Borehole radius (m)	0.0762	Grout heat capacity (kJ/[m^3·K])	3,901
U-tube pipe thickness (m)	0.002	Ground conductivity (W/[m·K])	1.29
U-tube pipe outer diameter (m)	0.027	Ground heat capacity (kJ/[m^3·K])	2,347
U-tube leg spacing (m)	0.025	Undisturbed ground temp. (°C)	Site-specific and calculated with the method by Xing et al. (2016)
Pipe conductivity (W/[m·K])	0.39	Bore spacing (m)	6.1
Pipe heat capacity (kJ/[m^3·K])	1,542	Maximum GHE supply temp. (°C)	35
Grout conductivity (W/[m·K])	1.29	Minimum GHE supply temp. (°C)	1

To represent existing commercial buildings, the DOE commercial prototype models (Pacific Northwest National Laboratory 2018) created following the 2007 edition of ANSI/ASHRAE/IES Standard 90.1 were used in this study. The 2007 edition was selected because buildings built or retrofitted around 2007 likely followed the 2007 edition of the building energy standard, and the HVAC systems in these buildings have reached their lifetime at the time of this study (2023) and need to be replaced with a new system. Similarly, the DOE residential prototype building models (Mendon et al. 2012) created following the 2006 edition of the IECC standard were used in this study to represent the existing residential buildings.[11]

3.2 HEATING ENERGY SOURCES OF EXISTING BUILDINGS

The energy sources for space heating in residential and commercial buildings were analyzed using the metadata of NREL's EULP data set. Figure 3-2 shows the percentages of total existing building floor space heated with various energy sources. This figure only shows the heating energy sources of the buildings that are considered applicable for GHP retrofits (i.e., excluding buildings with district heating and cooling, mobile homes, buildings without heating or cooling, and buildings that already use GHPs), which accounts for 78% of the total conditioned space of all existing residential buildings and 43% of the total conditioned space of all existing commercial buildings. In total, 241 billion ft^2 of floor space in the residential and commercial buildings are included in this study for GHP retrofits. As shown in Figure 3-2, although natural gas is the predominant heating energy source, a significant number of buildings are heated with electricity using electric resistance heaters or heat pumps (mostly ASHPs).

[11] Future buildings were not modeled explicitly in this study. The same energy savings percentages in the existing buildings are approximately applied to the future buildings in the grid analysis. This limitation is discussed in Section 3.4.

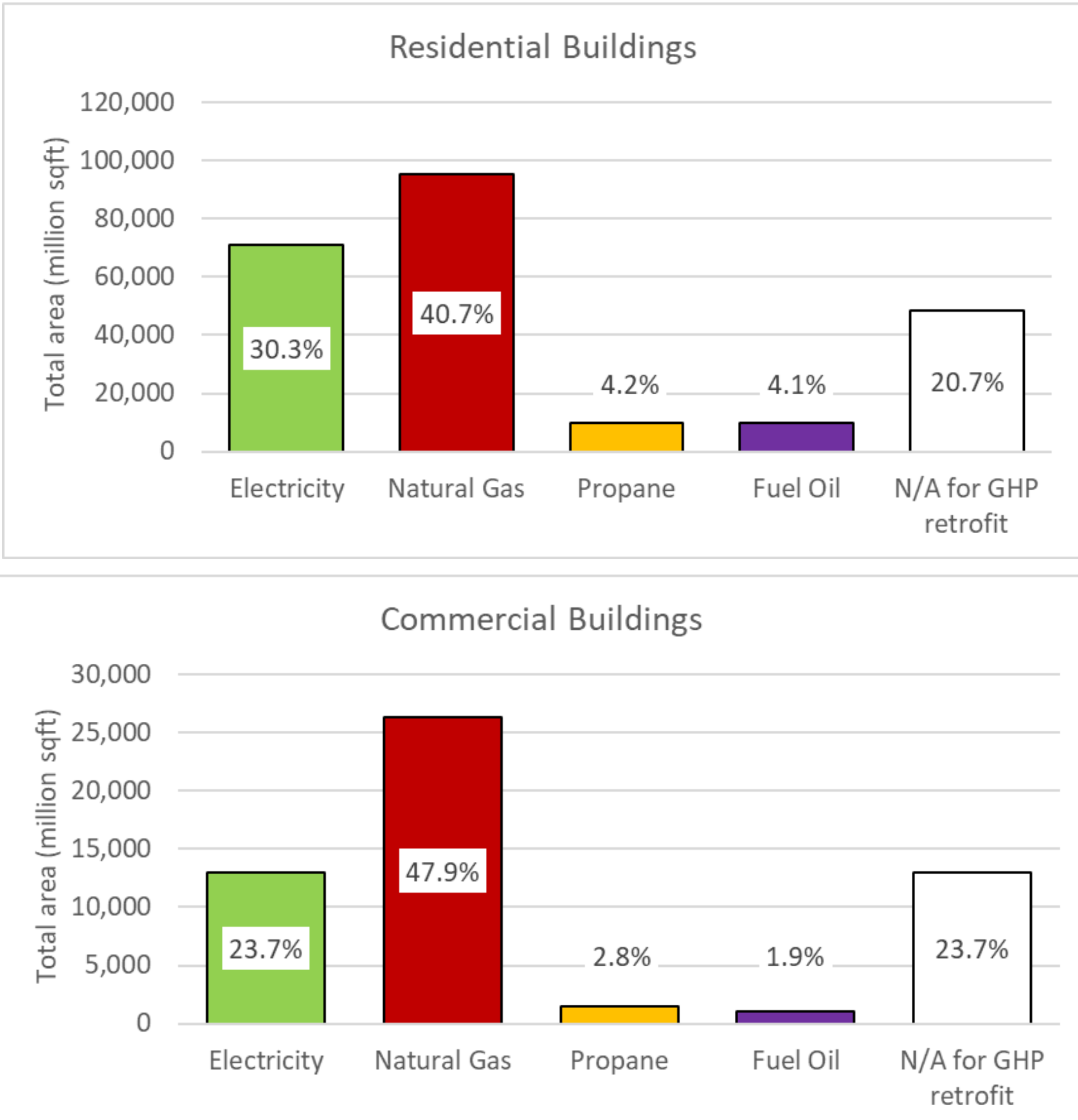


Figure 3-2. Existing residential and commercial building floor space heated by different sources. The white columns represent the amount of existing floor space that is not considered for GHP retrofits in this study.

The two stacked bar charts in Figure 3-3 show the space heating energy use in residential and commercial buildings, respectively, in each BA. Each stacked bar represents the contribution of various heating energy sources to the total space heating energy of all the buildings that are applicable for GHP retrofits in each BA. A BA map is shown in Figure 2-5. The percentages of heating energy sources vary widely across BAs. In some BAs in the Northwest region, such as BA 2 in Washington State, the share of electric heating was greater than 60%. However, the share of electric heating was less than 10% in most BAs in the Northeast region, such as BA 128 in New York state.

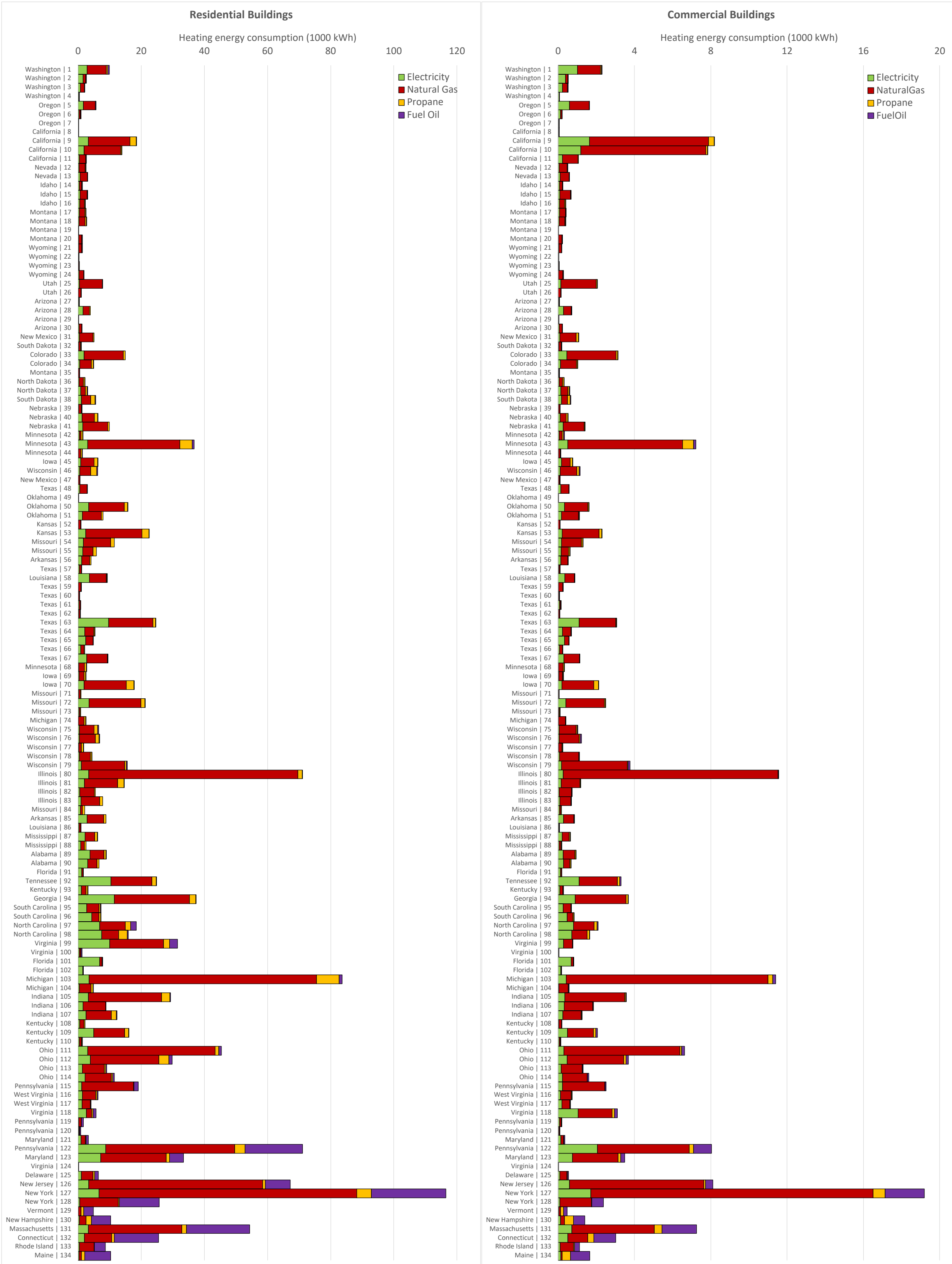


Figure 3-3. Percentages of various energy sources used for space heating in each BA for existing buildings that are applicable for GHP retrofits.

3.3 ANALYSIS RESULTS

The results of building sector analysis indicate that mass GHP retrofits (including weatherization in SFHs) have significant potential to reduce energy consumption and carbon emissions. If all applicable buildings in the contiguous United States were retrofitted with GHPs at once, electricity usage would be reduced by 401 TWh, which is an 18% reduction from the baseline EULP each year. Furthermore, 5,138 billion MJ of annual fossil fuel (e.g., natural gas, heating oil, propane) consumption (approximately 4,747 billion ft^3 of natural gas equivalent) would be eliminated. The reduced on-site fossil fuel consumption at buildings would avoid 342 MMT of equivalent carbon emissions each year. The emissions reduction resulting from the reduced electricity consumption are discussed in Section 4. The geospatial characterization of the impacts of GHP retrofits in each BA is presented here.

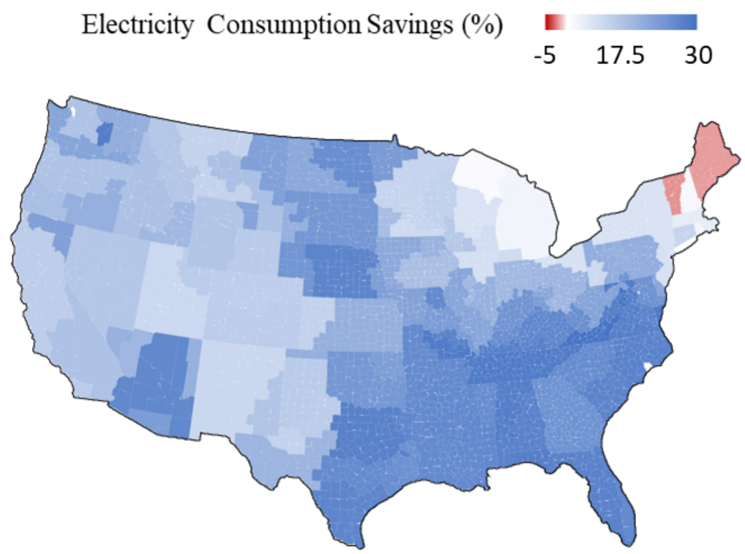
3.3.1 Geospatial Characterization of the Impacts

Because of the different heating and cooling demands in each BA and the various energy sources used for providing space heating in the existing HVAC systems, regional differences exist in the effects of GHP retrofitting. According to the US Energy Information Agency (EIA; EIA 2021), more than 99% of existing HVAC systems consume electricity to provide space cooling. GHPs reduce electricity consumption for space cooling because they are more efficient than all other commonly used existing space cooling systems. Existing space heating systems use electricity or fossil fuels. If a GHP replaces an electric heating system (e.g., electric resistance heater or ASHP), it will reduce electricity consumption for space heating. However, if it replaces fuel-burning heating equipment, it will eliminate fuel consumption and use electricity for space heating. Therefore, in southern BAs, where the cooling demand is high and more than 40% of space heating is provided with electricity, GHP retrofitting will result in significant savings in electricity. In contrast, because most space heating in northern BAs is provided by fossil fuels, the GHP retrofits will result in increased electricity consumption in the heating season, which will offset part of the electricity savings obtained during the cooling season; in limited examples (VT and ME), this offset may even slightly increase annual electricity consumption. Therefore, electricity savings gained from GHP retrofits in northern BAs are not as significant as in southern BAs. However, compared with the electricity consumption increase that would result from electrified heating with ASHPs, as demonstrated in this report and documented in previous analyses such as the *Rhode Island Strategic Electrification Study* (Erickson et al. 2020), GHP deployment (including weatherization in SFHs) achieves electrified heating with lower electricity consumption than the alternative, resulting in significant avoided costs and carbon emissions. Furthermore, the difference in energy efficiency between GHPs and conventional HVAC systems for cooling (e.g., a GHP with a cooling COP of 6.5 vs. a chiller with a cooling COP of 5.0) is smaller than that for heating (e.g., a GHP with a heating COP of 4.0 vs. a natural gas furnace with a burner efficiency of 0.8). Therefore, the site energy reduction would be higher in northern BAs, where buildings have greater heating demands.

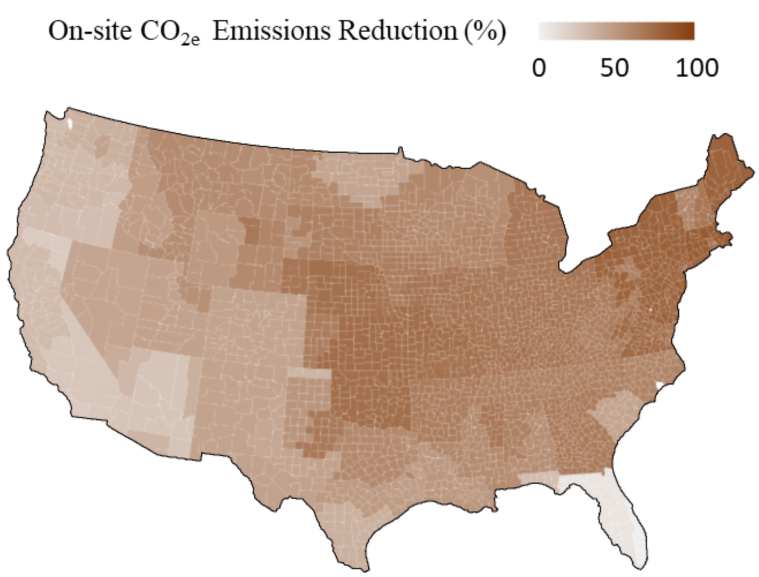
Figure 3-4 shows a geospatial representation of the percent changes in annual electricity consumption, site energy consumption, and on-site carbon emissions that result from the mass deployment of GHPs in each BA. Figure 3-4(a) shows that retrofitting the existing HVAC systems with GHPs and weatherization in SFHs will reduce electricity consumption in most parts of the United States, except in a few BAs in the Northeast. More significant reductions in annual electricity consumption will be achieved in southern BAs. On the other hand, Figure 3-4(b) shows that GHP retrofits result in higher percentages of carbon emission reductions (counted with CO_2 equivalent [CO_2e] of various emissions from combustion of fossil fuels[12]) in northern BAs (colder climates) than in southern BAs. Buildings in northern BAs have a higher burden for electrification of heat because of a higher heating load (in total energy and peak demand), so

[12] The CO_2-equivalent means the number of metric tons of CO_2 emissions with the same global warming potential as 1 metric ton of another GHG.

on average for the year, the electricity savings are not as significant and in some cases are negative. However, GHP retrofits eliminate high–CO_2 emitting, low-efficiency fossil fuel consumption for heating. Therefore, the overall site energy savings (including changes in electricity and fossil fuel consumption) on average are higher in northern BAs. Furthermore, as discussed in Section 4, to electrify all buildings' heating and cooling, the GHP retrofits investigated in this study would use less electricity compared with replacing existing HVAC systems with ASHPs.



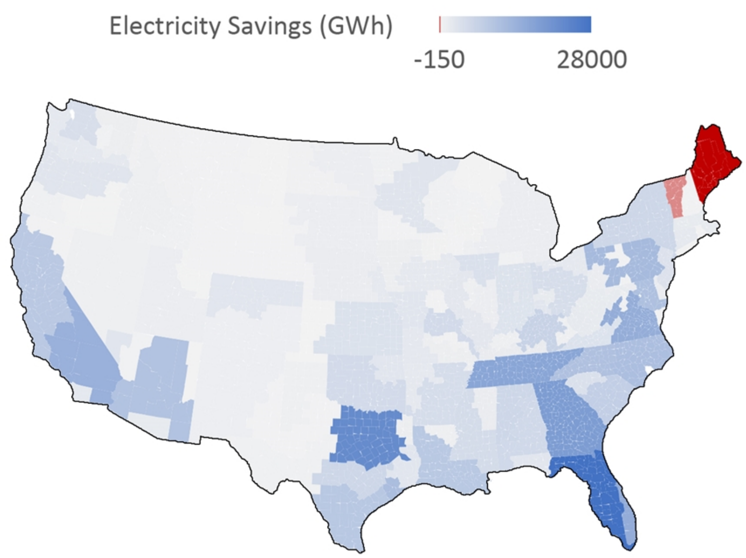
(a)



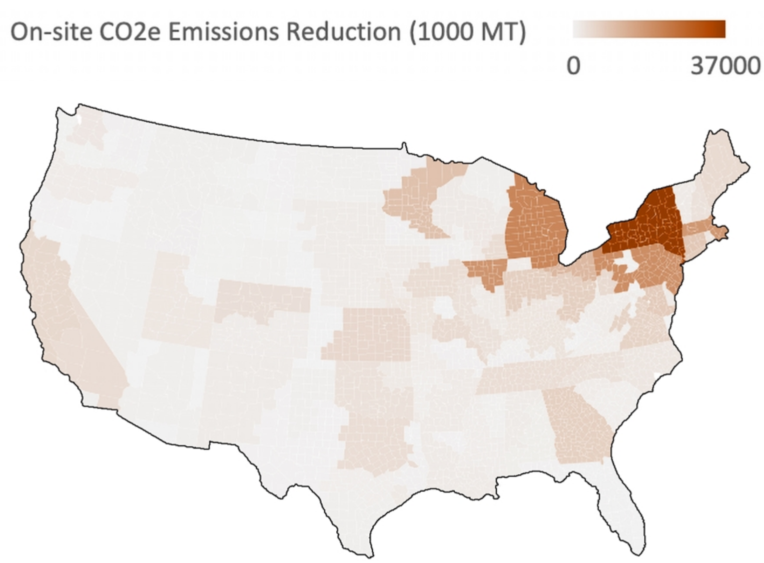
(b)

Figure 3-4. Geospatial representation of the percent changes in (a) building annual electricity consumption and (b) annual on-site carbon emissions (from combustion of fossil fuels for space heating) that would result from retrofitting all appliable existing buildings in 2018 with GHPs (including weatherization in SFHs) in each BA.

Figure 3-5 shows the absolute values of the changes in annual electricity consumption and on-site carbon emissions that would result from the mass deployment of GHPs in each BA. The absolute values of electricity savings are high in the densely populated areas in the southern and western United States, including Florida, Texas, and California. In Figure 3-5, BAs in Maine and Vermont are colored red, indicating an increase in electricity consumption. The increase is caused by the current low percentages of electric heating and low cooling demands in the existing buildings in these BAs. In terms of on-site carbon emissions reduction and site energy savings, BAs in New York and Michigan show the highest values because of the high populations and heating demands in these areas.



(a)



(b)

Figure 3-5. Geospatial representation of the absolute values of changes in (a) annual electricity consumption and (b) annual on-site carbon emissions (from combustion of fossil fuels for space heating) that would result from retrofitting all appliable existing buildings in 2018 with GHPs (including weatherization in SFHs) in each BA.

3.3.2 GHP Impacts in Each BA

Table 3-2 lists the minimum, maximum, and average values of the changes (the absolute values and the percentages) in electricity and fossil fuel consumption, as well as the on-site carbon emissions that result from the GHP retrofits in the 134 BAs. These values represent the maximum energy savings that can be achieved each year compared with the baseline energy consumption of the existing US building stock in 2018, assuming all the applicable existing buildings are retrofitted with GHPs at once. Positive values indicate energy savings or carbon emission reductions compared with the baseline, and negative values indicate increased energy use or carbon emissions.

Table 3-2. Statistics of changes in building energy consumption and on-site emissions resulting from retrofitting all applicable existing buildings in 2018 with GHPs and weatherization in SFHs in each BA

Building energy consumption parameters		Minimum	Maximum	Mean
Building electricity savings	GWh/year	−150.2	27,958	2,992
	%	−2.1	29	17
Natural gas savings	10^6 MMBtu/year	0.02	384	29
	%	1.4	77	62
Heating oil savings	10^6 gal/year	0	758	31
	%	0	100	54
Propane savings	10^6 gal/year	0.15	274	29
	%	1.6	85	56
On-site carbon emissions reduction	10^3 MT/year	16.18	36,560	2,549
	%	1.4	82	57

On-site fossil fuel consumption and associated carbon emissions are reduced in all BAs. Although GHP retrofits result in electricity savings in most BAs, they lead to increased electricity consumption in a few BAs in the Northeast because most space heating in these BAs is provided by furnaces or boilers that consume fossil fuels, and the heating requirements are very large. Replacing these furnaces and boilers with GHPs will increase electricity consumption but will eliminate fossil fuel consumption for space heating. More electricity would be consumed in these BAs if the gas furnaces were replaced with ASHPs because of their lower heating efficiency than GHPs and the usage of supplemental electric resistance heating. In BAs without propane or heating oil consumption, the change in propane or heating oil consumption is zero.

All the graphs and tables in this section come from modeling the changes if all applicable existing buildings in 2018 were retrofitted at once. However, retrofitting all the applicable existing buildings will take many years, so the energy savings and carbon emission reductions that can be achieved each year would be smaller than those presented above.

If GHP deployment increases linearly from 0% in 2021 until reaching its maximum by 2050,[13] cumulatively, $1,020 billion[14] in fuel costs will be saved, and 5,290 MMT equivalent carbon emissions will be avoided by replacing the on-site consumption of fossil fuels for space heating with GHPs and weatherization in SFHs. These numbers are strictly the on-site cost savings and carbon emission reductions that are achieved in the building sector and do not include the fuel cost savings and emission reductions in the electric power sector, which is assessed in Section 4.

[13] This calculation does not account for any new construction between 2021 and 2050.
[14] The cumulative fuel cost is calculated based on AEO-projected fuel prices (USD [2021]) at various regions in the United States. Data source: EIA. 2022. "Table 3. Energy Prices by Sector and Source, Reference Case." *Annual Energy Outlook 2022*, Interactive Table Viewer. https://www.eia.gov/outlooks/aeo/data/browser/.

3.4 DISCUSSION AND LIMITATIONS OF THE CURRENT STUDY

Energy savings from the GHP retrofits result from several causes. First, the higher operational efficiency of the new GHP system is a result of more favorable ground source temperatures than ambient air for the heating and cooling operation of the heat pump. Second, distributed GHP systems modeled in this study avoid the common issue of simultaneous heating and cooling in commercial buildings conditioned with conventional variable air volume systems. Third, fan power is reduced by using fans with higher efficiency and separately controlling the airflow for climate control and OA ventilation (i.e., using a small fan in the DOAS to deliver OA and allowing fans of the GHPs to be turned on and off with the compressor based on the thermal demands). Finally, heating and cooling loads are lowered by reducing air infiltration and ductwork leakage in SFHs.

The limitations in the building energy simulation performed in this study are as follows.

- The prototype building models are based on the 2007 edition of ANSI/ASHRAE/IES Standard 90.1 for commercial buildings and the 2006 edition of IECC for residential buildings. These models are used to represent the average performance of existing buildings.[15] Newer/remodeled buildings may be more efficient, so the energy savings from retrofitting newer buildings may be lower than those calculated in this study. On the other hand, more energy savings may be obtained by retrofitting older buildings. More extensive modeling that accounts for the variances in building energy efficiency is recommended for future studies.

- Newer/remodeled SFHs may have a lower OA infiltration rate than that in the 2006 prototype SFHs, and the energy savings resulting from weatherization may be lower than what is calculated in this study. On the other hand, the energy savings may be higher by weatherizing older (leakier) buildings. More extensive modeling that accounts for the variances in air tightness in SFHs is recommended for future studies.

- TMY3 weather data were used instead of historical weather data in all the simulations of the prototype buildings and the building stock modeling used for generating the original EULPs. The typical weather year represents average weather over the past 30 years, which might not include extreme weather conditions. Therefore, the calculated peak electricity demands in this study are likely lower than in actual years in the future given the continuous climate change. It is thus recommended to consider future year weather data in future studies.

- Fraction factors for HVAC-related site energy consumption resulting from GHP retrofits and weatherization in SFHs were generated using DOE's prototype building models, which have a set of operation schedules for each prototype building. These schedules do not always align with the operation schedule of the building stock models used for generating the original EULPs, which used a series of different operation schedules for each type of the modeled buildings to reflect the diversity of building operation. It may introduce some errors in the calculated energy savings, especially during the shoulder seasons. More extensive modeling that accounts for the variances in operation schedules of different buildings is recommended for future studies.

[15] Less than 17% of existing buildings in 2018 were built after 2007, which are likely more energy efficient than the modeled buildings. On the other hand, many existing buildings built before 2007 may be less efficient than the modeled buildings.

3.5 SUMMARY

The building sector analysis results indicate that retrofitting all applicable buildings existing in 2018 with GHPs and weatherization in SFHs can save 401 TWh of electricity and eliminate 5,138 billion MJ of fossil fuel (e.g., natural gas, heating oil, propane) consumption (approximately 4,747 billion ft^3 of natural gas equivalent) each year compared with the electricity and fuel consumption of the existing building stock in 2018. The reduced on-site fossil fuel consumption at these buildings would avoid 342 MMT of equivalent carbon emissions each year. These benefits result from higher operational efficiency of GHP systems, avoided simultaneous heating and cooling in commercial buildings, reduced fan power due to improved fan efficiency and ventilation control, as well as lowered thermal loads by reducing air infiltration and ductwork leakage in SFHs.

Retrofitting existing HVAC systems with new GHPs and weatherization in SFHs will reduce electricity consumption in most parts of the United States, except in a few regions in the Northeast. Electricity savings are larger in densely populated areas in the southern and western United States. If the retrofits increase linearly from 0% in 2021 to 100% of all applicable buildings in 2050, $1,020 billion in fuel costs will be saved, and 5,290 MMT equivalent carbon emissions will be avoided by replacing the on-site consumptions of fossil fuels for space heating with GHPs and reducing air infiltration and ductwork leakage in SFHs. This estimate does not include the carbon and cost savings realized at the grid level, which are explored in the following sections.

4. ELECTRIC POWER SECTOR ANALYSIS

This section reviews ReEDS and PLEXOS modeling results to analyze the impacts of mass GHP deployment, which includes weatherization in SFHs, on the energy and capacity mix of the contiguous US electric power system. These results also show how the timing and quantity of electric power demand reduction reduces (1) the required transmission expansion for supporting grid decarbonization, (2) costs to the power system as a whole and electricity prices to consumers, and (3) the summer and winter resource adequacy requirement.

This study focuses on identifying the types and magnitudes of benefits resulting from the mass GHP deployment and weatherization in SFHs. The costs of GHP installation and weatherization, which depend on the maturity and size of the industry supporting it, were not considered as part of this study and will be accounted for in a future analysis.

This section first presents the four core scenarios and two sensitivities incorporated into the modeling analysis (Section 4.1) and then discusses the ReEDS and PLEXOS results (Section 4.2), limitations of the study (Section 4.3), and a summary of results (Section 4.4).

4.1 SCENARIOS AND ASSUMPTIONS

4.1.1 Core Scenarios

Four core scenarios were formulated for this study:

- **Base:** In this scenario, there is no GHP deployment, building sector energy consumption is consistent with Annual Energy Outlook (AEO) 2022 projections, and the CO_2 emission policy remains the same as existing state policies, including renewable portfolio standards, clean energy standards, and CO_2 emissions policies.

- **Base + GHP:** In this scenario, the GHP deployment rate increases linearly from 0% in 2021 to 100% in 2050. GHPs are included in new constructions starting in 2022, with the same assumptions as the existing buildings regarding the percentage of buildings applicable for GHPs and the energy savings compared with conventional HVAC systems.[16] The total floor space of new constructions is based on residential and commercial building stock changes[17] predicted by the EIA (AEO 2022).

- **Grid Decarbonization:** In this scenario, the national electric power grid's CO_2 emissions will be reduced by 95% in 2035 and 100% in 2050 as compared with the 2005 level.[18] This reduction indicates that all power generation will use clean energy by 2050.

- **Grid Decarbonization + GHP:** This scenario incorporates the effects of GHP deployment into the decarbonization scenario using the same GHP assumptions as the Base + GHP scenario. Both the grid decarbonization goal and the GHP deployment goal will be achieved in 2050. Avoided end-use emissions from GHP deployment do not count toward the grid decarbonization goal but are accounted for separately in the quantification of economy-wide emission effects.

4.1.2 Electrification Scenarios

In addition to the core scenarios, two electrification scenarios are formulated in this study based on values derived from the *Electrification Futures Study* (EFS, Sun et al. 2020). Both electrification scenarios use the power system decarbonization pathways used by the decarbonization scenarios among the core scenarios.

- **EFS:** No GHP deployment occurs, and economy-wide electrification of end uses—including partial building electrification through air source heat pumps (ASHPs), including the cold climate heat pumps, and other electrified devices for water heating and cooking—occurs, consistent with the values used in the high-electrification scenario from the EFS.[19] Weatherization in SFHs was not included in EFS.

- **EFS + GHP:** An economy-wide electrification of end uses occurs, along with 100% GHP deployment in applicable existing and new buildings coupled with weatherization in SFHs.[20] Electrification of other end uses (not for heating and cooling) is consistent with the values used in the high-electrification scenario from the EFS.

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[16] Energy savings in new constructions are approximately calculated by multiplying the total floor space of applicable new constructions and the normalized energy savings per unit of floor space, which are calculated based on energy savings achieved by GHPs (including weatherization in SFHs) in existing buildings as presented in Section 3.
[17] Building stock changes are modeled using the residential and commercial demand modules of the National Energy Modeling System, with residential building stock measuring the total number of units and commercial building stock measured in terms of total floor space, each broken down into US census regions.
[18] The electric sector CO_2 emission cap is based on the Decarbonization scenario in the Solar Futures Study and is consistent with goals presented in *The Long-Term Strategy of the United States: Pathways to Net-Zero Greenhouse Gas Emissions by 2050* (White House 2021).
[19] In the EFS scenario, ASHPs were assumed to be used in 68% of residential buildings and 46% of commercial space in the United States. It is also assumed that residential ASHP efficiency will increase by 116% from 2015 to 2050 in the rapid technology development case.
[20] ASHPs in the EFS scenario are replaced with GHPs.

4.2 ANALYSIS RESULTS

4.2.1 ReEDS Capacity Expansion Modeling Scenario Results

As discussed in Section 2, ReEDS is an open-source capacity expansion modeling tool developed by NREL.[21] It simulates the evolution of the US power system by providing forecasts of new generation resources and transmission lines, as well as accounting for the load growth and retirement of aging infrastructure. This subsection describes ReEDS results of generation portfolios that capture the benefits of deploying GHPs (including weatherization in SFHs) in residential and commercial buildings. The impacts with and without fully decarbonizing the grid are compared. The analysis was completed using a version of the main ReEDS model from the spring of 2022.

4.2.1.1 Generation and Capacity Portfolios

Figure 4-1 shows that in 2050, if there is complete GHP deployment for all applicable residential and commercial buildings—representing 68% of the building stock in 2050—the electric power generation requirement will be reduced by 585 TWh and 593 TWh each year compared with the Base and the Grid Decarbonization scenarios, respectively. The major difference between the Base and the Grid Decarbonization scenarios lies in the types of generation being reduced. In the Base + GHP scenario, energy generation is reduced across all technology types, including fossil and renewable technologies. In contrast, the Grid Decarbonization + GHP scenario shows reductions primarily in variable renewable generation using wind, solar, or other variable renewable energy (VRE) and hydrogen combustion turbines (H_2-CTs), with small increases in output from nuclear power plants and solar photovoltaic (PV) battery hybrid storage plants.

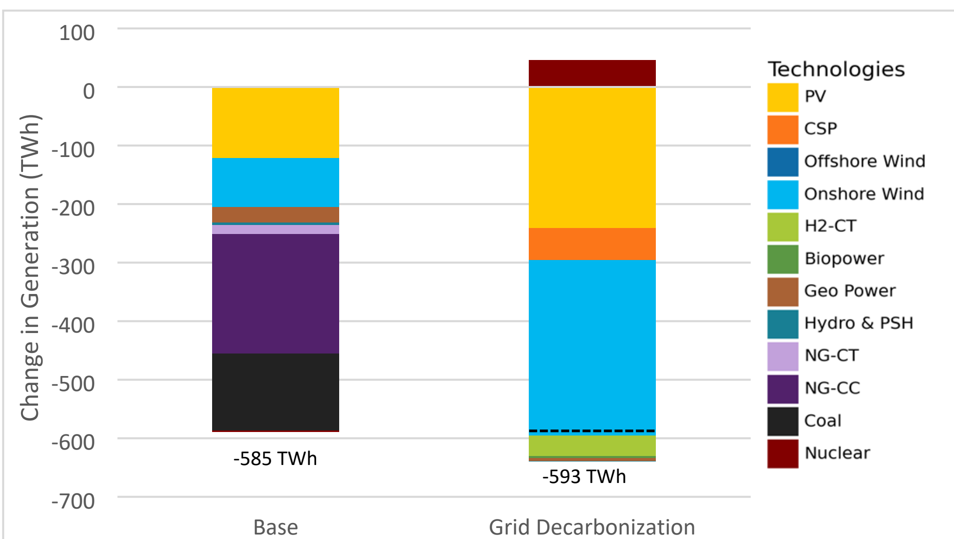


Figure 4-1. Changes in annual national generation (TWh) in 2050 resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes, in the Base and Grid Decarbonization scenarios.

Figure 4-2 shows that with GHP deployment in all applicable commercial and residential buildings, a sizeable reduction exists in installed capacity in 2050 compared with the Base and the Grid Decarbonization scenarios. GHP deployment in the Grid Decarbonization scenario doubles the reduction in installed generation and storage capacity compared with that in the Base + GHP scenario (345 GW vs.

[21] For more information, see https://www.nrel.gov/analysis/reeds/.

173 GW). In the Grid Decarbonization scenario, a large fraction (74%–77%) of the generation mix is made up of VRE sources, which typically have lower capacity factors than natural gas which is heavily used in the Base scenario. Therefore, the Grid Decarbonization scenario contains a large fraction of battery storage. These results indicate that GHP deployment will have a greater effect on electric power systems with higher VRE and energy storage deployment.

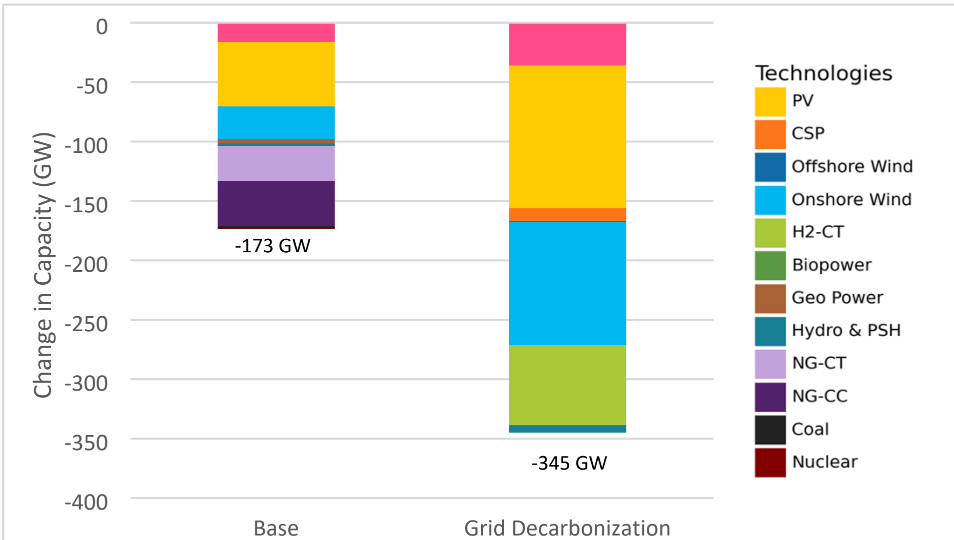


Figure 4-2. Changes in national installed capacity in 2050 (GW) resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes, in the Base and Grid Decarbonization scenarios.

4.2.1.2 Interregional Transmission Expansion Requirement

The interregional transmission expansion results are shown in Figure 4-3. The mass GHP deployment in the Base and the Grid Decarbonization scenarios reduces the need for transmission additions. Similar to the generation capacity changes, a greater benefit of avoided transmission additions can be achieved by deploying GHPs in the Grid Decarbonization scenario than in the Base scenario. In the Grid Decarbonization scenario, the electric power system transitions to a high-VRE system, which benefits from increased transmission additions to connect load centers and to provide geographic diversity of generation and load. The mass GHP deployment can reduce the new transmission requirement by 3.3 TW·mi, or a 17.4% reduction, in the Base scenario and 36.7 TW·mi, or 33.4% reduction, in the Grid Decarbonization scenario. With a representative transmission expansion of 1,500 MW capacity per transmission line, the 36.7 TW·mi reduction could represent on the order of 24,500 mi of avoided transmission construction.

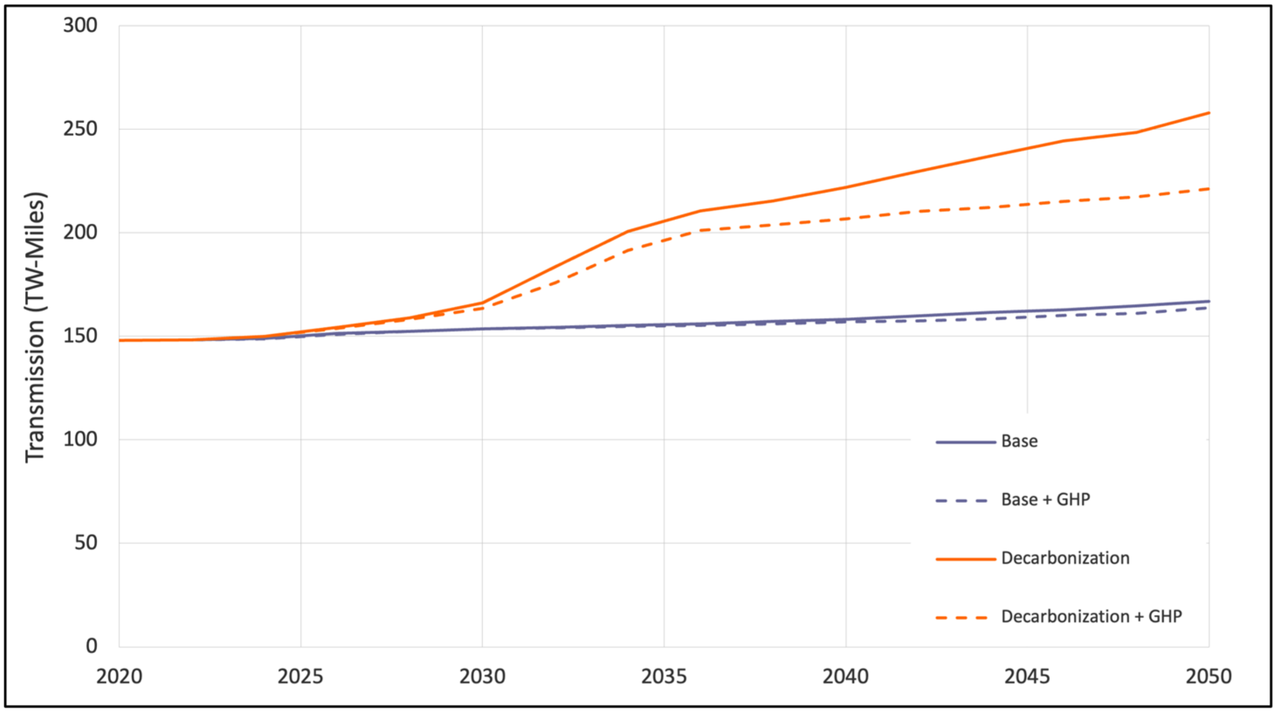


Figure 4-3. Interregional transmission expansion requirements in the Base and Grid Decarbonization scenarios with and without deploying GHPs into residential and commercial buildings in the United States (including weatherization in single-family homes) from 2022 to 2050.

Table 4-1. Interregional transmission expansion results comparison

Scenario		New + existing transmission in 2050 (TW·mi)	New transmission in 2050 (TW·mi)	Reduction (TW·mi)	Reduction (%)	Present value of transmission capital cost savings from 2022 to 2050 ($ billions)
Base	No GHP	167.0	19.0	—	—	—
	With GHP	163.7	15.7	3.3	17.4	2.7
Grid Decarbonization	No GHP	257.9	109.9	—	—	—
	With GHP	221.2	73.2	36.7	33.4	29.9

Reduced transmission has two effects: cost savings and ease of implementation. The total system cost savings in terms of the present value (5% discount rate) in the long-distance transmission system from the deployment of GHPs is $2.7 billion in the Base scenario and $29.9 billion in the Grid Decarbonization scenario. Transmission costs, including capital and operation and maintenance (O&M), account for 10% of total grid costs. Although GHP deployment reduces the requirement for new transmission construction and the associated costs, the transmission cost savings represent only approximately 1% of the total electricity payment reduction between 2022 and 2050. In recent years, there has been greater difficulty in permitting and constructing new transmissions. Therefore, reducing the amount of high-voltage transmissions may have benefits beyond cost savings by reducing the uncertainty and delays of getting new transmissions constructed to serve the needs of a decarbonized grid. It also reduces land use impacted by the transmission expansion.

4.2.1.3 Resource Adequacy

Resource adequacy (RA) is an important criterion for planning and operating electric power systems. Sufficient RA is required to meet the supply- and demand-side electric demands without a shortfall. Consumption and generation must be precisely balanced at all times; shortfalls in energy can result in blackouts. North American Electric Reliability Corporation (NERC) guidance sets a standard that power systems should procure sufficient eligible capacity such that there should be less than 1 day of shortfall in 10 years. The capacity that contributes to RA differs from the installed capacity discussed in the previous subsection in that it represents the portion of a generator or storage resources capacity that can be used during a reliability event. The amount of capacity that can contribute toward RA varies depending on the type of supply and the timing of reliability events. Although most regions currently experience peak and net peak demands in the summer, electrification (especially in buildings) can create more winter-peaking regions. The 100% Clean Electricity by 2035 Study (Denholm et al. 2022) contained electrification scenarios assuming completely electrified residential and commercial space heating without using GHPs (assumed electrification with ASHPs supplemented with electric resistance heaters) and observed winter peaks 35% higher than summer peaks. This transition from summer peak to winter peak is not included in the Base and Grid Decarbonization scenarios (with and without GHPs), but it is partially modeled in this study's EFS scenario (see Section 4.2.1.7).

ReEDS models RA and ensures that planning reserve margins comply with published NERC values for the peak demand and available capacity that can contribute toward RA in each season. Technologies are assigned a capacity credit, which represents the availability of a technology to produce power during a reliability event. For example, conventional nonvariable generation resources have a capacity credit of one. For VRE, a seasonal capacity credit is calculated by using the net hourly load duration curve to approximate the expected load-carrying capacity. This method captures the variability in weather, as well as the geographic correlation in resources that affect a VRE's ability to contribute capacity toward RA. Storage capacity credit is calculated by simulating hourly storage dispatch for each region and storage configuration. Further details on the calculation of capacity credit are available in ReEDS documentation (Ho et al. 2021). In the modeled core scenarios, only the summer season was a binding requirement for RA, and the other seasons' resources were in excess of the established planning reserve margin. This section focuses on changes occurring during the summer season because it is the driving factor in system investment decisions.

Figure 4-4 demonstrates the annual difference in 2050 summer RA eligible capacity resulting from the mass GHP deployment in the Base and the Grid Decarbonization scenarios. The summer RA eligible capacity requirement is reduced by 102 GW after deploying GHPs in the Base or the Grid Decarbonization scenario. However, the makeup of the reductions differs substantially between the two scenarios, reflecting the types of resources built primarily for satisfying RA rather than energy. In the Base scenario, most reductions come from natural gas combustion turbines and combined cycle plants, with the next-largest fraction coming from battery storage. In the Grid Decarbonization scenario, with all CO_2-emitting power plants retired by 2050, the largest contributor to the summer RA eligible capacity requirement reduction comes from H_2-CT. There is a similar reduction in battery storage capacity in the Base and Grid Decarbonization scenarios, with both seeing reductions in 6 and 8 h duration batteries. The Grid Decarbonization + GHP scenario has a greater reduction in solar RA eligible capacity, primarily because of the larger share of PV battery hybrid plants, which maintain a higher capacity credit under high-VRE scenarios compared with traditional PV plants.

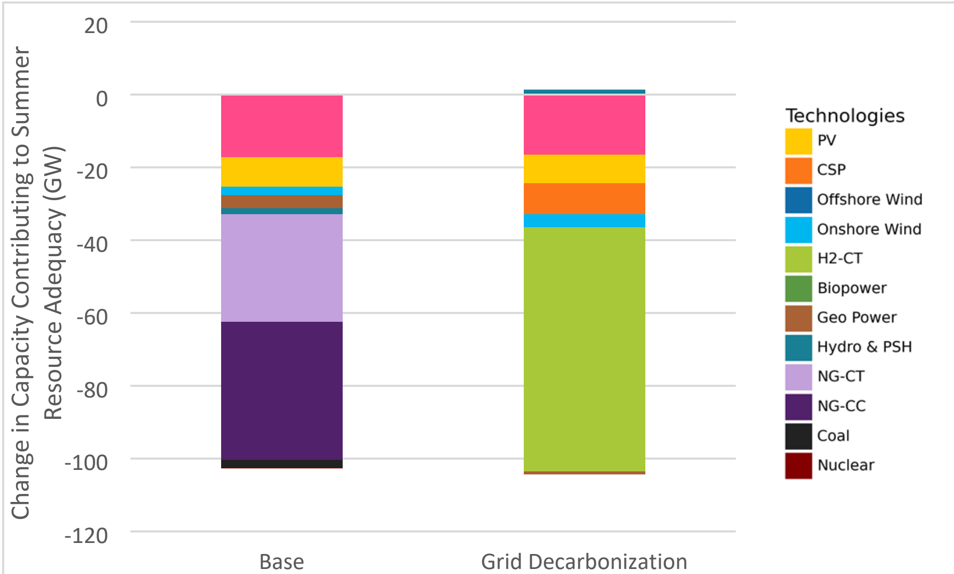


Figure 4-4. Changes in 2050 summer RA eligible capacity in the Base and the Grid Decarbonization scenarios resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes.

The noncoincident peak demands of the studied four core scenarios are listed in Table 4-2. To ensure sufficient capacity for RA, a planning reserve margin applied to each region, the summation of the regional seasonal peak demand, or noncoincident peak, is closely related to this requirement. Although spatially correlated, the exact day and hour on which peak demand occurs in each region varies, and a noncoincident peak will exceed the national coincident peak, which is the maximum demand nationally occurring at a specific day and hour. The total noncoincident peak demand in 2022 is 650 GW and will be used as a reference to analyze the peak demand growth. As shown in Table 4-2, in both the Base and the Grid Decarbonization scenarios, the mass deployment of GHPs (including weatherization in SFHs) will significantly reduce the national noncoincident peak demand in 2050. This result means by adopting the GHP technology, much less new generation capacity is needed to meet the electricity demand and to address RA needs. In other words, the expansion investment of both generating units and transmission lines can be relieved with the mass GHP deployment, which has already been validated in the capacity mix analysis and transmission expansion requirement analysis. Of note in the Grid Decarbonization + GHP scenario, reductions in H_2-CT would also reduce the investments in pipelines, storage, and hydrogen production facilities that are needed to support green hydrogen.

Table 4-2. Noncoincident peak demand comparison between 2022 and 2050 for four core scenarios

Year and case		Noncoincident peak demand (GW)	Increase from 2022 (%)
2022		650	—
2050	Base	839	29.0
	Base + GHP	697	7.2
	Grid Decarbonization	841	29.3
	Grid Decarbonization + GHP	700	7.7

4.2.1.4 CO_2 Emissions

The CO_2 emissions in this section are reported in million metric tons (MMT) of emitted CO_2 instead of the CO_2e used in Section 3. The CO_2 measures the total combustion emissions, and CO_2e includes additional GHG effects associated with a specific fuel (e.g., pipeline leakage in natural gas distribution). The CO_2 emissions were focused on in this section because the implemented decarbonization policy is a cap on those emissions and not CO_2e, mirroring the scope of CO_2 policies such as the Regional Greenhouse Gas Initiative.

The electric sector CO_2 emissions are shown in Figure 4-5. In the Base + GHP scenario (dashed-blue line), the deployment of GHP will lead to a reduction in CO_2 emissions, relative to a no-deployment Base scenario (solid blue line), because the total electric load (TWh) and peak demand (GW) are both smaller with GHP deployment by 2050, resulting in a 217 MMT/year reduction by 2050. However, the emission of the Grid Decarbonization scenario (solid orange line) is identical to that of the Grid Decarbonization + GHP scenario (dashed orange line). This result is because in the Grid Decarbonization scenario, the carbon emission constraint is always binding because of the rapid 95% electric power system decarbonization target in 2035 and complete decarbonization in 2050. GHP deployment rates assumed in this study are not aggressive enough to alter the power generation emissions.

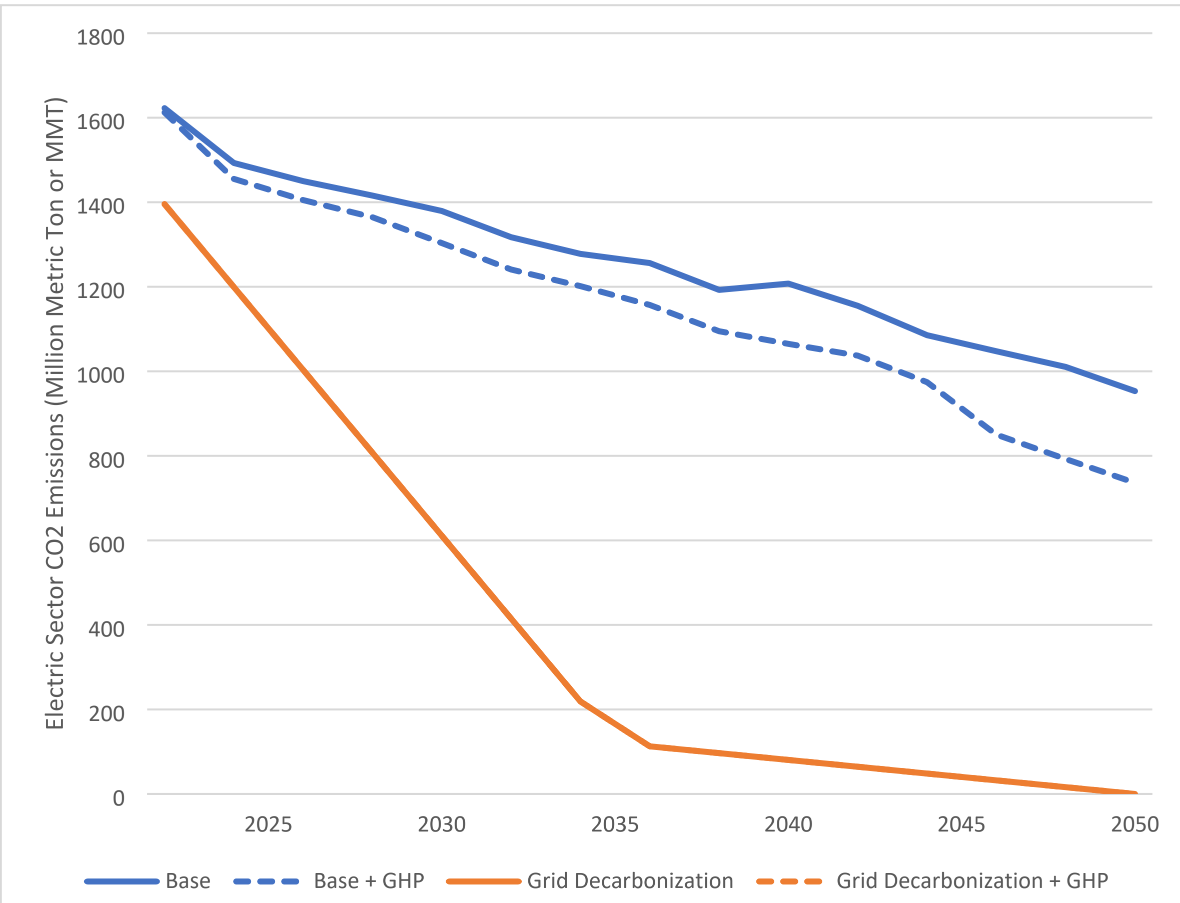


Figure 4-5. Electric sector CO_2 emissions in four core scenarios from 2022 to 2050. Note that the Grid Decarbonization + GHP scenario has identical emissions as the Grid Decarbonization scenario.

In addition to reducing electric power systems' emissions as shown in Figure 4-5, GHPs also displace end-use heating fuels such as natural gas and heating oil. Combined electric and building sector emissions are analyzed in this subsection. Figure 4-6 illustrates the combined electric and building sectors emissions for the four core scenarios from 2022 to 2050. In contrast to the electric sector–only emission scenarios, GHP deployment measurably diverges from the no-deployment counterparts. The increase in the combined electric and building sectors emissions following 2035 in the Grid Decarbonization scenario is a result of the decarbonization policy being applied solely to electric power emissions. The remaining 5% of electric power emission reductions are offset by increases in emissions in buildings. The amount of avoided end-use emissions from deployment of GHPs (including weatherization in SFHs) is sufficient, if credited, to help achieve the net-zero emissions goal of the electric power system by 2035.

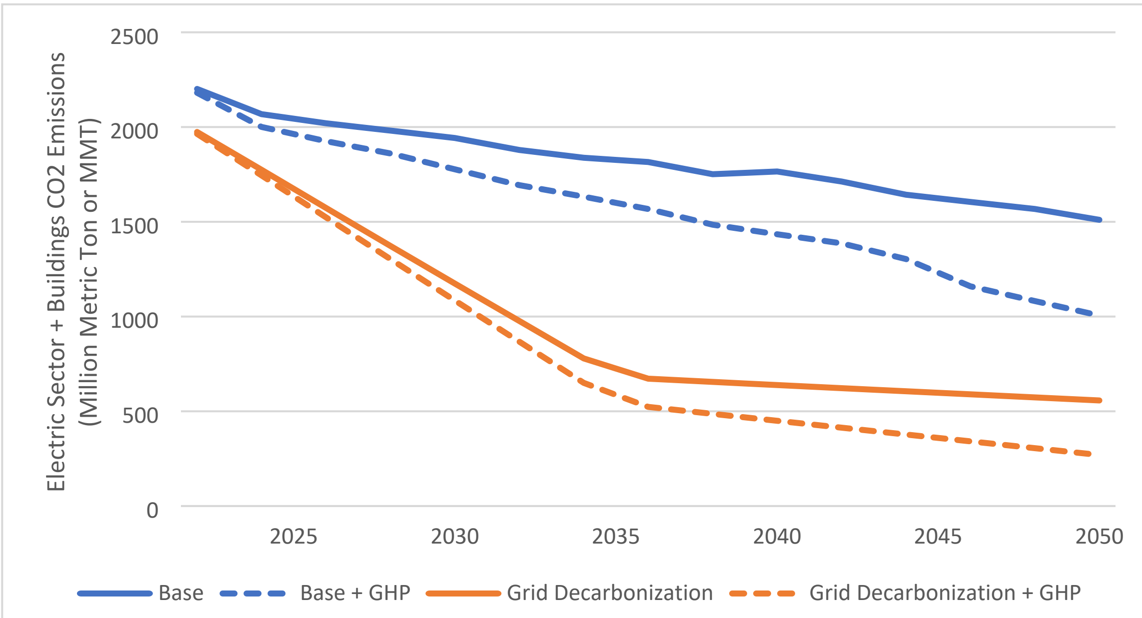


Figure 4-6. Combined electric and building sectors CO_2 emissions with and without GHP deployment (including weatherization in SFHs) in the Base and the Grid Decarbonization scenarios from 2022 to 2050.

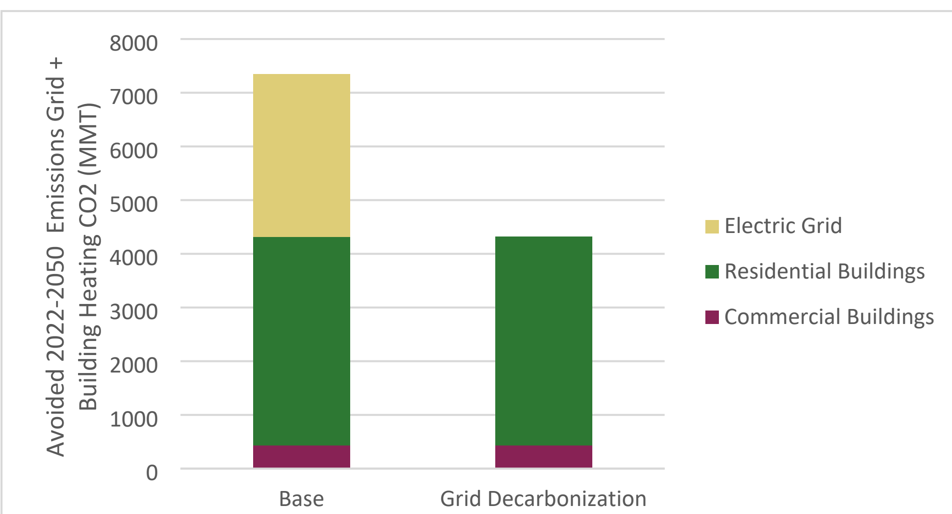


Figure 4-7 shows the cumulative CO_2 emission reductions in the combined electric and building sectors from 2022 to 2050 resulting from 100% GHP deployment in all applicable buildings for the Base and the

Grid Decarbonization scenarios. The avoided end-use heating CO_2 emission from GHPs are still counted toward the combined electric and building sectors CO_2 emission. In the Base scenario, the deployment of GHP will contribute 7,351 MMT CO_2 emission reduction in total, where 3,033 MMT comes from electric sector, and the balance of 4,318 MMT comes from the reduction of on-site fossil fuel combustion for space heating in the building sector. In the Grid Decarbonization scenario, the deployment of GHPs primarily reduces the end-use CO_2 emission at buildings by 4,320 MMT from 2022 to 2050, with small and unreported CO_2 emission reduction from the electric sector.

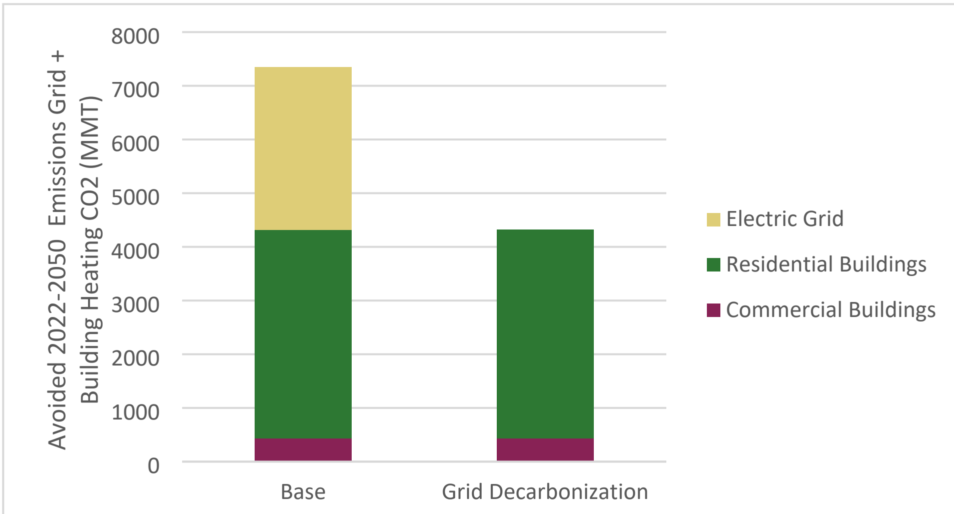


Figure 4-7. Cumulative combined electric and building sectors CO_2 emission reduction from 2022 to 2050 resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes, in the Base and the Grid Decarbonization scenarios.

4.2.1.5 Marginal System Cost of Electricity

The national-average marginal system cost of electricity from 2022 to 2050 is shown in Figure 4-8 for the Base and the Grid Decarbonization scenarios with and without GHP deployment. The marginal system cost is composed of the locational marginal price of electricity, the marginal price of capacity for the planning reserves, the marginal price of operating reserves, and the marginal credit price of renewable portfolio standards.[22] The national-average marginal system cost of electricity in 2050 is listed in Table 4-3 along with the predicted total savings in electricity payments by consumers resulting from the mass GHP deployment in the two scenarios for 2050 and the cumulative savings from 2022 to 2050.

As expected, the marginal system cost of electricity is much higher for the Grid Decarbonization scenarios than the Base scenarios because of the replacement of existing fossil-fired power plants with zero-CO_2 power plants to achieve 100% grid decarbonization. Investment in VRE substantially increases with grid decarbonization, as does long-distance transmission construction to support the geographic diversity of the VRE resources. The ability for VRE to contribute to resource adequacy declines; therefore, energy storage and expensive power plants (i.e., H_2-CTs) are needed to ensure resource adequacy. New capital expenditures, even for resources with zero operational costs, increase the system

[22] The locational marginal price of electricity, or *energy price*, is most analogous to the PLEXOS electricity price discussed in Section 4.3 but will differ because PLEXOS can capture more extreme prices in its hourly representation compared with the 17 time-slice representation used in ReEDS. The additional temporal granularity and inclusion of generator unit commitment that are accounted for in PLEXOS reflects a greater degree of operational inflexibility, which can result in higher electric power prices compared with that predicted with ReEDS, which is a capacity expansion model.

cost of electricity, which must be recovered through electric rate payers or, in the case of tax incentives, the government.

The reduction in peak demand and flattening of annual energy use resulting from the mass GHP deployment (including weatherization in SFHs) lowers the marginal system cost in both the Base and the Grid Decarbonization scenarios relative to the non-GHP scenarios. The Base scenario makes use of the existing natural gas and coal plants, many of which have already recovered their initial investment cost, resulting in comparatively small cost savings. The reductions in capacity investment, fuel, and O&M costs create a consistent but small change (a 6% decrease) in the marginal system cost of electricity in the Base + GHP scenario in 2050.

With Grid Decarbonization, the marginal system cost of electricity attains a $10/MWh differential by 2036. By 2050, the GHP deployment has reduced the cost for transitioning the existing grid to a decarbonized grid by approximately 30%. This greater reduction in the marginal system cost is explained by the types of capacity and generation changes that occur in the Grid Decarbonization scenarios. To meet 100% grid decarbonization, there is a greater investment in new carbon-free generation and storage, which displaces existing CO_2-emitting generation that has been paid for. The deployment of GHPs reduces the new investment required to meet capacity and energy needs, yielding a greater savings in marginal system cost than in the Base + GHP scenario. The calculated annual (2050) and cumulative (from 2022 to 2050) savings in electricity payments by consumers are presented in Table 4-3.

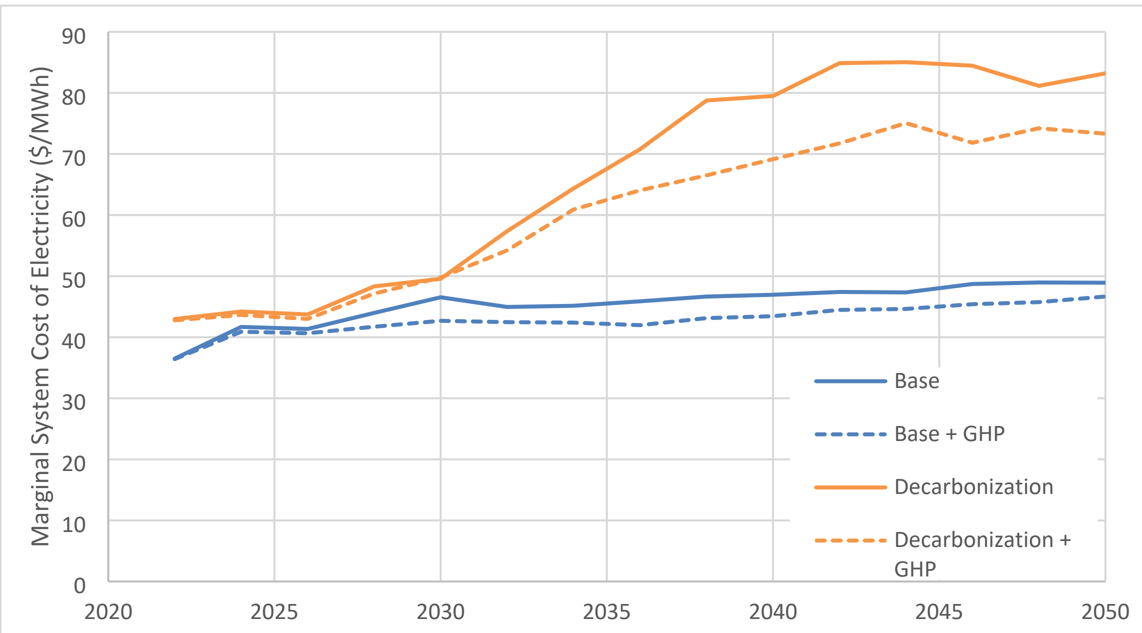


Figure 4-8. National-average marginal system cost of electricity from 2022 to 2050 with and without GHP deployment (including weatherization in SFHs) in the Base and the Grid Decarbonization scenarios.

Table 4-3. Comparison of marginal system cost of electricity and electricity payments by consumers in 2050 and from 2022 to 2050 with and without GHP deployment (including weatherization in SFHs) in the Base and the Grid Decarbonization scenarios

Scenario	Marginal cost ($/MWh)	2050 values of annual electricity payments ($ billions)	Present value of cumulative electricity payments from 2022 to 2050 ($ billions)

No GHP	Base	49	—	257	—	3,206	—
	Grid Decarbonization	83	—	437	—	4,444	—
With GHP	—	—	**Savings ($/MWh)**	—	**Savings ($ billions)**	—	**Savings ($ billions)**
	Base	46	**3**	218	**39**	2,877	**329**
	Grid Decarbonization	73	**10**	342	**95**	3,862	**582**

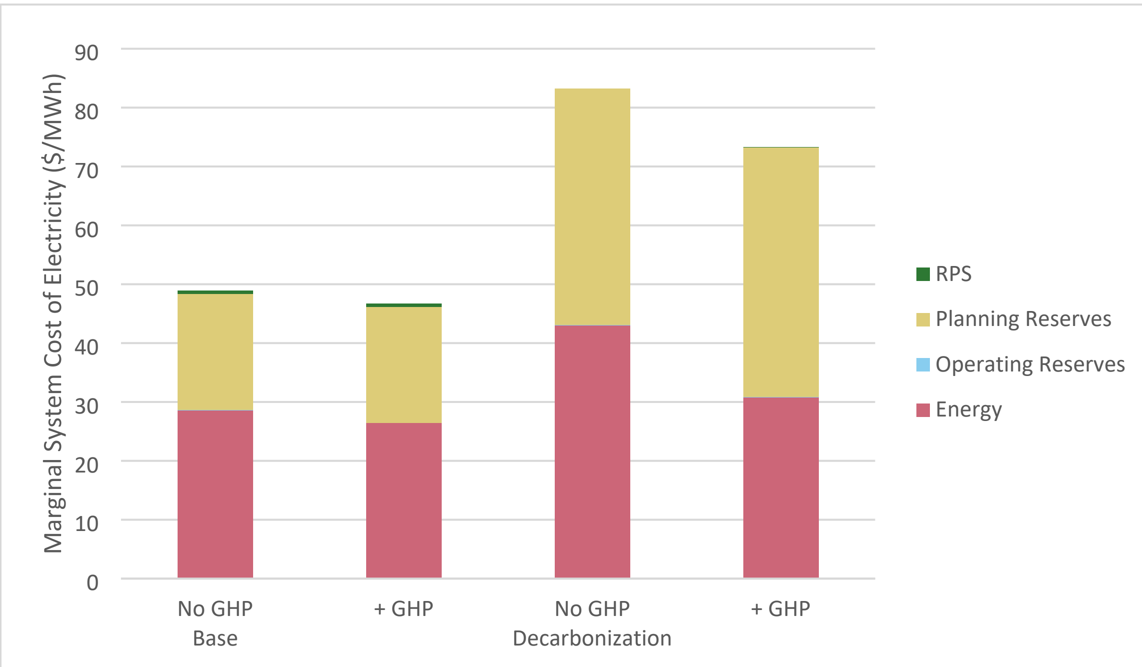


Figure 4-9 shows the breakdown of the marginal system cost of electricity in the four core scenarios in 2050. As shown in this figure, the electricity price mainly consists of the energy price (red bar) and planning reserve price (yellow bar). In the Grid Decarbonization scenarios with and without GHP, the planning reserve price has a larger share because more firm generation capacity needs to be developed to support a high-VRE system while retiring existing natural gas and coal power plants.

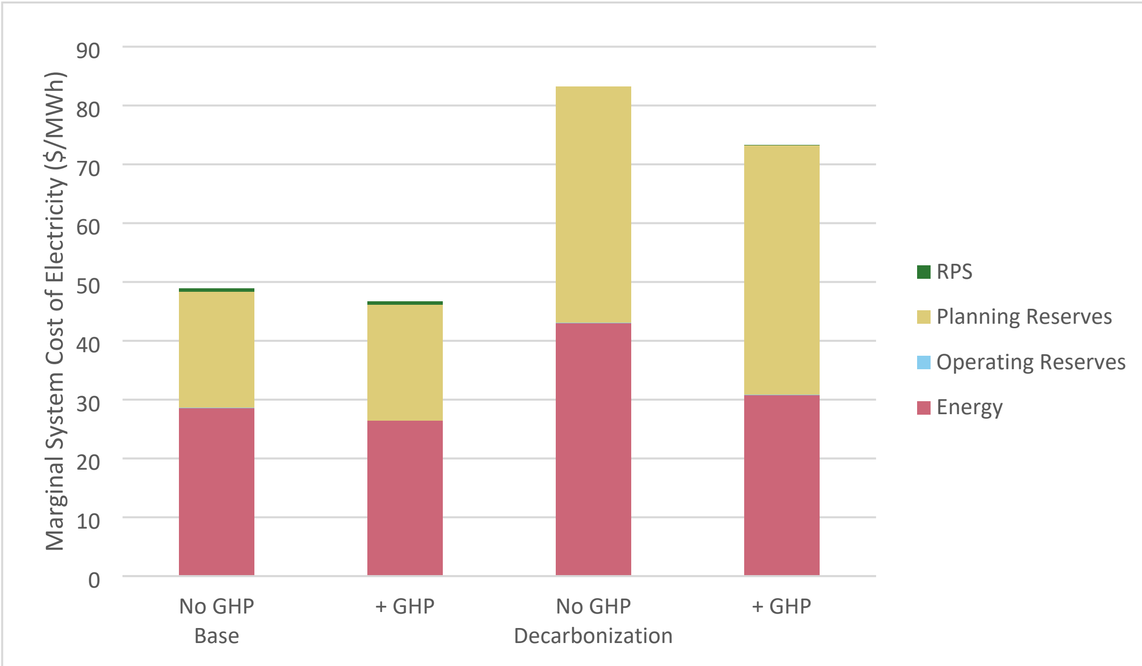


Figure 4-9. Breakdown of the marginal system cost of electricity in 2050 with and without GHP deployment (including weatherization in SFHs) in the Base and the Grid Decarbonization scenarios.

4.2.1.6 System Costs and Benefits

The total cumulative discounted system costs of the four core scenarios are shown in Figure 4-10. The values shown are the present value of the cumulative power system costs (from 2022 to 2050 with 5% discount rate). The metric is related to the marginal system cost of electricity described in the prior section, which characterized the types of services and prices that consumers of electricity would pay to generators and grid operators; the cumulative system cost captures the total costs of investment and operations to electric power generators and grid operators. The system cost is a holistic measure to assess effects of the mass GHP deployment on the electric power system and can be broken down by distinct categories of expense, including capital costs for generation, storage, and transmission, as well as operational costs, including fuel and O&M. Avoided costs outside of the electric power system are not included in this calculation, including changes in building fuel costs.

In the Base and the Grid Decarbonization scenarios, the deployment of GHP technology reduces the total system cost. The total system cost savings are $145 billion and $241 billion in the Base + GHP scenario and the Grid Decarbonization + GHP scenario, respectively. As a percentage, these savings are a 5.1% reduction in the Base + GHP scenario and a 7.2% reduction in the Grid Decarbonization + GHP scenario. The higher cost reduction with GHP in the Grid Decarbonization + GHP scenario is primarily due to greater savings in generation capital costs and transmission investment compared with the changes seen in the Base + GHP scenario.

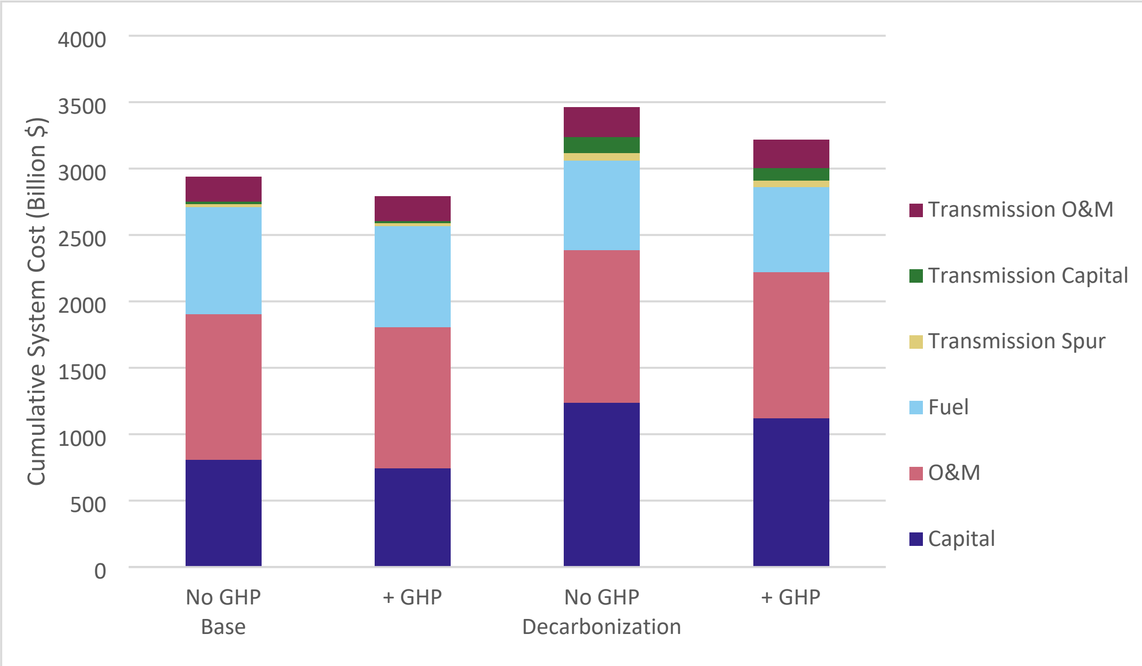


Figure 4-10. Cumulative discounted system cost (2022 to 2050 with 5% discount rate) with and without GHP deployment (including weatherization in SFHs) in the Base and the Grid Decarbonization scenarios.

4.2.1.7 Electrification Sensitivity

The EFS scenario, analyzed in this subsection, considers the electrification of other sectors such as transportation. The EFS scenario also incorporates the Grid Decarbonization assumptions (i.e., reduce emissions by 95% in 2035 and 100% in 2050). Electrification potentials in the original EFS were calculated using the EnergyPATHWAYS model, which is a bottom-up energy sector tool that measures changes to the end-use technology based upon regional stock changes and prescribed assumptions about change to market share of end use technologies. In the EFS high-electrification scenario, ASHPs will be installed in 68% and 46%, respectively, of all residential and commercial buildings existing in 2050. The underlying assumptions achieve only partial electrification of heating and cooling in residential and commercial buildings. Electric demands increase in the EFS scenarios as transportation, industry, residential, and commercial energy uses that were previously met with fuels are electrified. Therefore, the total installed electric power generation capacity in the EFS scenario is much larger than the Grid Decarbonization scenario, with an increase of 1,090 GW in capacity and 1,900 TWh in annual generation.

For this analysis, the high-electrification scenario from EFS was first modified to remove changes in electricity use for heating and cooling in residential and commercial buildings (i.e., without electrification in heating and cooling). Then, GHP deployment in all applicable buildings (78% of residential buildings and 43% of commercial buildings) was applied consistent with the methodology used in the core scenarios. This method created a new electrification scenario that is consistent with the high-electrification scenario of EFS but uses GHP deployment (including weatherization in SFHs) for electrifying residential and commercial heating and cooling. The changes in generation capacity mix and the annual electricity generation in 2050 in the EFS scenario resulting from the mass GHP deployment is presented in Figure 4-11. Electrifying building space heating and cooling with GHPs, along with weatherization in SFHs, reduces electricity capacity and generation requirements by 410 GW and 937 TWh, respectively, compared with the original EFS scenario with high electrification.

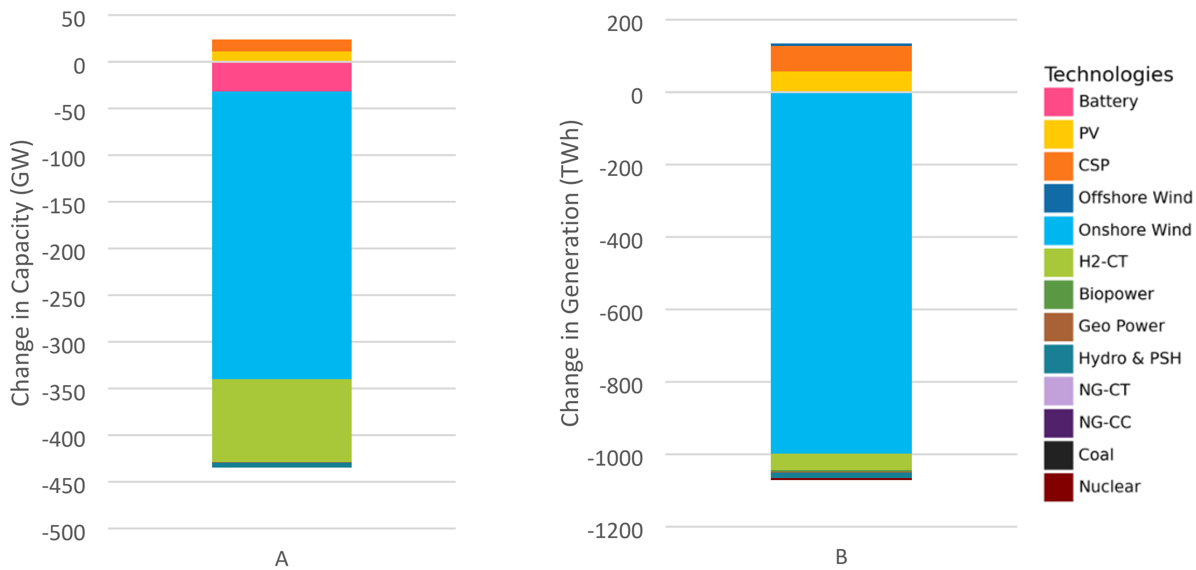


Figure 4-11. Change in (A) national electricity generation capacity and (B) national annual electricity generation in the EFS scenario in 2050 resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes.

Compared with the core scenarios, the mass GHP deployment in the EFS has an increased ability to reduce resource adequacy requirements in cold climate regions, which previously relied heavily on natural gas for heating. This effect would be greater if the original EFS had fully electrified heating and cooling, as was studied in *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035* (Denholm et al. 2022). The change in seasonal RA eligible capacity contributions toward the planning reserve margin is shown in Figure 4-12. In contrast to the capacity changes shown in Figure 4-11, bulk reductions in RA eligible capacity are from H_2-CT and battery storage. It can also be observed that RA eligible capacity from solar (PV and CSP) increases in summer while hydropower (hydropower and PSH) increases in winter, which is thought to be due to the wide geographic coverage of GHP applications so that more renewable energy can be accessed. The GHP deployment in the EFS scenario shows a higher reduction in winter peak resource adequacy requirements than in summer, which has increasing importance in EFS, where electrification of heating with ASHPs results in an increasing number of regions shifting from summer peaking to winter peaking.

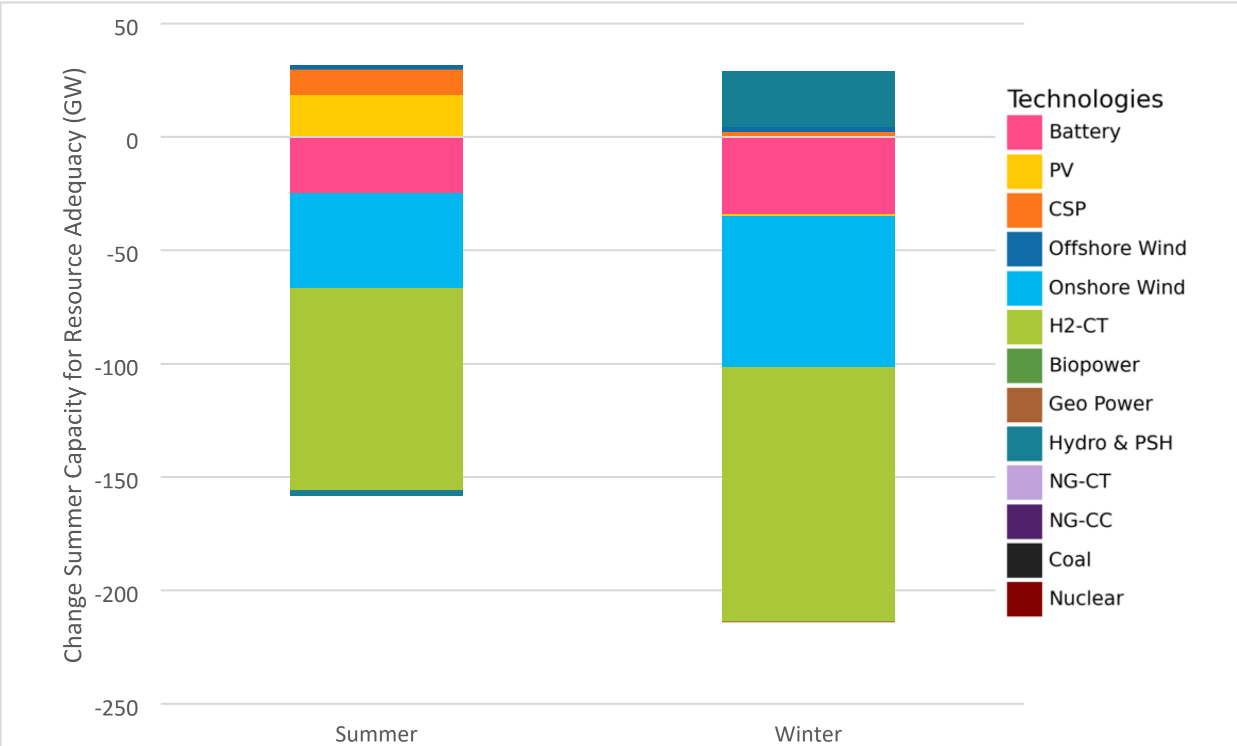


Figure 4-12. Change in summer and winter RA eligible capacity contribution by technologies in the EFS scenario resulting from the mass GHP deployment (including weatherization in SFHs) instead of the partial electrification using ASHPs.

Interregional transmission has a greater buildout in the EFS scenario compared with the core scenarios because of the high deployment of VRE. As shown in Table 4-4, with GHP deployment, interregional transmission is reduced by 65.4 TW·mi, representing a 38% reduction (or $39.5 billion less cost in present value) in new investments. The EFS scenarios directly compared two solutions for electrifying building heating and cooling. The higher efficiency of GHPs relative to ASHPs results in a larger impact relative to the Grid Decarbonization scenarios (see Table 4-4), reducing required transmission expansion by a factor of 1.8 and the present value costs by a factor of 1.3. The comparably lesser effect on the present value costs is a result of the timing of EFS transmission investments, which diverges from the Grid Decarbonization scenarios after 2035.

Table 4-5. Comparison of the interregional transmission expansion requirements in the EFS scenario with and without GHP deployment (including weatherization in SFHs)

Scenario	New + existing transmission in 2050 (TW·mi)	New transmission in 2050 (TW·mi)	Reduction (TW·mi)	Reduction (%)	Present value of transmission capital cost savings with 5% discount rate ($ billions)
No GHP	322	174	—	—	—
With GHP	256	108	65.4	37.7	39.5

Table 4-5 lists the economy-wide emissions in all analyzed scenarios from 2022 to 2050 with and without GHP deployment, respectively. The EFS scenarios show a comparably smaller reduction in economy-wide emissions with GHPs. This result is because the EFS scenario has reduced economy-wide emissions compared with the Base and the Grid Decarbonization scenarios through electrification of both the electric and building sectors.

Table 4-5. Comparison of economy-wide CO_2 emissions in the Base, Grid Decarbonization, and EFS scenarios with and without GHP deployment (including weatherization in SFHs)

Scenario		Economy-wide emissions in 2050 (MMT)		Cumulative emissions from 2022 to 2050 (MMT)	
No GHP	Base	4,529		136,063	
	Grid Decarbonization	3,576		111,129	
	EFS	2,284		94,737	
			Difference		Difference
With GHP	Base	4,024	505	128,712	7,351
	Grid Decarbonization	3,288	288	106,811	4,318
	EFS	2,153	131	92,559	2,178

4.2.2 Detailed Scenario Analysis in 2050 with PLEXOS

Hourly simulation of the electric power system in 2050, which was identified with the capacity expansion modeling (CEM) using ReEDS, was performed with PLEXOS to conduct production cost modeling (PCM) for the four core scenarios discussed in the preceding subsections. PLEXOS results provide a more granular understanding of GHP impacts on the electric power system. In contrast to CEM, PCM provides a higher degree of temporal granularity and includes operational constraints such as unit commitment, ramp rates, and up times of electricity generation. PCM results complement CEM analysis by identifying additional details that are otherwise simplified in the CEM and by providing validation of the operability of an electric power system identified by CEM. The PLEXOS results regarding the grid operations are analyzed in this subsection. The terms in this subsection are explained in the nomenclature page at the beginning of this report.

4.2.2.1 Validation of CEM Results of ReEDS

Sufficient resource adequacy should be provided in an electric power system to minimize the unserved demand, which could result in blackouts or brownouts. The electric demand change resulting from the mass GHP deployment is substantial and it merits a validation of the electric power system identified with CEM results of ReEDS. The validation is performed by comparing key results determined with ReEDS and PLEXOS, respectively.

PLEXOS can allow the load to go unserved if the demand required cannot be met with the available generation, storage, and transmission capacity. An unserved load incurs a significant penalty cost and is used by the model as a last resort. Significant quantities of unserved loads would be a key indicator that the capacity expansion solution determined by ReEDS is underbuilt for the simulation year.

In the findings for all four core scenarios, shown in Table 4- and Table 4-, minimal unserved loads were found, indicating that the capacity expansion solution is sufficient. In the Base and the Grid Decarbonization scenarios without GHP deployment, there are 4 and 9 GWh of annual unserved load, respectively. However, no unserved load was observed in these scenarios if GHPs were deployed.

Table 4- and Table 4- summarize the key metrics reported by PLEXOS for the Base scenario and the Grid Decarbonization scenario, respectively, with and without GHP deployment. Some of these metrics, including power generation capacity and battery energy capacity, directly reflect ReEDS results and they were used to confirm that the electric power system modeled with PLEXOS is an accurate translation from the capacity expansion solution determined by ReEDS. Also included in these tables are metrics that capture operational results that are not reported directly by ReEDS.

Table 4-6. PLEXOS results for the Base scenario with and without GHP deployment (including weatherization in SFHs) in 2050

	Base	Base + GHP	Reduction	Reduction ratio (%)
Annual load (TWh)	5,709	5,091	618	10.8
Annual generator revenue ($ billions)	182	125	57	31.5
Annual average wholesale electricity price ($/MWh)	32	24	8	23.2
Annual operating reserve provision (TWh)	457	413	44	9.5
Annual unserved load (GWh)	4	0	4	100.0
Annual peak demand (GW)	963	839	124	12.9
Generation power capacity (GW)	1,855	1,677	178	9.6
Battery energy capacity (GWh)	3,036	2,626	410	13.5

Table 4-7. PLEXOS results for the Grid Decarbonization scenario with and without GHP deployment (including weatherization in SFHs) in 2050

	Grid Decarb	Grid Decarb + GHP	Reduction	Reduction ratio (%)
Annual load (TWh)	5,709	5,092	617	10.8
Annual generator revenue ($ billions)	771	572	199	25.9
Annual average wholesale electricity price ($/MWh)	135	112	23	16.9
Annual operating reserve provision (TWh)	673	584	89	13.3
Annual unserved load (GWh)	9	0	9	100.0
Annual peak demand (GW)	1,062	908	154	14.5
Generation power capacity (GW)	2,532	2,198	334	13.2
Battery energy capacity (GWh)	4,362	3,809	553	12.7

A comparison between the results of PLEXOS and ReEDS indicates that these results are in agreement with differences explainable through the differences in the modeling scope between PLEXOS and ReEDS. Load results of PLEXOS show a 10.8% reduction in the annual load with GHP deployment in the Base and the Grid Decarbonization scenarios. In ReEDS, this reduction was 11.2%, showing similar reductions. The total reported load in terms of terawatt-hours is higher as reported by PLEXOS compared with that predicted by ReEDS because the PLEXOS results included the total energy used to charge battery storage.

Peak demand results of PLEXOS show a 12.9% reduction in the Base + GHP scenario and 14.5% reduction in the Grid Decarbonization + GHP scenario. The reported peak demand reduction in ReEDS is 17%. The small discrepancy between the results of PLEXOS and ReEDS is due to the differences in the reported metrics in the two models. In PLEXOS, the values reported in this section include storage charging and are a measurement of the national concurrent peak demand. In ReEDS, the peak demand is based upon the regional peak demands, which are not temporally concurrent, and does not consider battery charging. Further analysis indicates that the annual peak demand hour used in PLEXOS occurs during a summer daylight hour, which is a period with abundant solar production, incentivizing charging battery storage to meet the net peak demand period during a later time of the day. Therefore, the percentage of peak demand reduction in the PLEXOS results is lower than that predicted with ReEDS.

Another area of contrast with ReEDS is on the reported annual average wholesale electricity price and annual generator revenue (annual consumer payment for electricity). The wholesale electricity price reported by PLEXOS is equivalent to the weighted average of the locational marginal price (LMP) of electricity. LMP is an important price metric used in power markets in the United States and describes, at a specific location and time, the cost of producing the next unit of electricity. LMP is used by power markets to determine the settlement price for the energy sold by a power generator and is directly related to the generator's revenue. ReEDS has an equivalent metric for the energy component of the marginal system cost of electricity as described in Section 4.2.1.5. In the Base + GHP scenario, PLEXOS results showed a relatively larger cost reduction of 23% for LMP compared with a 7.5% reduction predicted by ReEDS. In the Grid Decarbonization + GHP scenario, PLEXOS results showed a reduction of 17% compared with 28% predicted by ReEDS. With the hourly temporal resolution, PLEXOS identified higher prices for energy in the Grid Decarbonization + GHP scenario ($112–$135/MWh) compared with ReEDS ($32–$42/MWh). It highlights a limitation of the available resolution in the ReEDS representation of power system operations.

4.2.2.2 Reliability Assessment Zone Peak Demand Results and Analysis

This section builds upon Section 4.2.1.3; a discussion of resource adequacy and its implementation within the ReEDS can be found there. This section focuses on the temporal granularity and operational detail available in the PLEXOS simulation, which gives more details regarding the operation of the electric power system in different scenarios.

Reliability assessment zones (RAZs) are aggregations of BAs used in ReEDS, within which the bulk power system is assessed to ensure resource adequacy. The RAZs are closely aligned with the regions used by NERC for regional assessments, which subdivide the interconnected power systems of North America based on the characteristics of the electric grid and the entities responsible for its operation. The area coverage of each RAZ is shown in Figure 2-4. In this subsection, the concurrent peak is calculated for each RAZ using PLEXOS. The calculation of the peak load includes the fixed hourly demand (from end uses) and grid demand for charging battery storage.

Figure 4-1 and Figure 4-13 show the PLEXOS results of peak load changes resulting from GHP deployment in each RAZ under the Base and the Grid Decarbonization scenarios in 2050 for the summer and winter, respectively. With Grid Decarbonization in nearly all regions, there is an increase in the peak load because of a higher reliance on battery storage in the electric power systems. Although peak load has historically been the benchmark for periods of the greatest stress to the electrical grid, it is different for systems with significant shares of wind and solar power. Summer afternoon peak demand coincides with high solar availability and be an opportune period for storage systems to charge using inexpensive electricity.

The increase in peak demand in the Grid Decarbonization scenario is indicative of this effect with peak demand increasing because of the charging of battery storage. The peak demand reduction resulting from GHP deployment increases in the Grid Decarbonization + GHP scenario because the hourly load reduced by GHP deployment reduces the reliance on battery storage for both summer and winter periods. This effect is observable in the Northeast Power Coordinating Council (NPCC), where peak demand reductions shown in PLEXOS results are achieved at a higher fraction for both summer and winter in the Grid Decarbonization + GHP scenario.

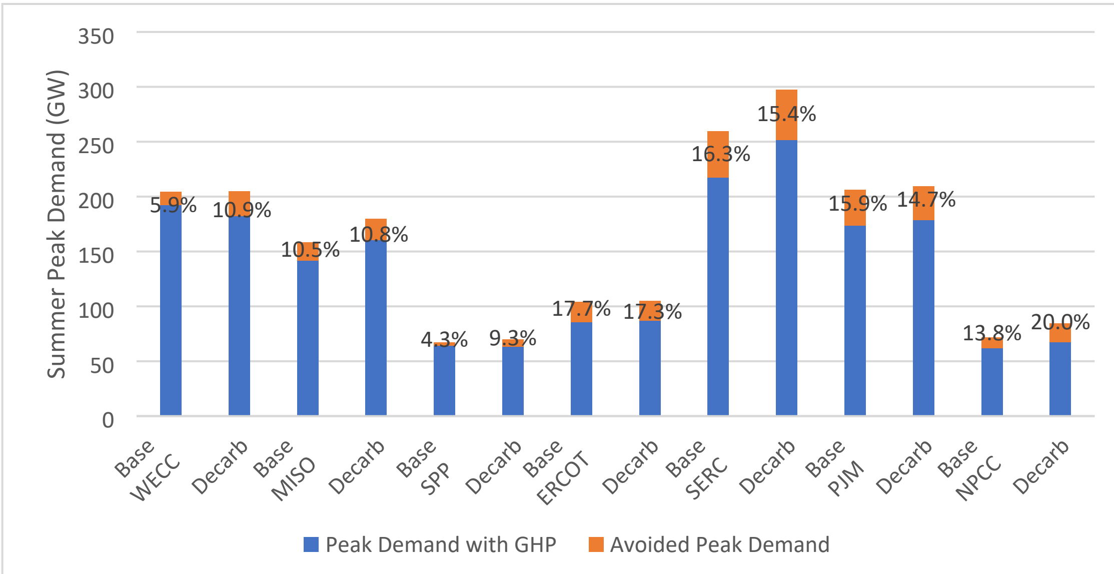


Figure 4-13. Summer peak demand in the Base and Grid Decarbonization scenarios; the blue bars are the peak demand by region, and orange bars are the avoided peak demand owing to demand reductions from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes. The percentage of avoided peak demand is shown in the figure's labels.

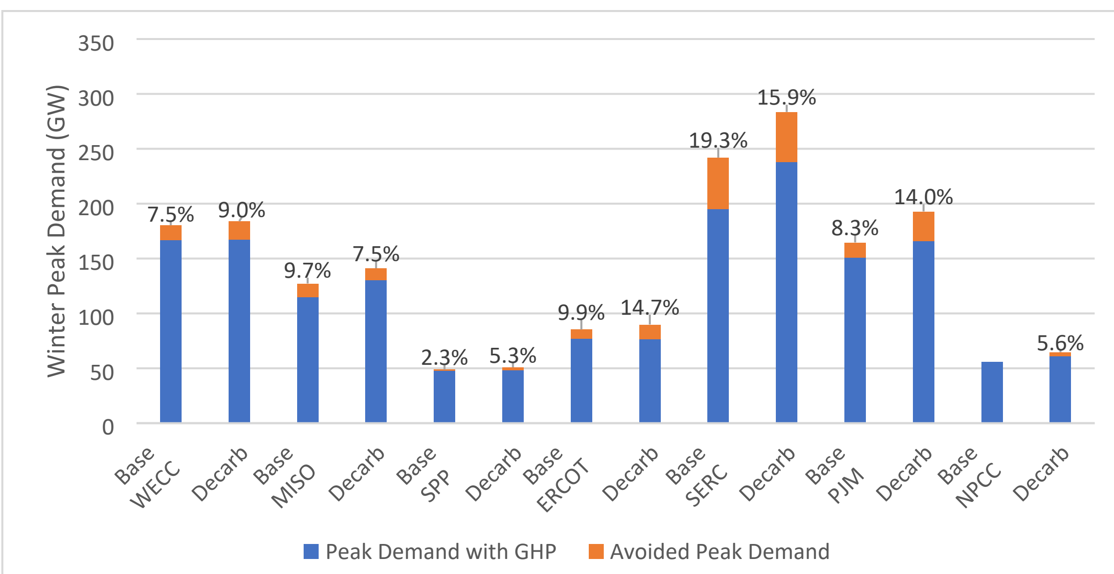
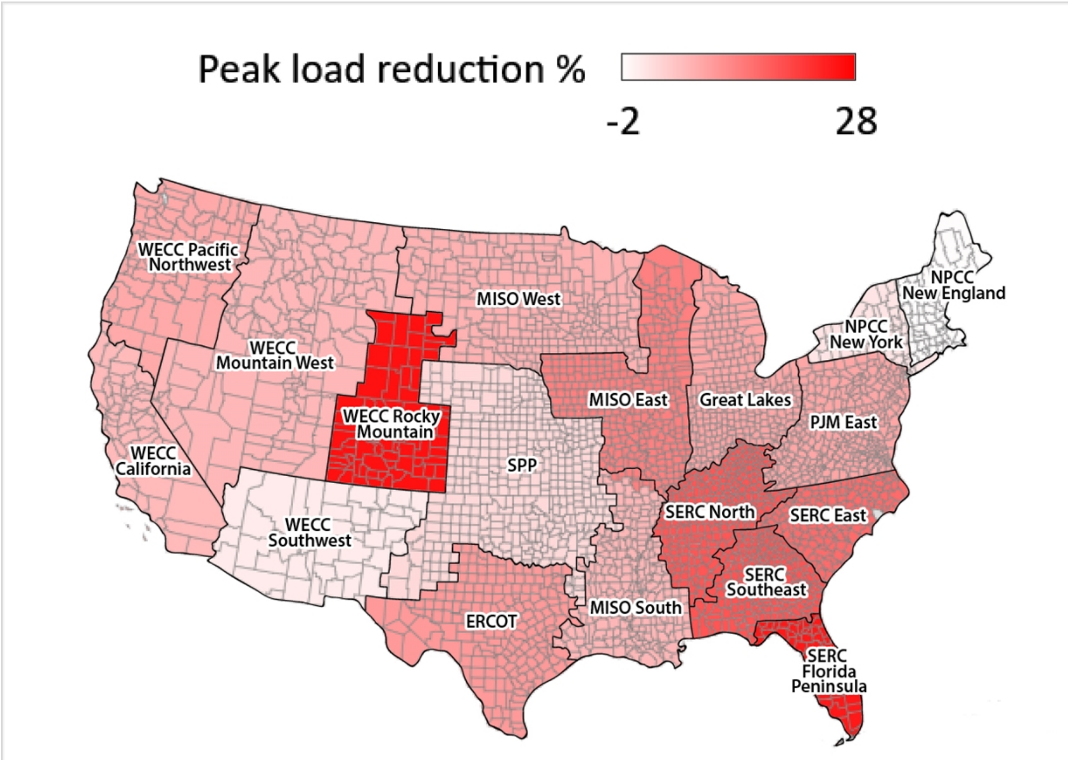


Figure 4-13. Winter peak demand in the Base and Grid Decarbonization scenarios; the blue bars are the peak demand by region, and orange bars are the avoided peak demand owing to demand reductions from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes. The percentage of avoided peak demand is shown in the figure's labels.

The seasonality results highlight the differences in effects derived from regional differences in climate and displaced HVAC technologies. Summer peak demand analysis shows reductions across all regions because of the higher cooling efficiency of the GHP system compared with existing conventional air-conditioning systems. This difference is particularly pronounced in the electric power systems managed by Electric Reliability Council of Texas (ERCOT) and SERC Reliability Corporation (SERC), which have a much higher peak demand reduction because these areas have a strong cooling demand in the summer.

In winter, the mass GHP deployment (including weatherization in SFHs) reduces peak demand most strongly in regions where heating is already electrified (e.g., using ASHPs). Here, SERC is most notable; having mild winters and a highly electrified heating system, the regional peak demand reduction ratio was 19%, and in the constituent RAZ, it was as high as 28%. In contrast, peak demand sees lower reductions in regions with high fossil fuel–dominated heating systems. In the region managed by NPCC, with harsher winters, a slight increase in electric consumption occurred in the Base + GHP scenario, with reduced battery charging in the Grid Decarbonization + GHP scenario yielding a reduction in peak demand. In these regions, the electricity consumed by a GHP for space heating is not offset by the avoided electricity for cooling, but there will be other operating costs, health, and decarbonization benefits from retrofitting fossil fuel heating systems in these regions with GHPs that fall outside of the PLEXOS analysis.

Figure 4- and Figure 4- show the percentages of avoided peak demand resulting from the mass GHP deployment for each RAZ for the summer and winter in the Base and Grid Decarbonization scenarios. In summer, the south, southeast, and east usually have a higher peak demand reduction after GHP deployment than other areas. These maps show the overlapping interactions between regional differences in climate and existing installed HVAC systems.



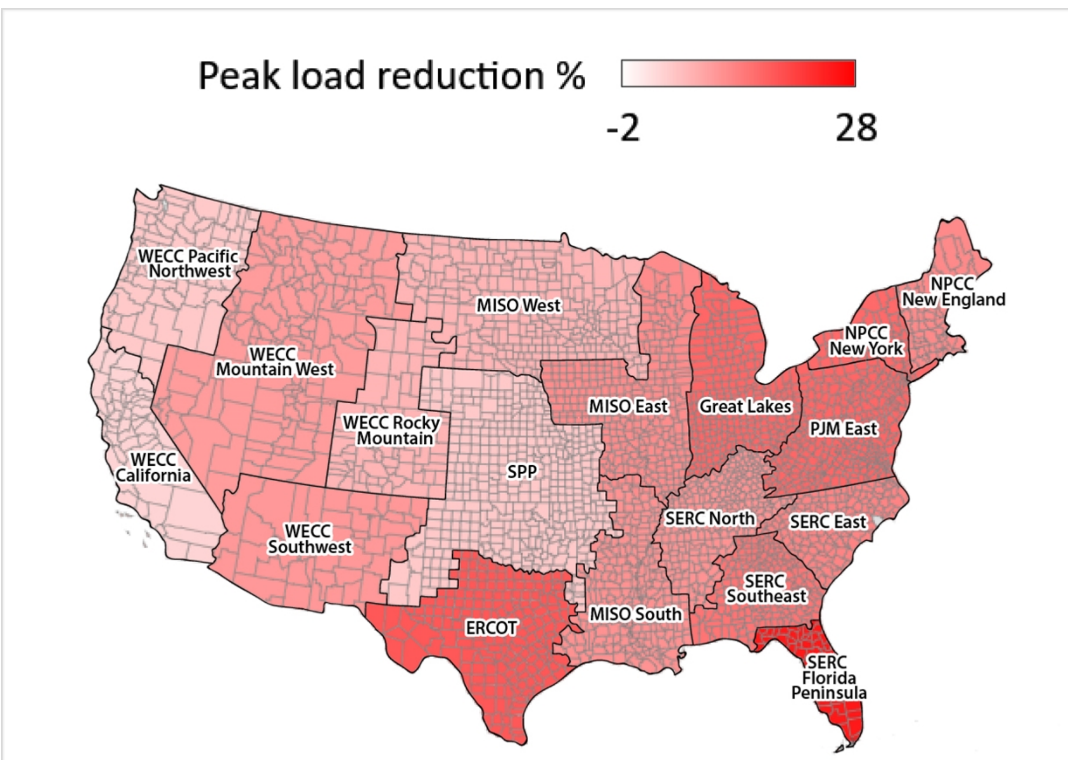


Figure 4-14. Peak electric demand reduction percentage in (top) winter and (bottom) summer at each RAZ resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes, in the Base scenario.

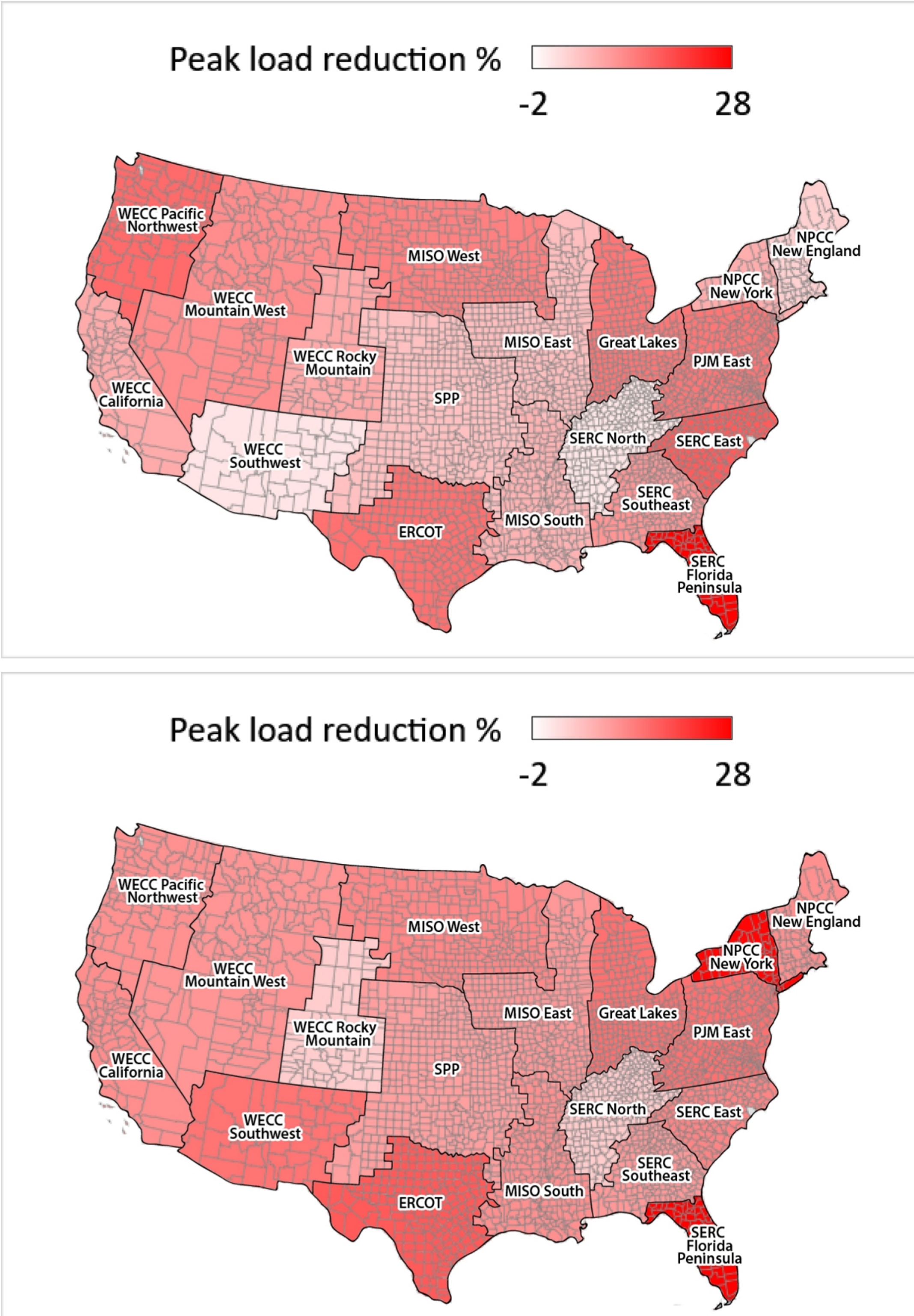


Figure 4-15. Peak electric demand reduction percentage in (top) winter and (bottom) summer at each RAZ resulting from deploying GHPs into 68% of buildings in the United States, coupled with weatherization in single-family homes, in the Grid Decarbonization scenario.

4.2.2.3 Regional (Balancing Area) Results and Analysis

To investigate the effect of GHP deployment at a finer spatial resolution, the peak demand at the BA level is examined in this subsection. Three BAs were selected based on their differences in climates and the currently used heating energy sources, including BA 1 in Western Washington, BA 94 in Georgia, and BA 134 in Maine. Table 4- and

Table 4- show the PLEXOS results of peak demand with and without the mass GHP deployment in the Base and Grid Decarbonization scenarios, respectively. Note that the timing of peak demand differs by BA because of the weather and differences in patterns of electric demand composition.

For BA 1 (Western Washington), the climate is relatively mild, so the energy consumption for heating and cooling is also moderate. It is a winter-peaking region. The GHP deployment (including weatherization in SFHs) can reduce the peak demand by 4.5% in summer in the Base scenario and achieve the same reduction in the Grid Decarbonization scenario. This BA is a highly electrified region, with only 50% of heating demand served by natural gas. GHP deployment in this BA reduces winter peak demand by 5.9% in both the Base and the Grid Decarbonization scenarios.

For BA 94 (Georgia), the summer is hot, and the winter is mild. Currently, grid demands are nearly balanced between summer and winter on the grid. Georgia also has a high degree of electrified heating within, with 60% of the building heating provided by natural gas and propane. GHP deployment reduces the summer peak by 14.1% because of the higher efficiency of the GHP in both the Base and Grid Decarbonization scenarios. In Georgia, the deployment of GHPs (including weatherization in SFHs) reduces the winter peak demand by a similar quantity as the summer peak reduction of 5 GW, or 15.3%, in the Base scenario and by 3 GW, or 9.2%, in the Grid Decarbonization scenario.

For BA 134 (Maine), the summer is warm, and the winter is very cold. Electricity makes up little of Maine's current heating demand in winter, which is mostly served by a mix of oil, propane, firewood, and natural gas. Thus, full electrification of building heating in this area increases electricity consumption. GHP deployment reduces the summer demand by 170 MW, or 7%, in both the Base and Grid Decarbonization scenarios. In contrast to other regions, there is an increase in the winter peak demand by 220 MW, or 8.3%, in the Base scenario and 140 MW, or 5.9%, in the Grid Decarbonization scenario.

Table 4-8. Regional analysis for the Base scenarios in 2050

Location	Season	Base (GW)	Base + GHP (GW)	Reduction (GW)	Reduction (%)
Western Washington	Summer (Aug. 17)	9.52	9.09	0.43	4.5
	Winter (Jan. 18)	12.62	11.87	0.75	5.9
Georgia	Summer (Jun. 30)	39.24	33.69	5.55	14.1
	Winter (Jan. 3)	33.1	28.05	5.05	15.3
Maine	Summer (Jul. 19)	2.40	2.23	0.17	7.1
	Winter (Jan. 20)	2.64	2.86	−0.22	−8.3

Table 4-9. Regional analysis for the Grid Decarbonization scenarios in 2050

Location	Season	Grid Decarbonization (GW)	Grid Decarbonization + GHP (GW)	Reduction (GW)	Reduction ratio (%)
Western Washington	Summer (Aug. 17)	9.52	9.09	0.43	4.5
	Winter (Jan. 18)	12.62	11.87	0.75	5.9
Georgia	Summer (Jun. 30)	39.24	33.69	5.55	14.1
	Winter (Jan. 3)	33.34	30.27	3.07	9.2
Maine	Summer (Jul. 19)	2.40	2.23	0.17	7.1
	Winter (Jan. 20)	2.36	2.50	−0.14	−5.9

4.3 DISCUSSION AND LIMITATIONS

The GHP impacts analysis is subject to the limitations affecting most forward-looking studies that are quantitative and qualitative. This study depends on fundamentally uncertain modeling input assumptions, including load shapes, growth, and future costs. ReEDS, PLEXOS, and the ReEDS-to-PLEXOS model translation have known limitations that were considered when analyzing results. For ReEDS-specific limitations and ReEDS-to-PLEXOS model translation limitations, see Ho et al. (2021). Both ReEDS and PLEXOS are techno-economic models and do not account for specific business structures, market power, or socioeconomic considerations. Qualitative results are limited by literature and an understanding of the conditions that would influence a future power system, which are limited by historical trends and the body of existing literature. These limitations are mitigated by collecting input from the diverse body of expertise among the authors and reviewers when drafting this report.

Changes in the electric load from GHP deployment assume linear deployment rates and no improvements in efficiency of the GHPs during the study period. Although the total deployment is aspirational, the rate of deployment and the fixed assumption around performance may be conservative. This study did not quantify the cost of GHP installation and the available land areas for installing GHP systems because the intention was to quantify the potential benefits to the grid from the GHP deployment. Future analyses accounting for the costs and efficiency improvement of GHPs, as well as constraints of available land areas, could better explore the GHP deployment rates in various markets.

Although land use is an important consideration for questions of equity and environmental impact, this study did not quantify the relative changes in land use among technologies. Reductions in solar and wind installation from the mass GHP deployment will see reductions in long-term land use. GHP deployment for commercial and residential buildings is known to have minimal long-term land use impacts.

4.4 SUMMARY

In this section, the electric power sector analysis based on ReEDS and PLEXOS simulations revealed various impacts on the electric sector from deploying GHP systems in all applicable buildings (including weatherization in SFHs). First, the mass deployment of GHPs can reduce the generation and capacity needs of the electric power system by up to 11% and 13.2%, respectively, in 2050. The peak demand in some zones can be reduced up to 28%, which will ease grid operations and defer the installation of new generation capacities. Second, the mass GHP deployment reduces the reliance on carbon-emitting power generation in the Base scenario and cuts the transmission expansion need by approximately one-third in the Grid Decarbonization scenario. Third, the deployment of GHPs can help reduce the requirements for summer and winter resource adequacy. In the Base scenario, it reduces the natural gas generation capacity requirements in the summer, whereas in the Grid Decarbonization scenario, all natural gas power plants are retired, so the summer RA eligible capacity reduction is mainly a reflection of reduced capacity requirements from H_2-CTs. In winter, the RA eligible capacity in 2050 with the GHP deployment is less than the 2022 reference, and such a reduction is even more significant in the Grid Decarbonization scenario. It can also reduce the wholesale, system-level electricity price because of the decreased peak demand, the annualized cost savings from reduced fuel use in power plants, and the relaxed reserve requirements. Importantly, these system cost reductions represent savings that could be available as incentives to reduce the cost to consumers for retrofitting buildings with GHPs.

5. PRELIMINARY REGIONAL GRID RELIABILITY ANALYSIS

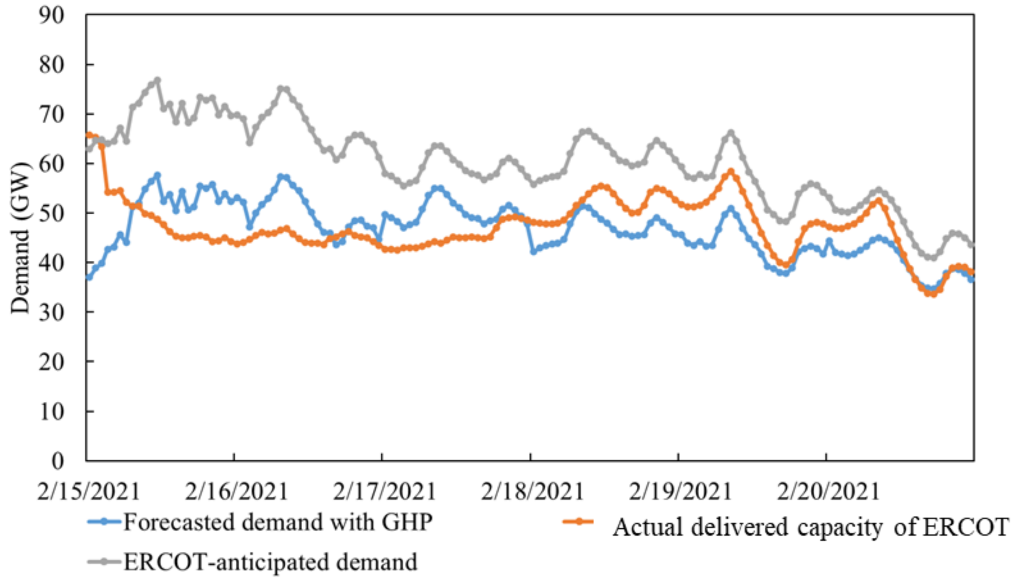
This section presents preliminary simulation results aimed at analyzing the effects of GHP deployment on grid reliability. Instead of conducting a comprehensive nationwide analysis, the focus is narrowed to assess regional grid reliability. Specifically, this section examines a blackout event that occurred during a winter storm in Texas, which commenced on February 15, 2021, and persisted for multiple days. During this severe winter storm, the electricity demand of the ERCOT power grid surged to a peak of 69 GW, surpassing the previous winter record of 66 GW. As a result, more than 4.5 million households (approximately 10 million Texans) were left without electricity at the height of this event. The associated economic losses attributable to this calamity were estimated at $130 billion (Busby et al. 2021).

The blackout event was caused by the frigid conditions brought about by the winter storm. The extreme cold weather led to a sharp decline in gas supply because of various factors such as freezing occurring at natural gas wells and gathering lines, power outages at compressor stations, and other related issues. Furthermore, the demand for gas surged significantly because approximately 40% of households in Texas rely on gas and propane for space heating during cold weather conditions. Consequently, the combination of decreased gas supply and increased consumption resulted in a shortage of approximately 30 GW in generation capacity. However, the electricity demand increased further regardless of the generation capacity shortage because approximately 60% of Texas households employ electricity for space heating. In this case, the deficiencies in the gas system, combined with insufficient generation capacity, led to significant disparity between supply and demand, which created a precarious imbalance that ultimately culminated in the occurrence of the blackout event (Busby et al. 2021).

As illustrated in the preceding sections, GHP retrofitting presents an opportunity to eliminate gas consumption and reduce the electricity demand of buildings. Given these premises, the widespread deployment of GHPs in Texas could offer a means to mitigate blackout events. To evaluate the potential effectiveness of GHP retrofitting in mitigating the 2021 winter storm blackout, a specific scenario was considered. This scenario assumes that all applicable buildings within the ERCOT had already undergone GHP retrofitting before the onset of the storm. To quantify the effects, the resulting electric demand attributable to GHP retrofitting was calculated. This value was then compared with the anticipated electric demand in the absence of GHP retrofitting, which was obtained from the EIA (EIA 2021). The historical demand (i.e., the actual delivered electric power) that was experienced in this event was limited by the capacity of the power plant. Appendix E provides more details of the calculation of the electric demand resulting from GHP retrofitting.

5.1 ANALYSIS RESULTS

Figure 5-1 presents a comparison between the anticipated electricity demand of the ERCOT and the calculated electricity demand resulting from the implementation of mass GHP retrofitting. The anticipated electricity demand was the one forecasted by the ERCOT for 2021. The calculated electricity demand with GHP retrofitting was obtained by first calculating the demand reduction owing to GHP retrofitting and then subtracting it from the anticipated electricity demand. As shown in Figure 5-1, the anticipated electricity demand exhibited a sharp increase during the 2021 winter storm. Conversely, the electricity demand was calculated to be reduced through GHP retrofitting, and the reduction is pronounced during the summer and winter. This comparison demonstrates that if all applicable buildings within the ERCOT had undergone GHP retrofitting, the anticipated electricity demand would have been significantly reduced, which would be vital in mitigating the strain on the grid such as what occurred during the 2021



winter storm.

Figure 5-2. shows three profiles of electricity demand more granularly during the 2021 winter storm. Along with the anticipated and calculated electricity demand, the delivered capacity of ERCOT recorded during the 2021 winter storm is also shown. As shown in Figure 5-2, the delivered capacity was less than the anticipated demand during the winter storm, which implies that there was a power outage. The significance of a system blackout can be measured by the difference between the delivered capacity and the anticipated electricity demand. If mass GHP retrofits were achieved in Texas before the 2021 winter storm, the newly anticipated electricity demand would become the calculated electricity demand, which is significantly smaller than the anticipated demand. Although the calculated electricity demand with GHP retrofitting is still higher than the delivered capacity for certain periods, the severity and duration of the power outage would be much smaller than that before GHP retrofitting.

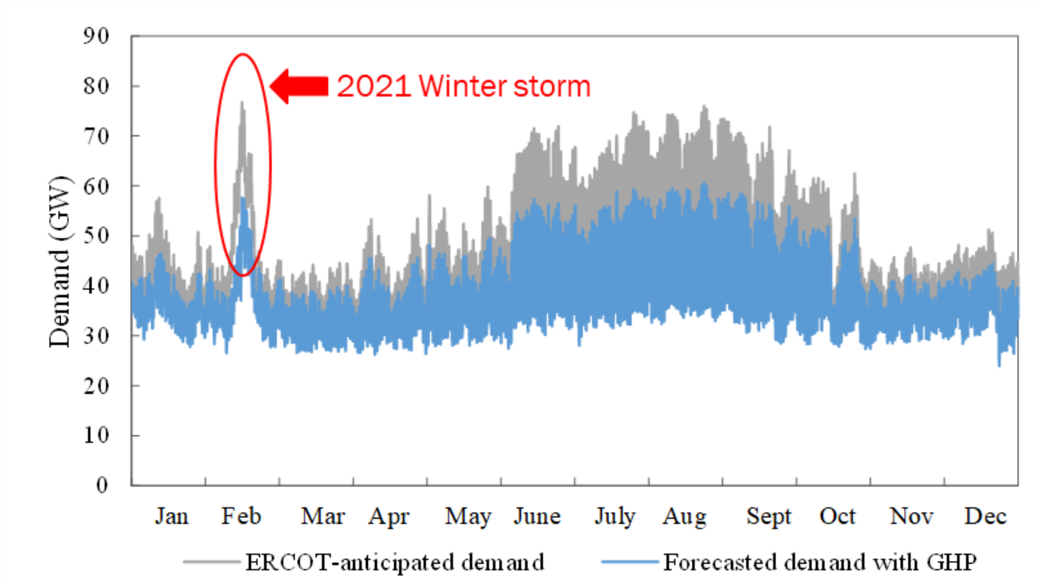


Figure 5-1. Hourly electricity demand profile of ERCOT before and after GHP retrofit in 2021.

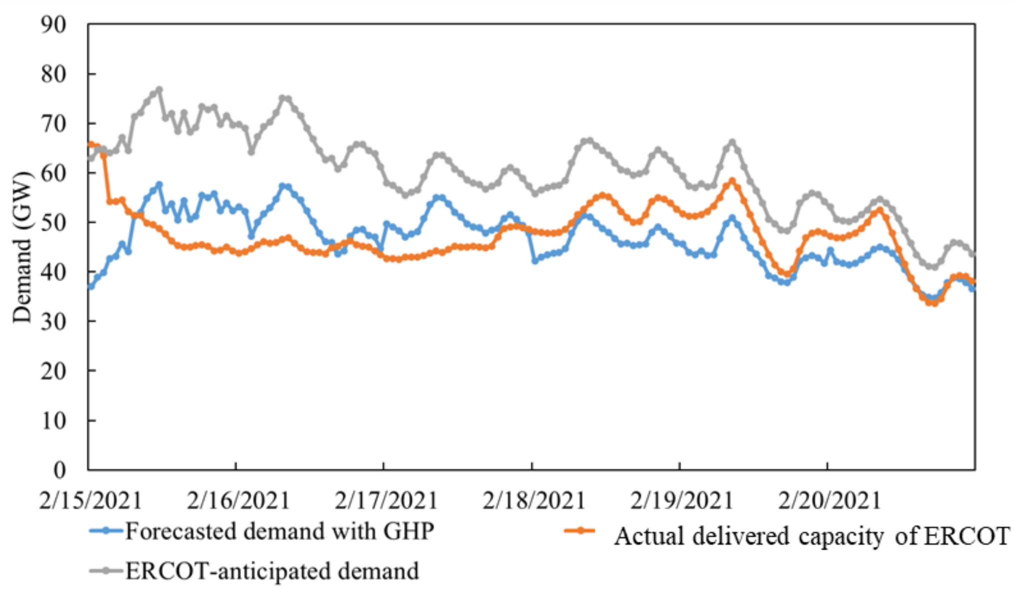


Figure 5-2. Hourly demand profiles of six consecutive days during the 2021 winter storm in Texas.

Table 5-1 provides a comprehensive overview of the most severe outage periods during the 2021 winter storm. It reveals that during these critical periods, 36.5% to 39.5% of the anticipated electricity demand was left unmet. However, when considering GHP retrofitting, the unserved electricity demand ratio would have been notably reduced, ranging from 15.4% to 20.6%. These findings strongly indicate that widespread deployment of GHPs can significantly enhance the reliability of the power system.

Table 5-1. Electricity demand during the most severe outage periods in the 2021 Texas winter storm

Time	Without GHP retrofitting	With GHP retrofitting

	Unserved demand (GW)	Served demand (GW)	Outage ratio (%)	Unserved demand (GW)	Served demand (GW)	Outage ratio (%)
2/15/2021, 11 a.m.	28.04	48.75	36.5	8.88	48.75	15.4
2/15/2021, 3 p.m.	27.10	44.96	37.6	9.43	44.96	17.3
2/15/2021, 6 p.m.	27.86	45.45	38.0	10.00	45.45	18.0
2/15/2021, 7 p.m.	27.67	45.11	38.0	9.95	45.11	18.1
2/15/2021, 8 p.m.	28.89	44.26	39.5	11.49	44.26	20.6
2/16/2021, 7 a.m.	28.51	46.56	38.0	10.82	46.56	18.9
2/16/2021, 8 a.m.	28.15	46.85	37.5	10.36	46.85	18.1
2/16/2021, 9 a.m.	27.12	45.81	37.2	9.72	45.81	17.5

Notably, the analyses presented thus far primarily focus on the reduction of electricity demand, which represents just one of the benefits achievable by GHP retrofitting. Another notable advantage is the concurrent decrease in gas consumption for heating within buildings. The saved gas can be redirected toward electricity power generation, thereby augmenting the overall power supply. Considering the interdependence of gas and electricity systems, an adequate electricity supply can enable gas supply, leading to mutual improvement and reinforcing system stability. Thus, the widespread implementation of GHPs could have potentially prevented the large-scale blackout in Texas during the 2021 winter storm.

5.2 SUMMARY

The preliminary analysis conducted demonstrates that mass GHP retrofitting can effectively enhance the operational reliability of the power grid in Texas, particularly during extreme weather conditions. This improvement stems from the substantial reduction in electricity demand achieved through GHP retrofitting, thereby reducing the strain on the power system.

Considering the ongoing effects of climate change, Texas and other areas will likely encounter a greater frequency and intensity of extreme weather events in the coming years. Notably, events such as the polar vortex experienced in December 2022 are expected to exert significant pressure on the electricity infrastructure. These circumstances are especially challenging for areas reliant on ASHPs and electric heaters for building heating and cooling. Under such circumstances, there is an increased risk of rolling blackouts or uncontrolled blackouts that affect many consumers and result in substantial economic losses. Therefore, more efficient heating and cooling systems such as GHPs must be adopted to alleviate the electricity demand burden, thereby improving the resilience and robustness of the electric power system.

6. CONCLUSIONS AND FUTURE WORK

This study began with a large-scale building stock energy simulation to assess the effects of mass GHP deployment, which is combined with weatherization of SFHs (i.e., reducing air infiltration and ductwork leakage), on electricity usage and on-site carbon emissions in the building sector. The simulation results show that retrofitting 68% of all existing building floor space in the United States (78% of residential floor space and 43% of commercial floor space of the 2018 building stock[23]) with GHP systems, along with measures for reducing OA infiltration and ductwork leakage in SFHs, can save 401 TWh of

[23] In this analysis, GHP retrofits excluded buildings that use district heating/cooling (i.e., no energy consumption for heating/cooling at the building), mobile homes, buildings without heating/cooling, and buildings that already use GHPs.

electricity and eliminate 5,138 billion MJ of fossil fuel consumption (e.g., natural gas, heating oil, propane) (approximately 4,747 billion ft^3 of natural gas equivalent) each year compared with the electricity and fuel consumption of the existing building stock in 2018. The reduced on-site fossil fuel consumption at buildings would avoid carbon emissions equivalent to 342 MMT CO_2 each year. If GHP deployment increases linearly from 2020 until reaching its maximum potential by 2050, fuel costs of US$(2021)1,020 billion would be saved, and 5,290 MMT CO_2e emissions would be avoided over 30 years by replacing the on-site consumptions of fossil fuels with GHPs for space heating.

Retrofitting existing HVAC systems with GHP systems has different effects in different regions. Large reductions in annual electricity consumption occur in the southern United States because of the dominance of air-conditioning in total annual energy use. In the northern United States, GHP retrofits result in high on-site carbon emission reductions because of the dominance of existing combustion-based heating systems (i.e., furnaces or boilers using gas, propane, and fuel oil). In many regions, the gain in efficiency during the cooling season more than offsets the increase in electrified heating load, resulting in a full building electrification with reductions in total annual electricity use. It is noteworthy that roughly 50% of the benefits described in this report (carbon, energy, and system cost reductions) are attributable to the superior efficiencies of GHPs with the remaining benefits attributable to reducing OA infiltration and ductwork leakage in SFHs. Thus, the key to realizing the enormous value proposition is through a combination of both deep efficiency measures, which should be considered for all future retrofits.

The US electric power system were analyzed in several scenarios, including Base, Grid Decarbonization, and economy-wide decarbonization (i.e., the EFS scenario). This analysis revealed various effects on the electric power system resulting from the mass deployment of GHPs (including weatherization in SFHs). The following effects can be expected if the maximum deployment of GHPs is realized by 2050:

- Reduce the requirement for annual electricity generation in the contiguous United States[24] by 585 TWh, 593 TWh, and 937 TWh compared with the Base, Grid Decarbonization, and EFS scenarios, respectively.

- Reduce the needed generation and storage capacity by 173 GW, 345 GW, and 410 GW compared with the Base, Grid Decarbonization, and EFS scenarios, respectively.

- Avoid transmission additions by 3.3 TW·mi (a 17.4% reduction), 36.7 TW·mi (a 33.4% reduction), and 65.3 TW·mi (a 37.6%) compared with the Base, Grid Decarbonization, and EFS scenarios, respectively.

- Reduce the required capacity for resource adequacy, mostly from power plants using fossil fuels, by 102 GW in summer and 95 GW in winter compared with the Base scenario. In the Grid Decarbonization scenario, 103 GW (summer) and 101 GW (winter) of capacity would no longer be needed. In the EFS scenario, substitution of ASHPs with the mass GHP deployment reduces the resource adequacy requirement by 127 GW in summer and 185 GW in winter.

- Eliminate 217 MMT CO_2 emissions each year from the US electric power system by 2050 compared with the Base scenario. However, in the Grid Decarbonization scenario, GHP deployment does not affect carbon emissions from the electric power system because the carbon emission constraint of the electric power system is determined by the predefined grid decarbonization target. GHP deployment could also avoid CO_2 emissions related to end-use heating in the building sector. The deployment of GHPs leads to a 7,351 MMT cumulative CO_2 emissions reduction from 2022 to 2050 in the Base + GHP scenario. In the Grid Decarbonization + GHP scenario, the deployment of GHPs primarily

[24] This excludes Alaska, Hawaii, and US territories because of limited data for conducting a detailed analysis.

reduces carbon emissions in the building sector (4,318 MMT from 2022 to 2050). Compared with the EFS scenario, the mass deployment of GHPs reduces 2,178 MMT cumulative CO_2 emissions from 2022 to 2050.

- Reduce the wholesale cost for electricity. The mass GHP deployment reduces peak electricity demand and flattens annual electricity use. As a result, the wholesale cost for electricity in 2050 can be lowered by 6% in the Base + GHP scenario, 12% in the Grid Decarbonization + GHP scenario, and 8% in the EFS + GHP scenario. From 2022 to 2050, the reduced wholesale cost decreases electricity payments from consumers by $316 billion in the Base + GHP scenario, $557 billion in the Grid Decarbonization + GHP scenario, and $606 billion in the EFS + GHP scenario (all present values considering a 5% discount rate).

- Reduce the cumulative system cost of electricity (including the capital costs of generators and transmission systems, as well as the costs for operating the generators and the grid) by $145 billion (a 5.1% reduction) in the Base + GHP scenario, by $241 billion (a 7.2% reduction) in the Grid Decarbonization + GHP scenario, and by $306 billion (a 7.4% reduction) in the EFS + GHP scenario.

- Reduce the peak load in all RAZs in the summer by 3% to 28%. In the winter, GHPs can also reduce the peak load for most areas; in the Southeast, where electric heating (e.g., ASHPs with supplemental electric resistance heaters) is widely used, the peak load reduction ratio can be up to 28%. Notably, the peak load is less reduced in areas where fossil fuel–based heating is used. A case study indicates that mass deployment of GHPs could improve the operational reliability of Texas electric power system in extreme winter weather events. It thus will reduce rolling blackouts, which could affect many consumers and result in high economic losses.

To address the limitations of the current study and generate more useful information to utility companies and decision-makers, the following actions are recommended:

- Conduct a regional analysis, such as for the service territory of a particular electric grid system or for a specific group of buildings in each county, to investigate the effects and costs of implementing GHPs. This analysis should include (1) CO_2 and energy cost reduction from eliminating natural gas combustion; (2) jobs to retrofit buildings and drill boreholes for implementing GHPs in applicable buildings; (3) water consumption in the electric power system resulting from mass GHP deployment, as well as water use in the cooling towers of commercial buildings; and (4) changes in grid assets (e.g., avoided lithium batteries), infrastructure development, and cost of transmission.

- Expand the building sector analysis to account for improvement in building energy efficiency, including improvement in building envelopes, the energy efficiency of conventional HVAC systems and GHP systems, and outdoor air ventilation controls.

- Develop a web-based interactive national map with built-in analytical tools to present the results of the impact analysis, including building and grid simulation results. The map will support data-driven research that explores the environmental and socioeconomic benefits associated with GHP deployment.

- Investigate the cost reduction potential resulting from the mass manufacturing of GHP units and the scale of economy for GHE installation.

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APPENDIX A. CHARACTERISTICS OF THE PROTOTYPE BUILDING MODELS USED IN THIS STUDY AND THE REPRESENTATIVE CITIES OF THE 14 US CLIMATE ZONES

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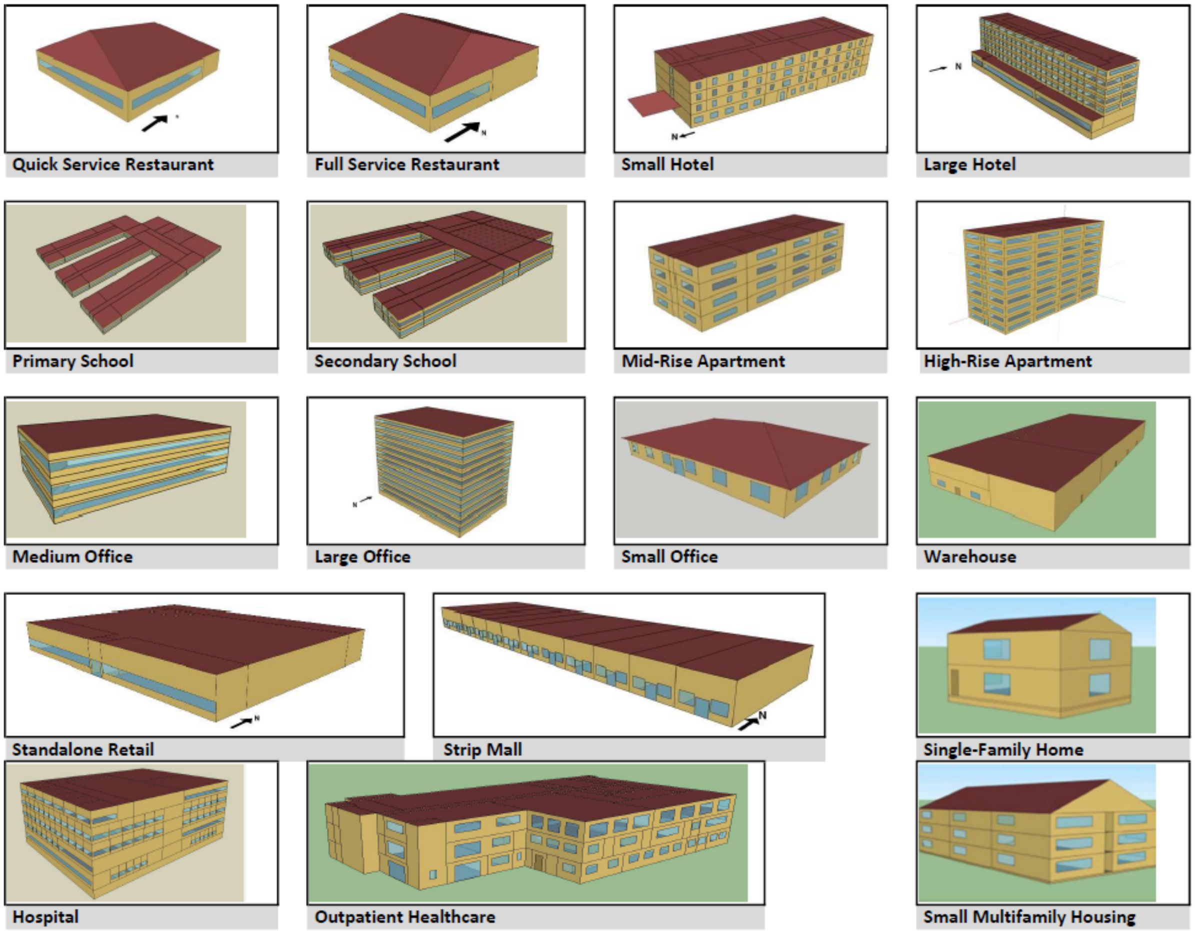

Figure A-1. 3D renderings of the commercial and residential prototype building models used in this study.

Table A-1. Total floor area and existing HVAC equipment of commercial and residential prototype buildings used in this study (designed following the 2007 edition of ANSI/ASHRAE/IES Standard 90.1 for commercial buildings and the 2006 edition of IECC for residential buildings)

Building description	Total floor area (ft^2)	Heating equipment	Cooling equipment
Small office	5,500	Heat pump with a backup gas furnace: 7.7 Heating Seasonal Performance Factor	Heat pump: seasonal energy efficiency ratio (SEER) 13
Medium office	53,600	Gas furnace: 80% burner efficiency	Packaged terminal air-conditioner (PTAC): energy efficiency ratio (EER) 9.3
Large office	498,600	Gas boiler: 80% thermal efficiency; water source heat pump: Heating COP 4.2	Water-cooled centrifugal chillers: 6.2 COP; water-source direct expansion (DX) cooling coil for data center and IT closets: EER 12

Table A-1. Total floor area and existing HVAC equipment of commercial and residential prototype buildings used in this study (designed following the 2007 edition of ANSI/ASHRAE/IES Standard 90.1 for commercial buildings and the 2006 edition of IECC for residential buildings) (continued)

Building description	Total floor area (ft^2)	Heating equipment	Cooling equipment
Standalone retail	24,695	Gas furnace: 80% burner efficiency; standalone gas furnace for entrance: 80% burner efficiency	PTAC: EER 9.3–10.1; no cooling for entrance
Strip mall	22,500	Gas furnace: 80% burner efficiency	PTAC: EER 9.5–10.1; no cooling for entrance
Primary school	73,960	Gas furnace: 80% thermal efficiency; gas boiler: 80% thermal efficiency	PTAC: EER 9.3–10.1
Secondary school	210,900	Gas furnace: 80% thermal efficiency; gas boiler: 80% thermal efficiency	PTAC: EER 9.3; air-cooled chiller: 2.7 COP (1.3 kW/ton)
Outpatient healthcare	40,950	Gas boiler: 80% thermal efficiency	DX cooling: EER 9.3
Hospital	241,410	Gas boiler: 80% thermal efficiency	Water cooled chillers: 6.1 COP (0.6 kW/ton)
Small hotel	43,200	PTAC with electric resistance, gas furnace: 80% burner efficiency; electric cabinet heaters for storage and stairs	PTAC: EER 9.3–11; split system with DX cooling: SEER 13; no cooling for storage and stairs
Large hotel	122,132	Gas boiler: 80% thermal efficiency	Air-cooled chiller: 2.7 COP (1.3 kW/ton)
Warehouse	49,495	Gas furnace: 80% burner efficiency	PTAC: 9.5 EER; SEER 13
Quick service restaurant	2,500	Gas furnace: 80% burner efficiency	PTAC: EER 9.5–10.1
Full service restaurant	5,502	Gas furnace: 80% burner efficiency	PTAC: EER 9.3–10.1
Mid-rise apartment	33,700	Gas furnace: 80% burner efficiency	Split system DX: SEER 13
High-rise apartment	84,360	Water source heat pumps: Heating COP 4.2	Water source heat pumps: EER 11.2–12.0
Single-family home (SFH)	2,376	Gas furnace	Central air conditioner: SEER 13
SFH	2,376	Oil furnace	Split system DX: SEER 13
SFH	2,376	Heat pump	Split system DX: SEER 13
SFH	2,376	Electric resistance	Split system DX: SEER 13
Small multifamily housing	21,600	Gas furnace	Split system DX: SEER 13
Small multifamily housing	21,600	Oil furnace	Split system DX: SEER 13
Small multifamily housing	21,600	Heat pump	Split system DX: SEER 13
Small multifamily housing	21,600	Electric resistance	Split system DX: SEER 13

Table A-2. The 14 US climate zones included in this study, along with representative cities

Climate zone	Representative city
1A	Miami, Florida
2A	Houston, Texas
2B	Phoenix, Arizona
3A	Atlanta, Georgia
3B	Las Vegas, Nevada
3C	San Francisco, California
4A	Baltimore, Maryland
4B	Albuquerque, New Mexico
4C	Seattle, Washington
5A	Chicago, Illinois
5B	Boulder, Colorado
6A	Minneapolis–St. Paul, Minneapolis
6B	Helena, Montana
7A	Duluth, Minneapolis

APPENDIX B. PERFORMANCE CURVES AND FAN EFFICIENCIES OF GEOTHERMAL HEAT PUMPS

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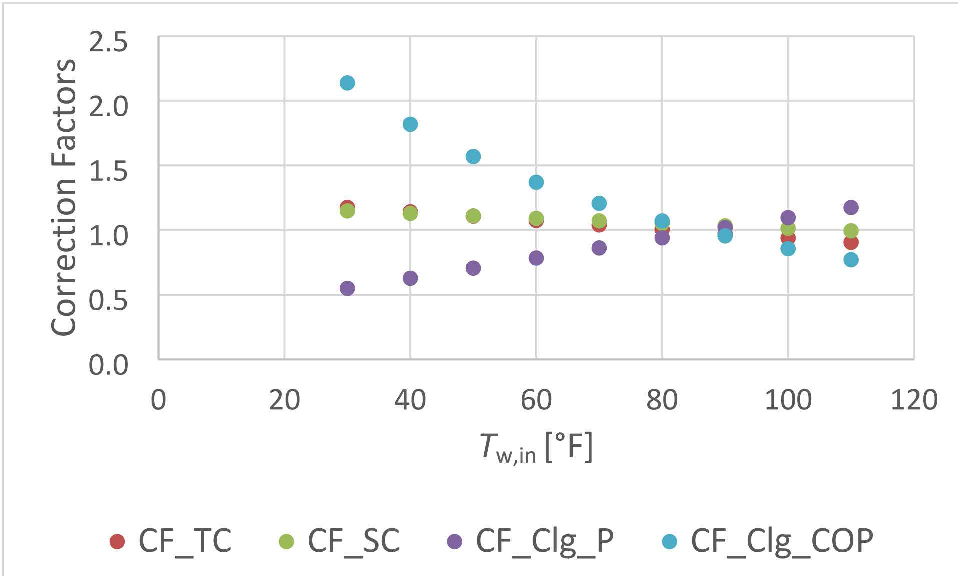


$T_{w,in}$: The temperature of water entering the source side of the geothermal heat pump (GHP)

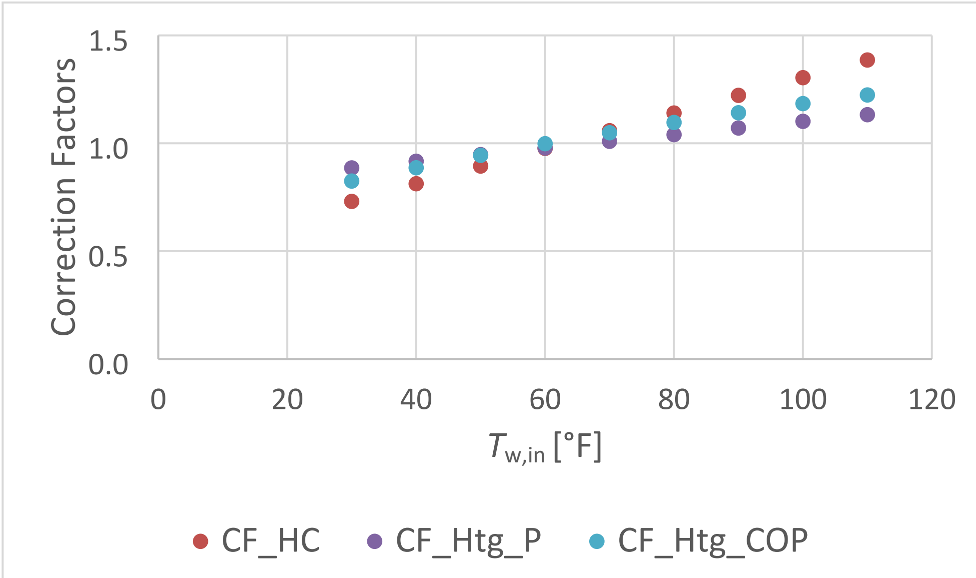
CF_TC: Correction factor for total cooling capacity, which is the ratio of the actual total cooling capacity to the nominal total cooling capacity at the rating condition

CF_SC: Correction factor for sensible cooling capacity, which is the ratio of the actual sensible cooling capacity to the nominal sensible cooling capacity at the rating condition

CF_Clg_P: Correction factor for cooling power consumption, which is the ratio of the actual power consumption to the nominal power consumption at the rating condition in cooling mode

CF_Clg_COP: Correction factor for cooling coefficient of performance (COP), which is the ratio of the actual COP to the nominal COP at the rating condition in cooling mode

Figure B-1. Performance curves of the GHPs in cooling mode.



$T_{w,in}$**:** The temperature of water entering the source side of the GHP

CF_HC: Correction factor for heating capacity, which is the ratio of the actual heating capacity to the nominal heating capacity at the rating condition

CF_Htg_P: Correction factor for heating power consumption, which is the ratio of the actual power consumption to the nominal power consumption at the rating condition in heating mode

CF_Htg_COP: Correction factor for heating COP, which is the ratio of the actual COP to the nominal COP at the rating condition in heating mode

Figure B-2. Performance curves of the GHPs in heating mode.

Table B-1. Efficiency and pressure rise of fans used in the modeled GHPs and the fans used in the existing HVAC systems of the prototype single-family homes

Variable	GHP fan	Existing fan
Motor efficiency	0.9	0.65
Fan total efficiency	0.7	0.38
Pressure rise (pa)	75	400

APPENDIX C. IMPACT ANALYSIS OF OUTDOOR AIR INFILTRATION ON HEATING AND COOLING LOADS OF SINGLE-FAMILY HOMES

APPENDIX C. IMPACT ANALYSIS OF OUTDOOR AIR INFILTRATION AND DUCTWORK LEAKAGE ON HEATING AND COOLING LOADS OF SINGLE-FAMILY HOMES

Outdoor air (OA) infiltration and ductwork leakage of an HVAC system significantly affects the heating and cooling demands of buildings, especially for single-family homes (SFHs). Depending on the climate and air tightness of a building envelope (e.g., exterior walls, ceilings, roofs, windows, and doors), the OA infiltration rates vary significantly from building to building. For SFHs in the United States, the majority of HVAC ductwork is installed in unconditioned attic space, where the air temperature is close to that of the outdoor ambient. Thus, air leakage and the associated energy loss from the ductwork could significantly increase the energy consumption for keeping the room temperature at desired set points.

To quantify the effects of OA infiltration and ductwork leakage on the heating and cooling energy consumption of SFHs, simulations were performed with the US Department of Energy's prototype SFH models across 16 climate zones (CZs) in the United States (Figure C-1). The prototype SFH models developed following the 2006 edition of the International Energy Conservation Code (IECC) were selected to represent existing SFHs. The 2006 edition of the IECC does not specify the minimum allowed OA infiltration rate and ductwork leakage. An airflow network was used in the prototype model to simulate the OA infiltration and ductwork leakage.[42] Four SFH models are in each CZ, and each has a different heating system, including an electric resistance heater, air-source heat pump, oil furnace, and gas furnace. The first set of 64 cases model OA infiltration and ductwork leakage using the airflow network implemented in the original prototype models. The second set of 64 cases eliminate OA infiltration and ductwork leakage by removing the airflow network.

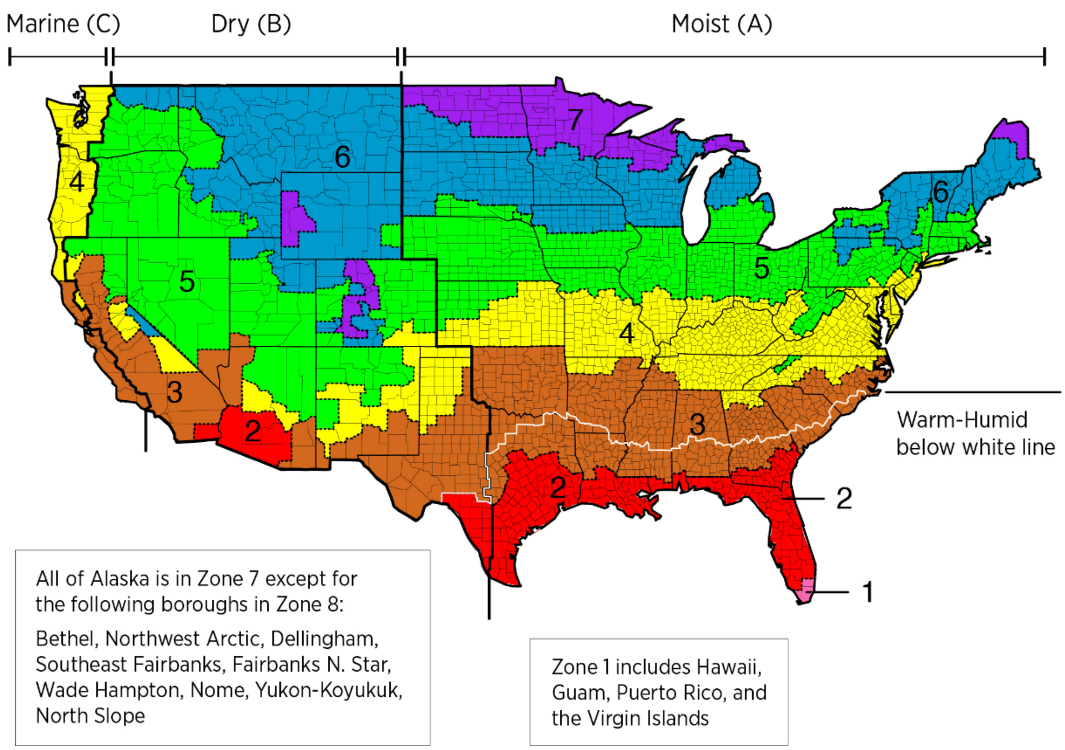


Figure C-1. CZ map for the United States. (Source: 2012 IECC, accessible at https://codes.iccsafe.org/content/IECC2012.)

[42] https://www.energycodes.gov/prototype-building-models

Figure C-2 shows the simulation results of the contribution of OA infiltration and ductwork leakage to the annual heating and cooling energy of the prototype SFHs at each CZ. The OA infiltration and ductwork leakage contribute 48% to 77% of the annual energy consumption for space heating. The contribution is higher in colder CZs because of the larger temperature difference between the ambient and the indoor air. For the annual space cooling energy consumption, the contribution ranges from −39% to 27%. The negative contributions are only for the three CZs (3C, 4C, and 5C) with marine weather, where the ambient temperature is mild and OA infiltration can cool the SFHs, thus reducing the cooling energy consumption. In terms of the annual heating and cooling energy consumption, the contribution of OA infiltration and ductwork leakage is between 21% and 71% for SFHs built following the 2006 edition of the IECC.

This analysis clearly indicates that OA infiltration and ductwork leakage contribute significantly to the annual heating and cooling energy consumption of SFHs, especially in cold climates. OA infiltration and ductwork leakage can be reduced by sealing the gaps, holes, and cracks in the ceilings, exterior walls, and ductwork, as well as applying weather strips to windows and doors.[43] According to previous studies, air sealing can reduce heating energy consumption by 30%–50% (Chan 2013, Hassouneh et al. 2012, Jokisalo et al. 2009, Lozinsky and Touchie 2018, Pasos et al. 2020, Sawyer 2014).

A case study for an SFH at CZ 5A indicates that the annual heating and cooling energy is reduced by 36% by delivering only the needed OA according to the 2007 edition of ASHRAE Standard 62.2 (ASHRAE 2007) with a dedicated outdoor air system (DOAS) instead of through the uncontrolled infiltration. Additionally, the required capacity of the geothermal heat pump (GHP) and the required size of the ground heat exchanger (GHE) are reduced by 30% and 16%, respectively. The reduced size of the GHP and GHE leads to a cost reduction, which may offset the expense for air sealing and the addition of a DOAS. Therefore, it is strongly recommended to include air sealing in a GHP retrofit because it can not only achieve deeper reduction in energy consumption and carbon emissions but also reduce the size and cost of GHP system. The reduced size of the GHP is critical in avoiding the winter peaking of electricity demand resulting from the electrification of space heating in buildings.

[43] https://sealed.com/resources/the-definitive-guide-to-air-sealing-your-house/

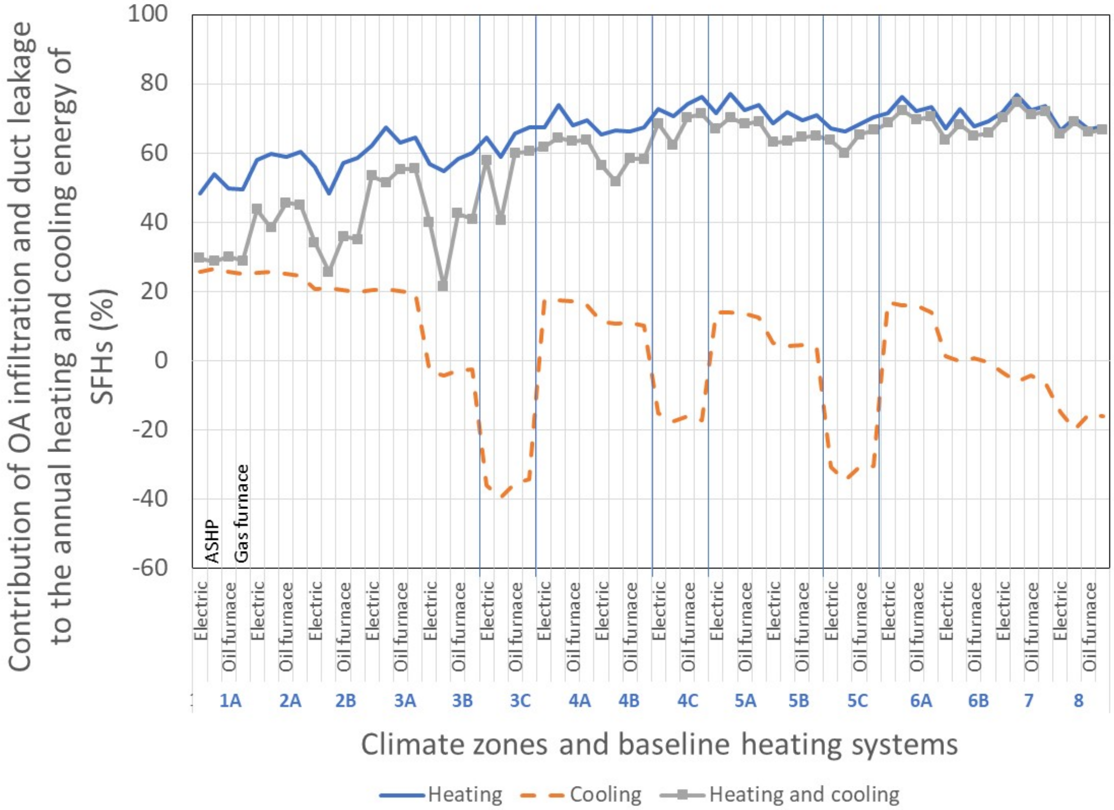


Figure C-2. Effects of OA infiltration and duct leakage on annual heating and cooling energy consumption of US Department of Energy prototype SFHs (designed following the 2006 edition of the IECC standard) at various CZs in the United States.

APPENDIX D. ADDITIONAL END-USE LOAD PROFILE DATA ANALYSIS

APPENDIX D. ADDITIONAL END-USE LOAD PROFILE DATA ANALYSIS

Table D-1. Characteristics of existing buildings included in NREL's end-use load profile database that are applicable for geothermal heat pumps (GHPs)

	Residential				Commercial			
	All	**GHP valid***	**With GHP system‡**	**%**	**All**	**GHP valid***	**With GHP system**	**%**
Number of housing units (10^6)	133.124	102.18	—	76.8	—	—	—	—
Floor space (10^6 ft^2)	234,458	185,937	—	79.3	54,942	41,908	1,059	76.3♦
Heating energy use (10^6 kWh) †	1,817,080	1,436,900	—	79.1	208,642	193,227	1,090	92.6♦
Cooling energy use (10^6 kWh) †	269,681	247,583	—	91.8	114,588	89,242	2,914	77.9♦

*Residential buildings that are applicable for GHP retrofit (excluding mobile homes, heating fuel none/other, cooling none); commercial buildings that are applicable for GHP retrofit (excluding district heating and/or cooling systems, GHP system, heating none, cooling none/evaporative)

♦ it is the percentage of commercial buildings that are included in NREL's end-use load profile database, which only accounts for 64% of existing commercial buildings in the US.

†Fan and pump energy excluded

‡No indication provided for residential buildings that already use a GHP

APPENDIX E. RELIABILITY ANALYSIS METHOD

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The calculated electricity demand with the geothermal heat pump (GHP) retrofit in 2021 was obtained by first calculating the demand reduction owing to the retrofit in 2021, and then subtracting it from the anticipated electricity demand in 2021. Because the end-use load profile data set does not include 2021 energy consumption data of individual balancing areas (BAs), researchers have proposed to calculate the demand reduction with the GHP retrofit based on available data in 2018 first, then forecasting the demand reduction of individual BAs in 2021 using a machine learning approach referred to as multilayer perceptron (MLP) (Suter 1990).

The detailed procedures of using MLP for forecasting the demand reduction in 2021 are as follows.

1. For the year of 2018, determine the ratios of the total building demand for individual BAs within the Electric Reliability Council of Texas (ERCOT). The *building demand ratio* is defined as the total building demand of a given BA to the total building demand of the ERCOT. Notably, the building demand accounts for most of the total demand in each BA. Without additional information on the nonbuilding demand of each BA, the building demand ratio is assumed to represent the ratio of the total demand of each BA to the total demand of the ERCOT.
2. Multiply the building demand ratio by the total demand of the ERCOT in 2018 to determine the total demand of each BA in 2018.
3. Determine the ratios of daily demand reduction for individual BAs in 2018. The daily demand reduction ratio is defined as the daily demand reduction of a given BA to the total daily demand of the same BA. The daily demand reduction is obtained by summing the hourly reduction, which can be obtained by the methodology described in Section 3.
4. Train the MLP by using the daily demand reduction ratios and weather conditions in 2018. Commonly considered weather conditions include average temperature, dew point, humidity, wind speed, and atmospheric pressure.
5. Apply the trained MLP to forecast the daily demand reduction ratio of each BA in 2021 with the weather conditions in 2021.
6. Determine the total demand of each BA in 2021 based on the building demand ratios in 2018 and the anticipated demand of ERCOT in 2021.
7. Multiply the forecasted daily reduction ratio by the total daily demand of each BA to determine the daily demand reduction of each BA in 2021.
8. Determine the total daily demand reduction of the ERCOT by summing the forecasted daily demand reduction of individual BAs.
9. Distribute the daily demand reduction of the ERCOT to each hour based on the ratio of hourly demand to the total daily demand of the same day.

In these steps, weather conditions are used as inputs for the MLP model because of their substantial effect on the electricity consumption of buildings. Cold and hot weather conditions necessitate the operation of heating and cooling systems, respectively, which contribute significantly to the overall electricity consumption of buildings. The correlation matrix between the average temperature and daily building electricity demand can be calculated based on the temperature data and electricity consumption data in 2018.