Supplemental Information

Probabilistic analysis of ecological, economic, and health tradeoffs of decarbonization pathways for New England, USA

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1. Decarbonization pathways and scheduling of new generation and retirements

We model pathways already proposed and evaluated by ISO-NE in order to (1) validate our methodology by comparing select endpoints shared between this analysis and analysis previously undertaken by ISO-NE and (2) provide more detailed information on the spatial and temporal distribution of costs and benefits for pathways already known to be of interest. This includes pathways A, B1, B2 and B3. We also model pathways not previously considered by ISO-NE but of interest to local stakeholders and/or the research community. This includes pathways C1, C2, C3 and D, including build-out of small modular nuclear reactors. As described in the main text, the model does not optimize a portfolio based on an objective function but calculates the direct and indirect cost tradeoffs associated with prescribed pathways.

Pathway A represents "status quo" where no new generation or transmission assets are built and demand is satisfied by dispatching existing resources. No generators are retired over the period of analysis. Pathways B1, B2, and B3 were proposed by ISO-NE as alternative pathways based on increased intertie capacity with Canada (constrained in B2) and increased offshore wind (constrained in B3). ISO-NE considers that new construction of hydroelectric generation capacity in Quebec (on the order of ~9 GW, according to recent estimates by ISO-NE) would be necessary to provide the level of exports in B3 (Commonwealth of Massachusetts, 2020). The ~9 GW build-out aligns with Hydro-Québec's stated potential and provides a plausible high-capacity benchmark for intertie feasibility.

Table S1: Build-out/retirement by 2050 of technologies under each decarbonization pathway (yearly schedule provided in Supplemental Information (SI) Table S2).

Technology	Pathway							
	A	B1	B2	B3	C1	C2	C3	D
New interties with Quebec	None	+4.1 GW	None	+6 GW	None	None	+4.1 GW	+4.1 GW
New hydropower reservoirs in Quebec	None	None	None	~9 GW reservoir	None	None	None	None
New offshore wind	None	+33 GW	As required to balance 10 GW growth in demand by 2050 (>41 GW)	+28.5 GW	None	+33 GW	+28.5 GW	+1.5 GW
New small modular reactors	None	None	None	None	+42 GW	+4.2 GW	+2.1 GW	None
New natural gas power plants	None	None	None	None	None	None	None	+20 GW
Forced coal retirements	None	All retired by 2030	All retired by 2030	All retired by 2030	All retired by 2030	All retired by 2030	All retired by 2030	None
New solar	None	+64 GW	+64 GW	+64 GW	None	+64 GW	+64 GW	+ 14 GW
New onshore wind	None	+12 GW	+12 GW	+12 GW	None	+12 GW	+12 GW	+ 5 GW
Battery storage	None	+16.4 GW	+16.4 GW	+16.4 GW	None	+16.4 GW	+16.4 GW	+16.4 GW

All these pathways represent plausible bounds of alternative futures rather than forecasts.

Pathways C1, C2, and C3 are based on deployment of small modular nuclear reactors (SMRs), a pathway not currently envisioned by ISO-NE but of increasing interest to the public, advocacy organizations, policymakers, and other stakeholders. Recent developments such as partial reactivation of Three Mile Island in Pennsylvania to supply energy for a Microsoft data center and interest by other companies such as Amazon and OpenAI point to a likely future for SMRs, but these are not widely considered in other studies or in state/utility energy plans (Bowman, 2024; Castelvecchi, 2024; Gazar, 2023; L'Her et al., 2024; Vanatta et al., 2024). Scheduling of new generators is described below.

Pathway D considers construction of new natural gas plants and is not a pathway retained by ISO-NE but may nonetheless be plausible under certain changes in energy policy, for example, rescission or expiry of credits or incentives under the Inflation Reduction Act (Gerrard, 2024; Osaka, 2024; U.S. EIA AEO, 2023). We assume the following capacity build-up for this pathway includes 1.5 GW offshore wind, 5 GW onshore wind and 14 GW of solar PV. This pathway assumes addition of 20 GW of natural gas capacity with technical specifications drawn from CPV Towantic Energy Center combined cycle power plant located in Oxford, CT (nameplate capacity 565.5 MW), the most recently (operating started in 2018) constructed natural gas facility in New England.

Across all pathways, we assume that existing large nuclear power plants and natural gas plants will be maintained through 2050. Pathways A and D have no retirements, following the U.S. EIA "No IRA [Inflation Reduction Act] Scenario". Details from this U.S. EIA scenario are included in SI Table S2.

The magnitudes and locations of new onshore wind, offshore wind, and solar capacity were derived from ISO-NE resource-adequacy studies and constrained to realistic coastal and inland siting densities. Offshore capacity was distributed by ISO-NE among federally leased areas off Massachusetts, Rhode Island, and Maine, whereas onshore wind and solar additions were allocated according to land availability and historical project density.

Pathways other than A and D consider likely retirements of existing generators over the period 2025 to 2050, including those already scheduled. This includes a complete phase-out of coal-fired power plants and the retirement of 75% of conventional oil-fired units, including dual-fuel facilities. This corresponds to the schedule established in ISO-NE's modeling assumptions in (Commonwealth of Massachusetts, 2020).

We considered that 75% of oil-fired units (5,250 MW) would be retired by 2030 (Commonwealth of Massachusetts, 2020) by filtering facilities using oil as their primary fuel type, calculating the 75th percentile of their real average capacity factor, identifying those at or below that threshold, and assigning them a 2030 retirement date, thereby ensuring less-utilized (higher marginal cost) facilities are retired first.

Additionally, plants are retired when they reach the end of their economic lifetime: 75 years for coal-fired plants, 45 years for wood-fired plants, and 55 years for other fossil fuel plants based on NREL's end of lifetime estimates for these plants (NREL, 2024). These ages are calculated based on data reported to the United States Environmental Protection Agency (U.S. EPA) Emissions & Generation Resource Integrated (eGRID) database and to the U.S. Energy Information Agency (EIA) via U.S. EIA Form 860 (U.S. EIA 860, 2023; U.S. EPA eGrid, 2022). Facility specific retirement details are included in SI Table S3.

2. Model formulation

2.1. Notation

2.1.1. *Sets and indices*

$t \in \mathcal{T}$: hours

$g \in \mathcal{G} = \{\text{Solar}, \text{Wind}_{\text{onshore}}, \text{Wind}_{\text{offshore}}, \text{Nuclear}, \text{Hydro}, \text{Biomass}, \text{SMR}, \text{Fossil}\}$

$u \in \mathcal{U}$: fossil fuel-based generating units

$j \in \mathcal{J} = \{\text{HQ}, \text{NYISO}, \text{NBSO}\}$: interties to neighboring regions

$\omega \in \Omega$: Monte Carlo draw

$y \in Y$: year between 2025 and 2050 (for Social Cost of Carbon schedule)

$s \in S$: pathways

2.1.2. *Parameters*

D_t: demand (MWh)

$\text{Cap}_{g,t}$: installed capacity (MW)

$\text{CF}_{g,t}(\omega) \in [0,1]$: capacity factor (percentile mapped to historical variable hourly capacity factors)

$\text{Cap}_{j,t}^{\text{LT}}, \text{Cap}_{j,t}^{\text{spot}}$: import capacities for long-term contracts (LT) and spot-market (spot) (MW)

$\bar{I}_t$: imports ceiling (MWh)

$\eta \in (0,1)$: one-way efficiency

$\rho \in (0,1]$: hourly retention factor

$E_{\max,t}$: storage energy cap (MWh)

$P_{\max,t}$: storage inverter or power cap (MW)

$\underline{P}_u, \bar{P}_u$: unit min and max generation capacity (MW)

$\bar{R}_u$: ramp limit (maximum generation dispatch limit (MWh))

$\chi_{u,t} \in \{0,1\}$: availability or retirement

κ_j: import price (USD/MWh)

f_u, v_g: fuel and VOM rates (USD/MWh)

$s_{k,y}^{\text{GHG}}$: social cost for GHG $k \in \{\text{CO}_2, \text{CH}_4, \text{N}_2\text{O}\}$ in year y $(2024 - USD\ per\ tonne)$

$\hat{v}^k$: damage factor for pollutant $k \in \{\text{CO}, \text{NO}_2, \text{SO}_2, \text{PM}_{2.5}, \text{PM}_{10}, \text{VOC}\}$ $(2024 - USD\ per\ tonne)$

π_{short}: value of lost load (USD/MWh)

r, y_0: discount rate, base year

2.1.3. *State and decision variables*

$G_{g,t} \geq 0$: non fossil generation (MWh)

$G_{u,t} \geq 0$: fossil unit generation (MWh)

$I_{j,t}^{\text{LT}}, I_{j,t}^{\text{spot}} \geq 0$: imports (MWh)

$\text{SOC}_t \in [0, E_{\max,t}]$: state of charge (MWh)

$c_t, d_t \geq 0$: charge and discharge (MWh)

$\text{Curt}_t, \text{Short}_t \geq 0$: curtailment and shortage (MWh)

2.2. Demand

Hourly demand forecasts for New England were obtained from the Commonwealth of Massachusetts via request under the Massachusetts Public Records Act. These data support the publicly available decarbonization roadmap (Commonwealth of Massachusetts, 2020) and correspond to the ISO-NE 2025-2050 “High Electrification” pathway. This pathway assumes a medium level of flexibility in end-use loads, including incentivized consumer behavior to reduce consumption during peak demand (e.g., 53,715 MW on January 24th, 2050 and total demand in 2050 of 203 TWh). Raw data for all demand pathways are provided in the SI to allow for reanalysis under alternative forecasts.

We implement a load duration curve approach utilizing the full hourly demand profile, totaling 227,880 timesteps for the period from 2025 to 2050, consistent with the methodology used by other recent energy models (Dagoumas & Koltsaklis, 2019). The model can also be run using less computationally demanding representative demand curves or individual time slices if required.

2.3. Low-carbon generation

Low-carbon energy sources are dispatched first to satisfy hourly demand as a function of installed capacity and capacity factor (either deterministic or drawn from a probability distribution $(\omega \in \Omega)$). The distribution is jointly distributed for solar and onshore and offshore wind as described in SI Section 2.3.1 and independent for others. Generally, hourly renewable generation at timestep t (G_t) is the sum of installed capacity (Cap) multiplied by capacity factors (CF) for each low-carbon technology. Low-carbon technologies $(\mathcal{G}\{\text{lowcarbon}\})$ are solar, onshore wind $(\text{wind}_{\text{on}})$, offshore wind $(\text{wind}_{\text{off}})$, nuclear, hydropower, biomass, and small modular nuclear (SMR). This is formalized in Equations 1 to 8.

$$G_t^{\text{lowcarbon}} \equiv \sum_{g \in \mathcal{G}\{\text{lowcarbon}\}} G_{g,t} \qquad Eq.1$$

$$G_{\text{Solar},t} = \text{Cap}_{\text{Solar},t}\ \text{CF}_{\text{Solar},t}(\omega) \qquad Eq.2$$

$$G_{\text{Wind}_{\text{on}},t} = \text{Cap}_{\text{Wind}_{\text{on}},t}\ \text{CF}_{\text{Wind}_{\text{on}},t}(\omega) \qquad Eq.3$$

$$G_{\text{Wind}_{\text{off}},t} = \text{Cap}_{\text{Wind}_{\text{off}},t}\ \text{CF}_{\text{Wind}_{\text{off}},t}(\omega) \qquad Eq.4$$

$$G_{\text{Nuclear},t} = \text{Cap}_{\text{Nuclear},t}\ \text{CF}_{\text{Nuclear}} \qquad Eq.5$$

$$G_{\text{Hydro},t} = \text{Cap}_{\text{Hydro},t}\ \text{CF}_{\text{Hydro}} \qquad Eq.6$$

$$G_{\text{Biomass},t} = \text{Cap}_{\text{Biomass},t}\ \text{CF}_{\text{Biomass}} \qquad Eq.7$$

$$G_{\text{SMR},t} = \text{Cap}_{\text{SMR},t}\ \text{CF}_{\text{SMR}} \qquad Eq.8$$

In hours where demand can be satisfied with available low-carbon sources and/or required ramping of fossil fuels to meet future demand (SI Section 2.6), excess energy is used to charge batteries within technical constraints (SI Section 2.4). If this is inadequate to dissipate excess energy, then wind and solar are curtailed. Considering no meaningful historical exports out of New England is recorded we do not consider exports to other jurisdictions in the future as part of this model. However, in order to consider such exports can be) considered as sold to other jurisdictions within historical constraints by assigning a negative value to imports.

2.3.1. *Wind and solar generation*

Contribution of wind (onshore and offshore) and solar resources is determined by multiplying installed capacity (increasing between 2025 and 2050 according to the Pathway retained as described in SI Section 1) by a capacity factor. Capacity factors are described by probability distributions specific to each hour within a calendar year and are calculated using simulated capacity factors supplied by ISO-NE (ISO-NE, 2024a) as described in more detail in our methods on Monte Carlo simulation (SI Section 3).

Wind and solar correlations across weather years are maintained through covariance-based sampling of probability distributions (SI Section 3). Capacity-factor distributions are location-specific for wind and solar but uniform for hydropower (SI Table S9) given limited intra-annual variability across ISO-NE facilities.

2.3.2. *Nuclear, domestic hydropower, and biomass generation*

Data from the National Renewable Energy Laboratory's Annual Technology Baseline (NREL ATB) 2024 are used to derive deterministic capacity factors for large nuclear (0.93), domestic hydropower (0.56), and biomass (0.60) generators (NREL, 2024). These are dispatched following wind and solar due to low marginal cost at timesteps where renewables alone cannot satisfy demand (Commonwealth of Massachusetts, 2020). Similarly, we selected the 300 MWe SMR with capacity factor of 0.9 since this is currently the only SMR in the NREL portfolio projected to be available from 2030 (NREL, 2024).

Across pathways, existing large nuclear generation accounts for 27.29 TWh per year by 2050 (13% of annual demand), domestic hydropower accounts for 4.42 TWh (2% of demand), and biomass accounts for 2.10 TWh (1.03% of demand). In pathways C1, C2, and C3, investments in SMRs lead to potential maximum generation of 331.12 TWh, 33.11 TWh, and 16.56 TWh per year (representing 163%, 16%, and 8% of annual demand) by 2050, respectively.

2.4. Commercial battery storage

We model battery storage with symmetric charge and discharge efficiencies of 92% in each direction, yielding an 85% round-trip efficiency, meaning that 85% of the input energy is effectively stored and later available for use (NREL, 2024). State-of-charge dynamics follow this formulation, ensuring that energy accounting correctly represents storage losses. Discharge occurs only when renewable generation plus imports are insufficient to meet demand, and simultaneous charge–discharge is disallowed (NREL, 2024). We model the operation of commercial lithium-ion battery storage systems by utilizing surplus generation to charge the batteries during timesteps when generation exceeds demand. This occurs at hours when demand is exceeded by the supply of low-carbon energies and/or fossil fuel sources ramping upward to meet future demand. Conversely, batteries are discharged during timesteps when renewable generation and imports are insufficient to meet demand.

To determine the maximum charge and discharge rates, we adopt an inverter-to-storage ratio of 1.67 (i.e., fast charging and discharging), as recommended by the NREL in the 2024 ATB (NREL, 2024). Long-duration energy storage (LDES) is represented with an explicit duration parameter (default = 8 hours) that can be extended by pathway flag. Unlike short-duration systems, LDES may not fully cycle each day; state-of-charge retention between cycles is modeled via an efficiency-weighted persistence term. This captures dispatch flexibility without making duration a decision variable.

2.4.1. *Power cap from inverter and duration*

Storage dispatch is bounded by a power limit derived from the installed energy capacity and the chosen duration, as well as by the installed inverter capacity. Let nameplate energy capacity at time t be $E_{\max,t} \equiv \mathrm{Cap}_t^{stor}$(MWh) and duration be H^{dur}(h). The maximum charge or discharge power is therefore the minimum of the duration-implied power rating and the inverter limit:

$$P_{\max,t} = \min\{\frac{E_{\max,t}}{H^{\mathrm{dur}}}, \mathrm{Inv}_t\}, P_{\max,t} \geq 0 \qquad Eq.9$$

2.4.2. *State update with retention and symmetric round trip*

Battery state of charge (SOC) evolves according to one-way efficiency, hourly retention, and physical bounds. Let η_{rt} denote round-trip efficiency and $\eta = \sqrt{\eta_{rt}}$ the symmetric one-way efficiency. Let ρ denote the hourly retention factor. Then SOC at time $t$is updated from $t-1$ as:

$$\mathrm{SOC}_t = \min\{\max(\rho\, \mathrm{SOC}_{t-1} + \eta\, c_t - \frac{1}{\eta} d_t, 0), E_{\max,t}\} \qquad Eq.10$$

Charging and discharging power are bounded by the power cap:

$$0 \leq c_t \leq P_{\max,t}, 0 \leq d_t \leq P_{\max,t}$$

Curtailment-only charging guard (battery may only charge from otherwise excess low-carbon supply):

$$c_t \leq \max(0, G_t^{\text{low carbon}} + I_t - D_t)$$

Note on battery daily reset (optional). If multi day carry is disabled, set $\mathrm{SOC}_t \leftarrow 0$ at local midnight before applying retention.

We also define the modeled SOC change attributable to charging and discharging as:

$$\Delta_t^{\mathrm{bat}} = \eta\, c_t - \frac{1}{\eta} d_t \qquad Eq.11$$

2.5. Imports from other jurisdictions

ISO-NE imports energy from Hydro-Québec, New York ISO, and the New Brunswick System Operator (NBSO). Decarbonization pathways B1, B3, C3 consider increased imports from Quebec with (B3) or without (B1 and C3) expanded generation in Quebec. Recently negotiated import agreements between Quebec and New York/Massachusetts commit to a constant transmission schedule with fixed prices for a period of approximately 20–25 years (see NECEC's 20-year fixed-price contracts (Central Maine Power Company, 2019; Hamlen & Lenzen, 2024) and CHPE's 25-year benefit framework (CHPExpress, 2021; Naldal, 2022)). Once agreed, the marginal price of these imports is zero, and so the model dispatches these resources ahead of fossil fuels. In these pathways, long-term contracts are to account for the all-new imports, therefore subject to a fixed capacity factor. We assume all new imports from Quebec under all pathways are under a fixed-price contract.

For other imports negotiated on the short-term spot market with variable costs, we use historical data for the period 2011 to 2023 to simulate hourly transmission and prices. We calculate historical variable hourly capacity factors by dividing real imports by available transmission capacity and apply that to the available transmission capacity available in the period 2025–2050. Transmission capacity for spot-market imports (unlike for long-term contractual imports as described above) is held constant for pathways A, B1-3, C1-3 and D. Historical data are used to develop prior distributions, which are randomly sampled. In the event that fossil fuel generation (SI Section 2.6) when added to the other available capacity is not adequate to satisfy hourly demand, spot market imports are resampled to select the value that will satisfy demand (within the constraints of historical maxima). If available fossil fuel resources (SI Section 2.6) and import capacity, when combined with other sources, cannot satisfy hourly demand, then an unmet demand penalty is applied (SI Section 2.7). Posterior distributions are saved and analyzed.

For Pathways B1, C3, and D, investments in transborder infrastructure lead to average imports up to 60.54 TWh per year (30% of annual demand) by 2050, respectively. For Pathway B3 these investments lead to average imports up to 76.35 TWh (38% of annual demand). For other Pathways (including "status quo" Pathway A), average imports from other jurisdictions account for 26.42 TWh per year (13% of annual demand).

Let $\bar{CF}^{imp} = 0.95$ denote the maximum import capacity factor. Eq. 12 defines long-term contractual imports $I^{LT}_{(j,t)}$ from jurisdiction j at time t as a fixed fraction of available long-term transmission capacity $\mathrm{Cap}^{LT}_{(j,t)}$, reflecting constant schedules under fixed-price agreements. Eq. 13 bounds spot-market imports $I^{spot}_{(j,t)}$ by available spot-market transmission capacity $\mathrm{Cap}^{spot}_{(j,t)}$ and a stochastic capacity factor $CF^{spot}_{(j,t)}(\omega)$ drawn from historical data. Eq. 14 defines total imports I_t as the sum of long-term and spot-market imports across all jurisdictions. Finally, Eq. 15 imposes a system-wide upper bound on total imports $\bar{I}_t$, determined by aggregate transmission capacity and the maximum import capacity factor $\bar{CF}^{imp}$.

$$\boldsymbol{I^{\mathrm{LT}}_{j,t} = \mathrm{Cap}^{\mathrm{LT}}_{j,t} \,.\, \bar{\mathrm{CF}}^{\mathrm{imp}}} \qquad \boldsymbol{Eq.12}$$

$$\boldsymbol{0 \leq I^{\mathrm{spot}}_{j,t}} \leq \mathrm{Cap}^{\mathrm{spot}}_{j,t}\, \mathrm{CF}^{\mathrm{spot}}_{j,t}(\omega) \qquad Eq.13$$

$$\boldsymbol{I_t} = \sum_j \left(I^{\mathrm{LT}}_{j,t} + I^{\mathrm{spot}}_{j,t}\right) \qquad Eq.14$$

$$\boldsymbol{I_t \leq \bar{I}_t} = \bar{\mathrm{CF}}^{\mathrm{imp}} \sum_j \left(\mathrm{Cap}^{\mathrm{LT}}_{j,t} + \mathrm{Cap}^{\mathrm{spot}}_{j,t}\right) \qquad Eq.15$$

2.5.1. *Imports netting logic (headroom allocation)*

Eq. 14 defines net imports I^{net}_t prior to calibration. When a system shortfall $\mathrm{Short}_t > 0$ exists, imports are increased up to the remaining import headroom $\bar{I}_t - I_t$; otherwise, imports are limited to the minimum required to meet residual demand after low-carbon generation, other generation $G_{(u,t)}$, and battery discharge d_t. In the calibration pass, any additional imports required ΔI_t are allocated across interties based on available headroom, which is defined as unused import capability up to the maximum allowable capacity factor. Eq. 15 and Eq. 16 define long-term and spot-market headroom $H^{LT}_{(j,t)}$ and $H^{spot}_{(j,t)}$ as the difference between maximum feasible imports and realized imports on each intertie. Eq. 17 and Eq. 18 allocate ΔI_t sequentially to Hydro-Québec long-term and then spot-market imports, reducing the remaining requirement after each step. Eq. 19 enforces zero spot-market headroom for NYISO and NBSO under the assumed import structure.

Before calibration:

$$\boldsymbol{I_t^{\mathrm{net}}} = \begin{cases} \boldsymbol{I_t + \min\left(\mathrm{Short}_t, \bar{I}_t - I_t\right), \ \mathrm{Short}_t > 0} \\ \boldsymbol{\min\left\{I_t, max\left(0, D_t - \left(G_t^{low\ carbon} + \sum_u G_{u,t} + d_t\right)\right)\right\}, \quad \mathrm{Short}_t = 0} \end{cases} \qquad \boldsymbol{Eq.14}$$

In the calibration pass, any extra imports required $\Delta I_t = \max\left(0, I_t^{\mathrm{net,cal}} - I_t\right)$ are allocated to interties by available headroom to the max CF:

$$\boldsymbol{H^{LT}_{j,t} = Cap^{LT}_{j,t}\ \bar{C}F^{imp} - I^{LT}_{j,t}} \qquad \boldsymbol{Eq.15}$$

$$H^{spot}_{j,t} = Cap^{spot}_{j}\ CF^{spot}_{j,t}(\omega) - I^{spot}_{j,t} \qquad Eq.16$$

Then sequentially (LT then spot; then HQ):

$$\boldsymbol{\Delta I^{LT}_{HQ,t} = \min\left(\Delta I_t, H^{LT}_{HQ,t}\right), \Delta I_t \leftarrow \Delta I_t - \Delta I^{LT}_{HQ,t}} \qquad \boldsymbol{Eq.17}$$

$$\Delta I^{spot}_{HQ,t} = \min\left(\Delta I_t, H^{spot}_{HQ,t}\right), \Delta I_t \leftarrow \Delta I_t - \Delta I^{spot}_{HQ,t} \qquad Eq.18$$

NYISO and NBSO do not have spot CF under our assumptions:

$$\boldsymbol{H^{spot}_{NYISO,t} = H^{spot}_{NBSO,t} = 0} \qquad \boldsymbol{Eq.19}$$

2.6. Fossil fuel generation

The difference between hourly demand (SI Section 2.2) and generation from wind and solar (SI Section 2.3.1), domestic hydropower, nuclear, and biomass (SI Section 2.3.2), battery discharges (SI Section 2.4), and imports from neighboring jurisdictions (SI Section 2.5) is accounted for by fossil fuel generation. The importance of potential fossil fuel generation by 2050 depends on the pathway considered as described in SI Section 1 and is as high as 107.6 TWh (representing 53% of annual demand) for pathways A and D and as low as 73.7 TWh (representing 36.2% of annual demand) for all other pathways. Additionally, in pathway D the potential generation of newly built natural gas plants accounts for 151.6 TWh (74.6% of the annual demand) by 2050.

The hourly fossil fuel demand in a given timestep is the sum of (1) demand unmet by renewables and other low-marginal-cost generation and imports described above and (2) increased generation necessary to respect ramping constraints to meet future demand. Ramping is carried out in accordance with each generating unit's ramping constraints. Each unit maintains a minimum generation level at all times, from which it ramps up as needed when demand increases. By using the look-ahead approach, if an upcoming demand is observed, we begin ramping sooner so the unit can reach maximum capacity precisely when the peak occurs.

Excess energy produced in ramping hours is balanced by (1) charging batteries (if available), (2) and, (2) curtailing wind and solar for that hour if (1) is not sufficient to dissipate excess energy.

We developed a database of 4,633 generating units at 1,379 electric utility generating facilities across the United States cross-referenced to hourly generation and CO_2, NO_x, and SO_2 emissions data for the period from 2013 to 2023, inclusively, from the U.S. EPA Clean Air Markets Program Data (CAMPD) API (U.S. EPA 2024). Emissions of CO, N_2O, PM_{10}, $PM_{2.5}$, and VOC are determined by technology-specific emissions factors tabulated in SI Table S6. For all generating units and all generation and emissions variables, synthetic hourly probability distributions were fitted to the data for the period 2011 to 2023 to calculate 1st to 99th percentiles to be stochastically sampled (or run deterministically at the 50th percentile). Hourly generation in New England is cross-referenced with nameplate capacities from the EPA's CAMPD, and if the resulting capacity factor exceeds 1 (indicating a misreported capacity), we correct it using EIA 860 or eGrid data (U.S. EIA 860, 2023; U.S. EPA CAMPD, 2024; U.S. EPA eGrid, 2022). This has been completed for all generators in the database across all regions of the U.S. All relevant data has been archived in storage managed by Virginia Tech ARC and is accessible via the supplemental information.

In New England, approximately 7% of generating units accounting for 1.81% of all installed capacity were not represented in the CAMPD database we used to develop hourly generation and emissions distributions. For these facilities, distributions were developed by pooling units of the same technology and, where nameplate capacity was reported, of the same nameplate capacity range (± 20 MW). Technology groups were defined as combinations of unit types (e.g., "boiler", "combined cycle"), and primary fuel type (e.g., "coal"," natural gas"). This approach was also used to fill in emissions factors for CO_2, NO_x and SO_2 (3.24%, 1.81% and 8.98% of all installed capacity in New England respectively).

Hour-specific historical generation data is evaluated to ensure that it is mathematically possible to satisfy demand at a given timestep within historical maxima for that hour. Ensuring that historical maxima are not exceeded ensures that the model implicitly captures constraints such as within-grid bottlenecks or other technical constraints not explicitly modeled. If available fossil fuel resources cannot satisfy demand at a given timestep when added to previously sampled sources, then all generators are assigned generation corresponding to the historical maximum for the corresponding hour, and batteries are discharged subject to the discharge constraint. If these are not sufficient to meet demand, then imports from other jurisdictions (SI Section 2.5) are resampled (after verification that historical hourly maximum, when added to allocated generation and battery discharge, will satisfy demand). If historical hourly maximum fossil fuel generation and imports, when added to maximum battery discharge and available renewable supply, is insufficient to meet demand, then imports are also assigned the maximum historical hour-specific value, and an unmet demand penalty is applied (SI Section 2.7). Posterior distributions for all generation (and imports) are saved.

2.6.1. *System level fossil requirement (aggregate, pre unit-level dispatch)*

Eq. 20 and Eq. 21 define the system-level fossil fuel requirement prior to unit-level dispatch. Eq. 20 defines residual fossil demand R_t^{fos} as unmet hourly demand after accounting for low-carbon generation $G_t^{lowcarbon}$, imports I_t, and battery discharge d_t. Eq. 21 constrains aggregate fossil generation across all fossil units $u \in U$ to be nonnegative and bounded by the minimum of this residual requirement and an exogenous hourly fossil envelope $\bar{F}_t$, which reflects legacy fleet availability derived from historical maximum–minimum fossil generation profiles with pathway-specific retirements.

$$\boldsymbol{R_t^{\text{fos}}} = \mathbf{max}\,\{\mathbf{0}, \boldsymbol{D_t} - \boldsymbol{G_t^{\text{low carbon}}} - \boldsymbol{I_t} - \boldsymbol{d_t}\} \qquad \boldsymbol{Eq.20}$$

$$0 \leq \sum_{u \in \mathcal{U}} G_{u,t} \leq \min\,\{\bar{F}_t, R_t^{\text{fos}}\} \qquad Eq.21$$

For pathways without fossil retirements (Pathways A and D), the hourly fossil envelope $\bar{F}_t$is set equal to the historical hour-specific maximum fossil generation without retirements. For all other pathways, $\bar{F}_t$ reflects pathway-specific retirements and is derived from historical hour-specific maximum fossil generation with retirements.

2.6.2. *Per unit constraints and ramping (two pass adjustment)*

Eq. 22 enforces unit availability and nameplate capacity limits, where $\chi_{(u,t)} \in \{0,1\}$ is an availability indicator, $\bar{P}_u$ is the minimum stable output, and $\bar{P}_u$ is the maximum capacity; when $\chi_{(u,t)} = 0$, generation is zero. After initial hourly generation draws $G^{\star}_{(u,t)}$, ramping constraints are enforced using a two-pass adjustment with hourly ramp budget $\bar{R}_u$. In the backward pass (Eq. 23), generation at $t-1$ is increased if necessary so that the change to t does not exceed $\bar{R}_u$. In the forward pass (Eq. 24), generation at t is adjusted relative to $t-1$ to prevent infeasible downward ramps. Finally, Eq. 25 applies minimum output constraints by setting adjusted generation $G^{adj}_{(u,t)}$to at least the unit's minimum stable output $\bar{P}_u$, ensuring unit-level feasibility while preserving the sampled profile as closely as possible.

$$\boldsymbol{\chi_{u,t}\, \underline{P}_u \leq G_{u,t} \leq \chi_{u,t}\, \bar{P}_u} \qquad \boldsymbol{Eq.22}$$

The hourly ramp budget is defined as $\bar{R}_u$ (MWh per hour). The algorithm enforces, after initial sampling:

Backward pass: $$\boldsymbol{G^{\star}_{u,t-1}} \leftarrow \mathbf{max}(\boldsymbol{G^{\star}_{u,t} - \bar{R}_u, G^{\star}_{u,t-1}}) \qquad \boldsymbol{Eq.22}$$

Forward pass: $$G^{\star}_{u,t} \leftarrow \max(G^{\star}_{u,t-1} - \bar{R}_u, G^{\star}_{u,t}) \qquad Eq.23$$

Then we apply minimum output and rounding:

$$\boldsymbol{G^{\text{adj}}_{u,t}} = \mathbf{max}\left\{\boldsymbol{G^{\star}_{u,t}, \underline{P}_u}\right\} \qquad \boldsymbol{Eq.24}$$

2.6.3. *Facility level probabilistic sampling*

Eq. 25 defines the initial, unconstrained hourly generation $G_{(u,t)}^{raw}$ for each unit u, which is drawn from a facility-specific empirical distribution conditioned on the day type and hour of day. Specifically, generation is sampled from the lookup table Gen_u^{tbl} using the calendar label $\mathrm{DayLabel}(t)$, the hour index $\mathrm{Hour}(t)$, and a probabilistic draw p_ω. If the sum of raw generation across all units exceeds the system-level fossil envelope $\bar{F}_t$, generation is reduced prior to applying ramping constraints, either proportionally across units or by curtailing lowest-capacity-factor units first, to ensure $\sum_u G_{(u,t)} \leq \bar{F}_t$.

Each hour's unit generation $G_{u,t}^{\mathrm{raw}}$ is drawn from the facility distribution for draw $\omega \in p_\omega$:

$$\boldsymbol{G_{u,t}^{\mathrm{raw}} = \mathrm{Gen}_u^{\mathrm{tbl}}(\mathrm{DayLabel}(t), \mathrm{Hour}(t), p_\omega)} \qquad \boldsymbol{Eq. 25}$$

If $\sum_u G_{u,t}^{\mathrm{raw}} > \bar{F}_t$, proportional (or low CF first) reductions ensure $\sum_u G_{u,t} \leq \bar{F}_t$ before ramp passes.

2.7. Curtailments and unmet demand

When renewable energy generation exceeds the system's ability to use or store the energy (either by satisfying demand or charging batteries), output must be curtailed. Curtailments are calculated as the portion of renewable energy left unused after meeting demand and accounting for available battery storage capacity. We do not assign a monetary penalty for curtailment, consistent with other models (Frew et al., 2021).

When all available generation and import capacity is inadequate to satisfy hourly demand, an unmet demand penalty is applied. This approximates the economic costs of demand curtailment and/or brownouts and has been used by ISO-NE. Specifically, we consider a variable cost curve (SI Figure S2) used by ISO-NE to estimate unmet demand penalties (Potomac Economics, 2024).

2.7.1. *Energy balance*

Eq. 26 enforces hourly energy balance. On the supply side, total non-fossil generation $\sum_{g \neq \mathrm{Fossil}} G_{(g,t)}$, imports I_t, battery discharge d_t, and fossil unit generation $\sum_u G_{(u,t)}$ must equal total demand D_t plus energy absorbed by battery charging c_t, renewable curtailment $Curt_t$, and unmet demand $Short_t$.

$$\boldsymbol{\sum_{g \neq \mathrm{Fossil}} G_{g,t} + I_t + d_t + \sum_u G_{u,t} \; = \; D_t + c_t + \mathrm{Curt}_t + \mathrm{Short}_t} \qquad \boldsymbol{Eq. 26}$$

2.7.2. *Curtailments and shortages*

Curtailment occurs when low-carbon generation exceeds the system's ability to absorb energy through demand satisfaction or battery charging. Unmet demand occurs when all available generation, battery discharge, and imports are insufficient to satisfy hourly demand. These quantities are represented as slack variables in the system energy balance.

Eq. 26 enforces hourly energy balance. Eq. 27 and Eq. 28 formally define curtailment $Curt_t$ and unmet demand $Short_t$ as nonnegative residuals that close the balance. Eq. 29 defines a diagnostic balance residual $BalRes_t$, which must be approximately zero and is used to verify numerical consistency.

After unit-level fossil dispatch is finalized, total fossil generation is recomputed (Eq. 30), and the model iterates over battery storage and imports to restore system-level consistency. Battery state of charge and charging and discharging flows are recalculated subject to the same technical constraints (Eq. 31), and imports are reallocated using the available headroom. This procedure yields calibrated net imports $I_t^{net,cal}$, curtailment $Curt_t^{cal}$, unmet demand $Short_t^{cal}$, and an updated diagnostic residual $BalRes_t^{cal}$, which is reported for the first calibration pass.

$$\mathbf{Curt}_{\boldsymbol{t}} = \mathbf{max}\,\{\mathbf{0}, \boldsymbol{G}_{\boldsymbol{t}}^{\mathbf{low\ carbon}} + \boldsymbol{I}_{\boldsymbol{t}} + \sum_{\boldsymbol{u}} \boldsymbol{G}_{\boldsymbol{u},\boldsymbol{t}} - \boldsymbol{D}_{\boldsymbol{t}} - \boldsymbol{c}_{\boldsymbol{t}}\} \qquad \boldsymbol{Eq.\,27}$$

$$\mathbf{Short}_{\boldsymbol{t}} = \max\,\{0, D_t - G_t^{\text{low carbon}} - I_t - d_t - \sum_{u} G_{u,t}\} \qquad Eq.\,28$$

Diagnostics residual must approximate to ≈ 0:

$$\mathbf{BalRes}_{\boldsymbol{t}} = \left(\boldsymbol{G}_{\boldsymbol{t}}^{\mathbf{low\ carbon}} + \boldsymbol{I}_{\boldsymbol{t}} + \sum_{\boldsymbol{u}} \boldsymbol{G}_{\boldsymbol{u},\boldsymbol{t}} + \boldsymbol{d}_{\boldsymbol{t}}\right) - (\boldsymbol{D}_{\boldsymbol{t}} + \boldsymbol{c}_{\boldsymbol{t}} + \mathbf{Curt}_{\boldsymbol{t}} + \mathbf{Short}_{\boldsymbol{t}}) \qquad \boldsymbol{Eq.\,29}$$

Iteration over battery storage and imports

Given finalized fossil dispatch $G_{u,t}^{\text{adj}}$, recompute battery and imports against

$$\boldsymbol{G}_{\boldsymbol{t}}^{\mathbf{fos}} \equiv \sum_{\boldsymbol{u}} \boldsymbol{G}_{\boldsymbol{u},\boldsymbol{t}}^{\mathbf{adj}} \qquad \boldsymbol{Eq.\,30}$$

Re-evaluate surplus or deficit on $(G_t^{\text{low carbon}} + I_t)$, rerun storage state with the same guards and caps, then recompute imports with headroom allocation to obtain $I_t^{\text{net,cal}}$, new $\text{Curt}_t^{\text{cal}}$, $\text{Short}_t^{\text{cal}}$, and calibrated SOC or flows:

$$\mathbf{SOC}_{\boldsymbol{t}}^{\mathbf{cal}} = \mathbf{min}\,\{\mathbf{max}\,(\boldsymbol{\rho}\,\mathbf{SOC}_{\boldsymbol{t-1}}^{\mathbf{cal}} + \boldsymbol{\eta}\,\boldsymbol{c}_{\boldsymbol{t}}^{\mathbf{cal}} - \frac{\mathbf{1}}{\boldsymbol{\eta}}\boldsymbol{d}_{\boldsymbol{t}}^{\mathbf{cal}}, \mathbf{0}), \boldsymbol{E}_{\mathbf{max},\boldsymbol{t}}\} \qquad \boldsymbol{Eq.\,31}$$

$$\text{Curt}_t^{\text{cal}} \geq 0, \text{Short}_t^{\text{cal}} \geq 0, I_t^{\text{net,cal}} \leq \bar{I}_t$$

Report an updated residual $\mathrm{BalRes}_t^{\mathrm{cal}}$as for the first pass.

2.8. CAPEX, FOM,VOM, and fueling costs

We calculate the capital expenditures (CAPEX), fixed operations and maintenance (FOM), and variable operations and maintenance (VOM) and fueling costs associated with the pathways described in SI Section 1. For all technologies except SMRs, these calculations leverage annual data from the 2024 NREL ATB using mature market rates with a 30-year recovery period, pooled (uniform distribution) across different ATB technology cost scenarios ("conservative", "moderate" and "advanced"). For SMRs, we use the 2024 NREL ATB nascent market rate, with a 30-year recovery period pooled across different ATB technology cost scenarios starting in 2030. This method of calculating CAPEX includes direct land acquisition costs.

CAPEX accrues in the year of deployment of a new generation or transborder transmission asset in each Pathway. FOM and VOM recur in every year of operation of a new or existing generation asset. FOM and VOM are not calculated for existing transmission assets because these do not vary across pathways. Costs are actualized to a net present value (NPV) at a discount rate specified by the user. We adopt a real discount rate of 2 %, consistent with U.S. EPA guidance (Office of Management and Budget, 2023), which use for results presented in the main text, and perform a sensitivity analysis for rates of 1.5 %, 2 %, and 2.5 %. While higher rates reduce absolute NPVs, the ranking of pathways remains unchanged (SI Tables S10–S12).

In this study, costs for new transmission infrastructure focus solely on lines connecting New England with other regional transmission organizations, notably cross-border connections with Quebec. CAPEX and FOM costs associated with transmission infrastructure are modeled based on the total capacity of the line ($ per MW). Therefore, we use CAPEX ($0.7–$1.0 million per MW) and FOM ($700 - $1,000 per MW) values based on cost estimates for the New England Clean Energy Connect (roughly $950 million for a 1200 MW line) reported by Calder et al. (2022) adjusted to 2024-USD. To capture uncertainty, following industry guidelines (e.g., Association for the Advancement of Cost Engineering International recommended practices for "Class 3" cost estimates), total CAPEX and FOM costs are drawn from a normal distribution with 95% confidence interval ±20% around the mean reported figure (Dysert, 2016).

We calculate fueling costs by multiplying annual generation by a fueling cost per MWh generated. We utilized the 2024 NREL ATB data for large nuclear and biomass fuel costs, applying mature market rates with a 30-year recovery period and pooling results across various ATB scenarios. For SMRs, we employed the 2024 NREL ATB nascent market rate with a similar 30-year recovery period, also pooled across different ATB scenarios beginning in 2030. We derived the fossil generation fuel costs from the NREL ATB data (2021), pooling mature market rates with a 30-year recovery period across multiple ATB scenarios

As we describe in more detail in SI Section 5, there are conceptual disagreements on whether and how to account for Canada-side costs in U.S. decarbonization pathways that increase imports of Canadian hydropower. For the sensitivity analysis in which we apportion a fraction of Canada-side costs to a hydropower-dependent pathway (CAPEX and FOM costs incurred from new large Canadian hydropower plants in Quebec for Pathway B3(2)), we use estimates from ISO-NE reports, indicating an average cost of $7,144 kW^{-1} (2024-USD) (Commonwealth of

Massachusetts, 2020). Scaled to a class 5 dam, this equates to a range of 8.3 to 19.7 million-USD MW^{-1} (2024-USD) (Hollmann et al., 2014). This cost range reflects the variability in project locations, regulatory requirements, and construction complexities. Moreover, IEA (2010) estimates that hydropower FOM costs are 1.5% to 2.5% of CAPEX annually which is 0.12-0.49 million-USD MW^{-1} year^{-1} (2024-USD).

Sources and details of probabilistic treatment for all direct cost parameters are provided in SI Table S5. A summary of all resulting costs (mean and range) is presented in SI Tables S10, S11 and S12. All costs are easily changed via user input to adapt this generalizable framework to other regions or countries.

Eq. 32 defines annual capital expenditures Cost_y^{CAPEX} as the sum of capital costs for all generation and transmission assets $a$commissioned in year y, where A_y^+ denotes the set of newly deployed assets in that year. Eq. 33 defines annual fixed operations and maintenance costs Cost_y^{FOM}as the sum of fixed costs for all assets $A_y$operating in year y.

Eq. 34 defines hourly variable operations and maintenance costs Cost_t^{VOM} as the sum over all generation technologies $g$of technology-specific variable cost coefficients $v_g$multiplied by hourly generation $G_{(g,t)}$. Eq. 35 defines hourly fueling costs Cost_t^{fuel} as the sum of unit-level fuel costs $f_u$multiplied by adjusted fossil generation $G_{(u,t)}^{adj}$, plus technology-level fuel costs for nuclear, biomass, and SMR generation, which are modeled at the aggregate technology level.

$$\mathbf{Cost}_{\boldsymbol{y}}^{\mathbf{CAPEX}} = \sum_{\boldsymbol{a}\in\boldsymbol{\mathcal{A}}_{\boldsymbol{y}}^{+}} \mathbf{CAPEX}_{\boldsymbol{a}} \qquad \boldsymbol{Eq.32}$$

$$\mathbf{Cost}_{\boldsymbol{y}}^{\mathbf{FOM}} = \sum_{a\in\mathcal{A}_y} \mathrm{FOM}_{a,y} \qquad Eq.33$$

$$\mathbf{Cost}_{\boldsymbol{t}}^{\mathbf{VOM}} = \sum_{g} v_g\, G_{g,t} \qquad Eq.34$$

$$\mathbf{Cost}_{\boldsymbol{t}}^{\mathbf{fuel}} = \sum_{u} f_u\, G_{u,t}^{\mathrm{adj}} + \sum_{\substack{g\in\{\mathrm{SMR},\\ \mathrm{Biomass},\\ \mathrm{Nuclear}\}}} f_g\, G_{g,t} \qquad Eq.35$$

2.9. Costs of imports from other jurisdictions

We estimated import costs from NYISO to be between 0.78¢ to 2.41¢ kWh^{-1} (2024-USD) (uniform distribution) within the U.S. (DeSantis et al., 2021). For imports from Canada, using the CHPE (339 miles) as a reference, we estimate delivery costs to be approximately 2.12¢ kWh^{-1} (2024-USD) (Calder et al., 2022). Notably, this figure represents an upper bound estimate, while a similar uncertainty range as applied for NYISO yields a lower bound estimate of 0.78¢ kWh^{-1} (2024-USD). These import costs apply to new and existing infrastructure, and we apply these as standardized levelized import costs from other jurisdictions.

Eq. 36 defines hourly import costs $\mathrm{Cost}_t^{imports}$ as the sum over all importing jurisdictions $j$of jurisdiction-specific levelized import cost coefficients $\kappa_j$multiplied by total imports from that jurisdiction. Total imports include both long-term contractual imports $I_{(j,t)}^{LT}$ and spot-market imports $I_{(j,t)}^{spot}$, ensuring that import costs are applied consistently to all electricity imported into the system regardless of contract structure.

$$\mathbf{Cost}_{\boldsymbol{t}}^{\mathbf{imports}} \quad = \quad \sum_{\boldsymbol{j}} \boldsymbol{\kappa}_{\boldsymbol{j}}(\boldsymbol{I}_{\boldsymbol{j},\boldsymbol{t}}^{\mathbf{LT}} + \boldsymbol{I}_{\boldsymbol{j},\boldsymbol{t}}^{\mathbf{spot}}) \qquad \boldsymbol{Eq.36}$$

2.10. Greenhouse gas emissions costs

We use the U.S. EPA estimates for social cost of GHG emissions at 2% discount rate in 2025 as \$253.71 tonne-CO$_2^{-1}$, \$2,423.48 tonne-CH$_4^{-1}$ and \$72,126.48 tonne-N$_2$O^{-1} in 2024 USD, escalating over time (U.S. EPA, 2023). These costs are applied to fossil fuel GHG emissions described in SI Section 2.6. As described in SI Section 5, we consider two alternative methods for valuing methane impacts from new hydroelectric generation in Quebec. Both Scenarios B3(1) and B3(2) consider substantially increased hydroelectric imports such that new generation capacity is triggered. In Scenario B3(1), emissions are valued based on the installed capacity of the reservoir. In Scenario B3(2), they are valued based on the power imported at each timestep. We assume that hydropower imports in other pathways are too low to trigger new development of reservoir hydropower in Canada and hence, from a consequentialist perspective, do not value methane emissions.

Eq. 37 defines hourly greenhouse gas damage costs Cost_t^{GHG} as the product of pollutant-specific social cost coefficients and corresponding emissions. Social cost coefficients $s_{(g,y)}^{GHG}$ for CO_2, CH_4, and N_2O are taken from U.S. EPA estimates at a 2% discount rate, expressed in 2024 USD and escalated over time. For all pathways, fossil fuel emissions of CO_2, CH_4, and N_2O enter the cost calculation through hourly emissions $E_t^{(g)}$.

For Scenario B3(1), methane emissions associated with new reservoir hydropower in Québec are valued based on installed reservoir capacity through an additional reservoir-related methane term $E_{(res,t)}^{CH_4}$. For Scenario B3(2), methane impacts are instead valued proportionally to hourly hydropower imports from Québec, represented by $\theta_{res} I_t^{HQ}$. In all other pathways, hydropower imports are assumed insufficient to induce new reservoir development, and only fossil fuel emissions are valued.

$$\mathrm{Cost}_t^{\mathrm{GHG}} = \begin{cases} s_{\mathrm{CO_2},y}^{\mathrm{GHG}} E_t^{\mathrm{CO_2}} + s_{\mathrm{CH_4},y}^{\mathrm{GHG}} (E_t^{\mathrm{CH_4}} + E_{\mathrm{res},t}^{\mathrm{CH_4}}) + s_{\mathrm{N_2O},y}^{\mathrm{GHG}} E_t^{\mathrm{N_2O}} & Scenario\ B3(1) \\ s_{\mathrm{CO_2},y}^{\mathrm{GHG}} E_t^{\mathrm{CO_2}} + s_{\mathrm{CH_4},y}^{\mathrm{GHG}} (E_t^{\mathrm{CH_4}} + \theta_{\mathrm{res}} I_t^{\mathrm{HQ}}) + s_{\mathrm{N_2O},y}^{\mathrm{GHG}} E_t^{\mathrm{N_2O}} & Scenario\ B3(2) \\ s_{\mathrm{CO_2},y}^{\mathrm{GHG}} E_t^{\mathrm{CO_2}} + s_{\mathrm{CH_4},y}^{\mathrm{GHG}} E_t^{\mathrm{CH_4}} + s_{\mathrm{N_2O},y}^{\mathrm{GHG}} E_t^{\mathrm{N_2O}} & Other\ scenarios \end{cases} \qquad Eq.37$$

2.11. Air pollutant emissions costs

Eq. 38 defines hourly air pollution damage costs Cost_t^{AP3} as the sum over pollutant species $k \in \{\mathrm{NO}_x, \mathrm{SO}_2, \mathrm{PM}_{2.5}, \mathrm{PM}_{10}, \mathrm{VOC}, \mathrm{CO}\}$ of pollutant-specific marginal damage values $\hat{v}^k$ from the AP3 model multiplied by corresponding hourly emissions E_t^k. Resulting marginal emissions cost estimates at the facility level are reported in SI Table S8.

$$\mathbf{Cost}_t^{\mathbf{AP3}} \quad = \quad \sum_{\substack{k \in \{\mathbf{NO_x}, \mathbf{SO_2}, \mathbf{PM_{2.5}}, \\ \mathbf{PM_{10}}, \mathbf{VOC}, \mathbf{CO}\}}} \hat{\boldsymbol{v}}^{\boldsymbol{k}}\, \boldsymbol{E}_{\boldsymbol{t}}^{\boldsymbol{k}} \qquad \boldsymbol{Eq.38}$$

Resulting marginal emissions costs for each facility are provided in SI Table S8. Moreover, Eq. 39 defines unit-level emissions $E_{(u,t)}^k$ for pollutant k as the product of adjusted generation $G_{(u,t)}^{adj}$ and a pollutant-specific emissions intensity ϕ_u^k. Eq. 40 aggregates emissions across all generating units to obtain total system-level hourly emissions E_t^k, which are used in downstream damage cost calculations.

Because unit-level emissions data are incomplete for a subset of units and pollutants, Eq. 41 defines a substitution rule for emissions intensities. When sufficient historical observations exist, unit-specific mean emissions intensities $\hat{\phi}_u^k$ are used. When unit-level data are unavailable, emissions intensities default to a global mean $\bar{\phi}^k$ computed across all units. This procedure ensures complete and internally consistent emissions accounting while preserving unit-level heterogeneity wherever data permit.

$$\boldsymbol{E}_{\boldsymbol{u,t}}^{\boldsymbol{k}} \quad = \quad \boldsymbol{\phi}_{\boldsymbol{u}}^{\boldsymbol{k}}\, \boldsymbol{G}_{\boldsymbol{u,t}}^{\mathbf{adj}}, \boldsymbol{k} \in \{\mathbf{CO_2}, \mathbf{NO_x}, \mathbf{SO_2}, \dots\} \qquad \boldsymbol{Eq.39}$$

$$\boldsymbol{E}_{\boldsymbol{t}}^{\boldsymbol{k}} \quad = \quad \sum_u E_{u,t}^k \qquad Eq.40$$

Let $\hat{\phi}_u^k$ be the unit's mean intensity estimated from available hours. If unavailable, fall back to the global mean $\bar{\phi}^k$across units:

$$\boldsymbol{\phi}_{\boldsymbol{u}}^{\boldsymbol{k}} \quad \leftarrow \quad \begin{cases} \hat{\boldsymbol{\phi}}_{\boldsymbol{u}}^{\boldsymbol{k}}, & \text{if defined} \\ \bar{\boldsymbol{\phi}}^{\boldsymbol{k}}, & \text{otherwise} \end{cases} \Rightarrow \boldsymbol{E}_{\boldsymbol{u,t}}^{\boldsymbol{k}} = \boldsymbol{\phi}_{\boldsymbol{u}}^{\boldsymbol{k}}\, \boldsymbol{G}_{\boldsymbol{u,t}}^{\mathbf{adj}} \qquad \boldsymbol{Eq.41}$$

2.12. Unmet demand penalty costs

During periods of capacity scarcity, when available supply is insufficient to meet demand, the marginal cost of electricity increases sharply due to market scarcity pricing and penalties imposed by ISO-NE under its pay-for-performance mechanism (SI Figure S2). The model assumes perfect foresight of demand over the ramping horizon, which is used to anticipate upcoming peaks and ramp fossil generation in advance so as to minimize infeasible ramping and resulting unmet demand, rather than to optimize battery charging decisions. Eq. 42 defines hourly shortage penalties Cost_t^{short}as the product of unmet demand $Short_t^{cal}$and the ISO-NE pay-for-performance penalty rate π_{short}, set to \$3,500 MWh^{-1} 2024 USD (Potomac Economics, 2024).

$$\mathbf{Cost}_t^{\mathbf{short}} = \boldsymbol{\pi}_{\mathbf{short}} \cdot \mathbf{Short}_t^{(\mathbf{cal})} \qquad \boldsymbol{Eq.42}$$

2.13. Direct costs

Eq. 43 defines timestep-level direct operating costs Cost_t^{direct} as the sum of all costs that vary with hourly system operation, including variable operations and maintenance Cost_t^{VOM}, fuel expenditures Cost_t^{fuel}, and electricity import costs $\text{Cost}_t^{imports}$. These costs depend on realized generation, fuel use, and imports in each hour.

Eq. 44 aggregates hourly operating costs across all timesteps t within year y and combines them with annual costs that accrue independently of hourly operation. These include capital expenditures Cost_y^{CAPEX}, which occur in the year new generation or transmission assets are commissioned, and fixed operations and maintenance costs Cost_y^{FOM}, which recur annually for all operating assets. This formulation ensures that both short-run operating costs and long-run investment-related costs are consistently captured at the annual level.

$$\mathbf{Cost}_t^{\mathbf{direct}} = \mathbf{Cost}_t^{\mathbf{VOM}} + \mathbf{Cost}_t^{\mathbf{fuel}} + \mathbf{Cost}_t^{\mathbf{imports}} \qquad \boldsymbol{Eq.43}$$

$$\mathbf{Cost}_y^{\mathbf{direct}} = \sum_{t\in y} \text{Cost}_t^{\text{direct}} + \text{Cost}_y^{\text{CAPEX}} + \text{Cost}_y^{\text{FOM}} \qquad Eq.44$$

2.14. Indirect costs

Eq. 45 defines timestep-level indirect costs $\text{Cost}_t^{indirect}$ as the sum of external damage costs from greenhouse gas emissions, air pollutant emissions, and unmet demand penalties. These costs represent societal impacts that are not directly borne by generators or system operators but are relevant for evaluating welfare outcomes across pathways.

Eq. 46 aggregates hourly indirect costs across all timesteps t within year y to obtain total annual indirect costs, ensuring that climate damages, air quality impacts, and reliability penalties are consistently accounted for over time.

$$\mathbf{Cost}_t^{\mathbf{indirect}} = \mathbf{Cost}_t^{\mathbf{GHG}} + \mathbf{Cost}_t^{\mathbf{AP3}} + \mathbf{Cost}_t^{\mathbf{short}} \qquad \boldsymbol{Eq.45}$$

$$\mathbf{Cost}_y^{\mathbf{indirect}} = \sum_{t\in y} \text{Cost}_t^{\text{indirect}} \qquad Eq.46$$

2.15. Total system cost and NPV

Eq. 47 defines total system cost in year y as the sum of direct system costs and indirect societal costs. This captures both expenditures incurred by the electricity system and external damages associated with emissions and reliability shortfalls.

Eq. 48 computes the net present value (NPV) of total system costs by discounting annual costs over the analysis horizon Y to a reference year y_0 using a real discount rate r. This formulation allows consistent comparison of costs across pathways with different temporal profiles of investment, operation, and external impacts.

$$\boldsymbol{\mathrm{Cost}_y} \quad = \quad \boldsymbol{\mathrm{Cost}_y^{\mathrm{direct}} + \mathrm{Cost}_y^{\mathrm{indirect}}} \qquad \boldsymbol{Eq.47}$$

$$\mathbf{NPV} \quad = \quad \sum_{y \in \mathcal{Y}} \frac{\mathrm{Cost}_y}{(1+r)^{y-y_0}} \qquad Eq.48$$

3. Monte Carlo analysis

ISO-NE supplies discretized, joint distributions for the capacity factors of solar and onshore and offshore wind identified as probability percentiles (1, 5, 10, 50, 90, 95, 99% yearly output). These percentiles account for the hourly correlations between, for example, wind and solar capacity factors, capacity factors at different hours, etc.

We apply linear interpolation to create hourly schedules for 99 percentiles $p_\omega \in \{1, \dots, 99\}$. The model draws randomly from distributions assigned for uncertain parameters for both the energy system, including from among the 99 percentiles for capacity output, and for ecological, health, and economic impacts defined in text. Initial parameter draws are propagated through the model so each simulation run tracks correlations in underlying input variables.

Let the random percentile sequence for simulation index be $p_\omega \in \{1, \dots, 99\}$. For each hour t:

$$\boldsymbol{\mathrm{CF}_{\mathrm{Solar},t}(\omega)} \quad = \quad \boldsymbol{\mathrm{CF}_{\mathrm{Solar}}^{\mathrm{tbl}}(\mathrm{DayLabel}(t), \mathrm{Hour}(t), p_\omega)} \qquad \boldsymbol{Eq.49}$$

$$\boldsymbol{\mathrm{CF}_{\mathrm{Wind_{on}},t}(\omega)} \quad = \quad \mathrm{CF}_{\mathrm{Wind_{on}}}^{\mathrm{tbl}}(\mathrm{DayLabel}(t), \mathrm{Hour}(t), p_\omega) \qquad Eq.50$$

$$\boldsymbol{\mathrm{CF}_{\mathrm{Wind_{off}},t}(\omega)} \qquad \mathrm{CF}_{\mathrm{Wind_{off}}}^{\mathrm{tbl}}(\mathrm{DayLabel}(t), \mathrm{Hour}(t), p_\omega) \qquad Eq.51$$

Imports percentiles are analogously sampled per intertie $j \in \{\mathrm{HQ}, \mathrm{NYISO}, \mathrm{NBSO}\}$ from the imports CF table:

$$\boldsymbol{\mathrm{CF}_{j,t}^{\mathrm{spot}}(\omega)} \quad = \quad \boldsymbol{\mathrm{CF}_j^{\mathrm{tbl}}(\mathrm{DayLabel}(t), p_\omega)} \qquad \boldsymbol{Eq.52}$$

4. Model validation

To validate the model, we compared results for Scenario B1 of this model (run deterministically) against results for the *High Electrification* pathway presented in the Massachusetts 2050 Decarbonization Roadmap. We extracted ISO-NE estimated values for Total Annual Load and Renewable Generation at five-year intervals

$$y_{validation} \in \{2025, 2030, 2035, 2040, 2045, 2050\}$$

4.1. Total annual load calculation

For the model trajectory, Total Annual Load ($L_{model,t}$) was calculated as the sum of all generation sources and net imports, consistent with the ISO-NE accounting method:

$$\boldsymbol{L_{model,t} = \sum_{g\in G} Gen_{g,t} + Imports_{net,t}} \qquad \textbf{Eq. 53}$$

Where:

- $Gen_{g,t}$represents the total annual generation from source g(solar, wind, hydro, biomass, nuclear, fossil).
- $Imports_{net,t}$represents the calibrated net imports from neighboring jurisdictions.

4.2. Goodness-of-fit metric

To quantify the alignment between the model outputs and the ISO-NE estimated trajectories, we calculated the coefficient of determination (R^2) for both *Total Annual Load* and *Renewable Generation*.

$$\boldsymbol{R^2 = 1 - \frac{SS_{res}}{SS_{tot}}} \qquad \textbf{Eq. 54}$$

Where the sum of squares of residuals (SS_{res})and the total sum of squares (SS_{tot})are given by:

$$\boldsymbol{SS_{res} = \sum_{t} (y_{benchmark,t} - y_{model,t})^2} \qquad \textbf{Eq. 55}$$

$$\boldsymbol{SS_{tot}} = \sum_{t} (y_{benchmark,t} - \bar{y}_{benchmark})^2 \qquad Eq. 56$$

Here:

- $y_{benchmark,t}$is the observed ISO-NE estimated value in year t.
- $y_{model,t}$is the model's median predicted value in year t.
- $\bar{y}_{benchmark}$is the mean of the ISO-NE estimated values over the validation period.

5. Accounting for costs of increased imports of Canadian hydroelectric power

There is debate about how to value direct and indirect costs associated with increased imports of Canadian hydroelectric power to the U.S. (Calder et al., 2022; Gazar et al., 2024). Within the U.S., direct costs are those associated with investments in new transmission infrastructure plus costs of imported power (either purchased on the spot market or negotiated in a long-term contract). If imports to one U.S. market have the effect of reducing exports to another U.S. market, then increased fossil fuel generation in that other market can be counted as indirect costs.

Costs in Canada derive from direct expenses in building and operating reservoirs and impacts from environmental and social effects of reservoir construction (e.g., global climate impacts from reservoir methane emissions, local impacts on Indigenous food systems, etc.).

Pathway B3 specifically assumes that new hydroelectric generation in Canada would be necessary to sustain the level of increased exports to the U.S. (Commonwealth of Massachusetts, 2020). From a "consequentialist" perspective (Calder et al., 2022; Curran et al., 2005; Earles & Halog, 2011; Ekvall, 2019), it is therefore necessary to account for the generation-side impacts of that hydroelectric development, i.e., costs in Canada. We retain two alternative accounting methods corresponding to two unique pathways: (1) U.S. costs only, i.e., costs of U.S. infrastructure plus costs of imports (a lower bound estimate of the costs of generation in Canada), corresponding to Pathway B3(1), described in SI Section 2.5; and (2) total social costs, accounting for costs of infrastructure in the U.S. and Canada (SI Section 2.5), plus indirect costs from reservoir methane (CH4) emissions, proportionally to the power exported to the U.S., corresponding to Pathway B3(2) (SI Section 2.10). Method (2) excludes the value of the imports/exports because this is not a cost to society from the energy system but rather a payment between actors. Figure S1 illustrates how direct (U.S. infrastructure, power purchase) and indirect (fossil displacement, reservoir CH_4) costs are captured under the two cost-accounting methods (U.S.-only vs. total social cost).

Other pathways consider that Canadian hydroelectric resources are leveraged without stimulating new hydroelectric development in Canada, and therefore, from a consequentialist perspective, do not require consideration of impacts associated with existing reservoirs. While "attributional" analyses that apportion impacts of all existing infrastructure to incremental transmission expansion are common, they are known to overestimate total costs in comparison with alternatives when there is no causal connection between, for example, new transmission and new generation (Calder et al., 2020, 2022; Curran et al., 2005; Gazar et al., 2024)

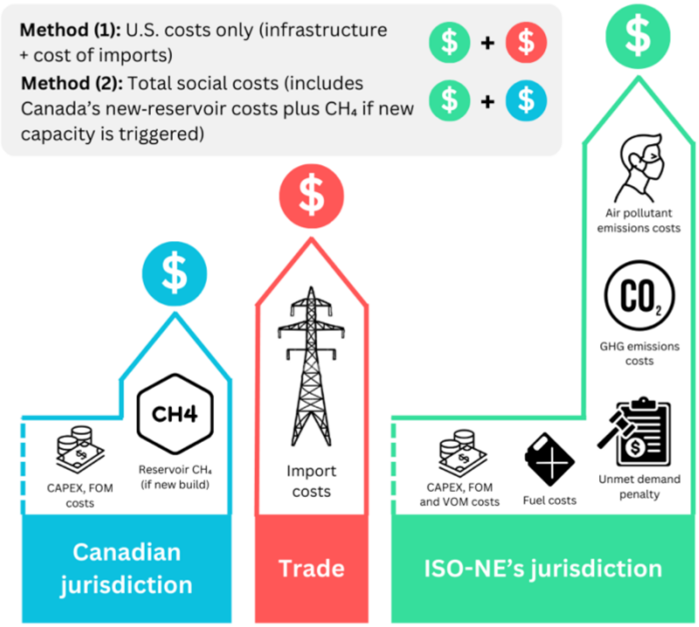

Figure S1: Illustration of how direct and indirect costs are allocated for imports of Canadian hydropower under two accounting methods.
Method (1) ("U.S. costs only") includes U.S. infrastructure plus payments for imports. Method (2) ("total social costs") additionally includes new reservoir construction costs and methane (CH_4) emissions in Canada if new hydropower capacity is triggered. Payments for imports are treated as transfers within the overall system and not net social costs. Where imports to one U.S. region displace exports that would have gone to another, any increased fossil generation in that second region can be counted as an additional indirect cost.

Delwiche et al., (2022) reported emissions ranging from 5,685 to 16,744 mg CH_4-C day^{-1} for three existing reservoirs in Quebec, Canada (Eastmain, Robert-Bourassa, and LaForge-1). These reservoirs span a range of trophic statuses, ages, surface areas, and other parameters believed to be important in determining the time course of CH_4 emissions. Because of uncertainties in (1) how these variables combine to determine emissions and (2) the location and characteristics of a hypothetical future reservoir, we estimate CH_4 emissions from a new hydroelectric facility in Quebec by pooling the above range of values into a uniform distribution and scaling by the generation demanded in Scenario B3 (up to 126.2 TWh per year or 62% of demand). The Eastmain reservoir powers turbines at Eastmain-1 (480 MW), Eastmain-1-A (768 MW) and Sarcelle (150 MW), while Laforge-1 (878 MW) and Robert-Bourassa (878 MW) are each associated with one dam for a total of 7,892 MW at an estimated average capacity factor of 0.65 (Hydro-Québec, 2025). Thus, we consider CH_4-C emissions using a uniform distribution of 0.16 to 1.22 kg CH_4-C per MWh imported. Details of facility specific methane emissions from Canadian reservoirs are provided in SI Table S9.

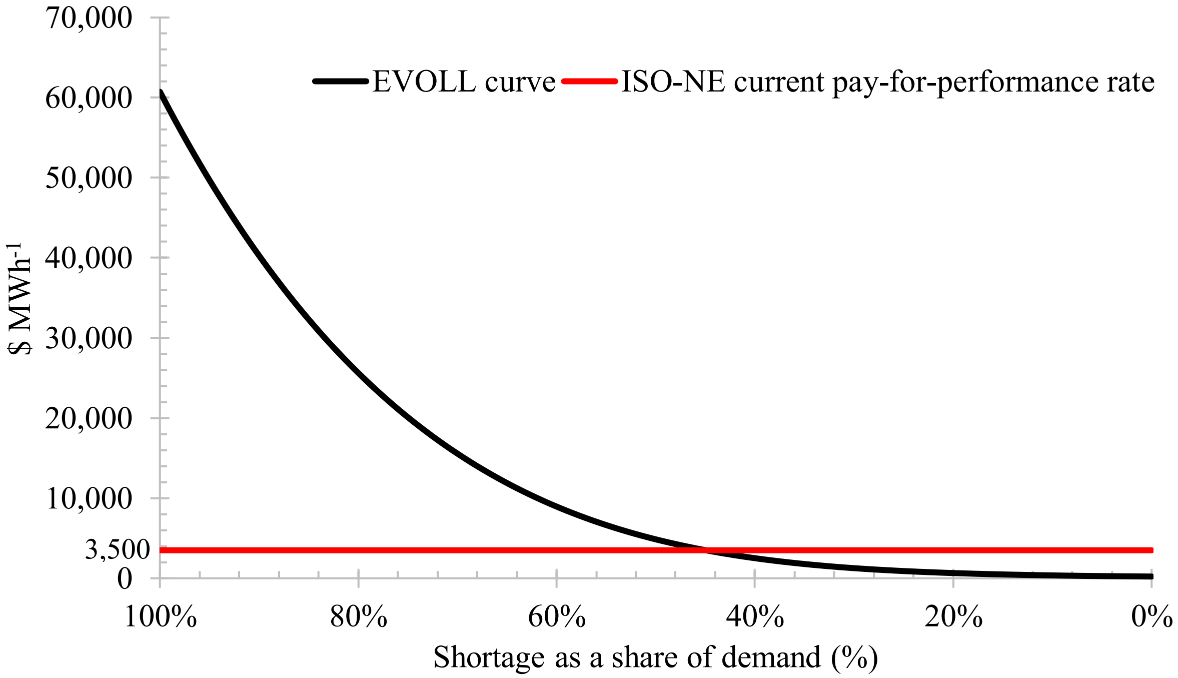

Figure S2: Pay for performance rates and the value of lost load curve used by ISO-NE adapted from the “2023 Assessment Of The ISO New England Electricity Markets” report prepared by Potomac Economics for ISO-NE (Potomac Economics, 2024)

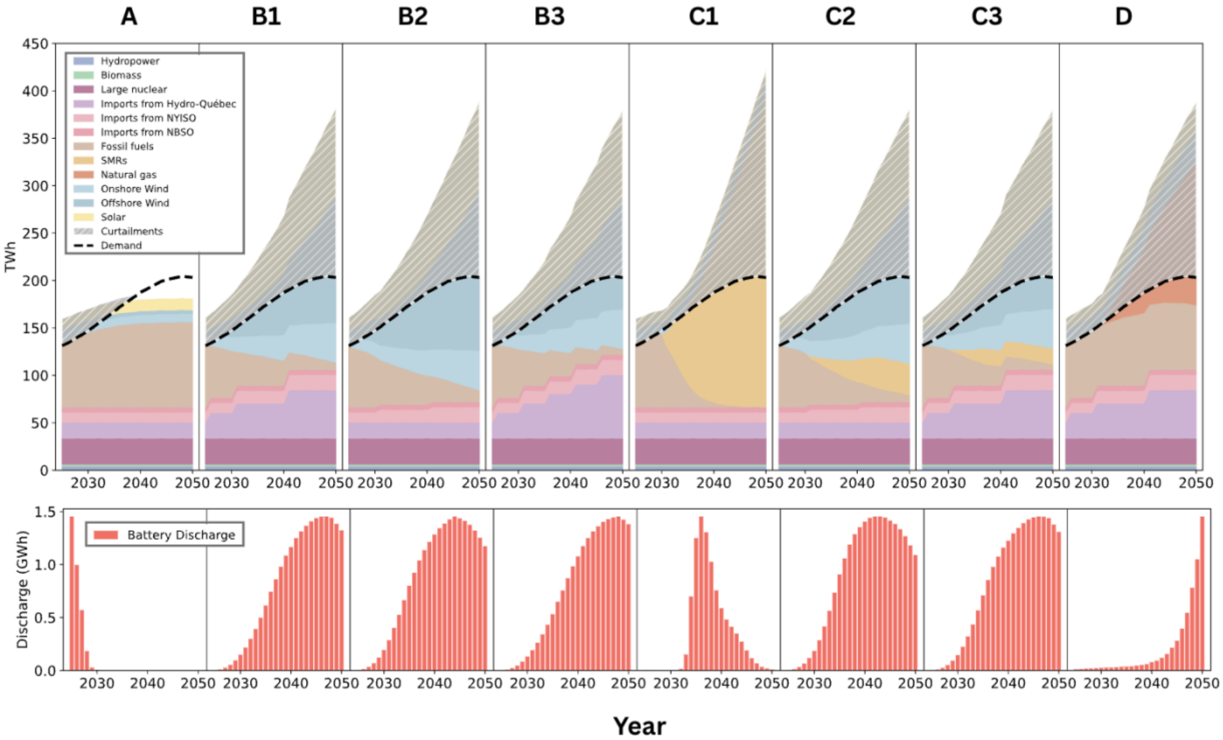

Figure S3: Modeled electricity generation by resource (top panels) and battery discharge (bottom panels) for the eight decarbonization pathways from 2025 to 2050 (simulation #1). Stacked areas in the upper charts indicate generation from hydropower, biomass, nuclear, imports, fossil fuels, natural gas, small modular reactors, onshore wind, offshore wind, and solar; the black dashed line shows the total demand. The greyed hashed region shows the total curtailments. The lower charts display annual battery discharge profiles (in GWh) under each pathway.

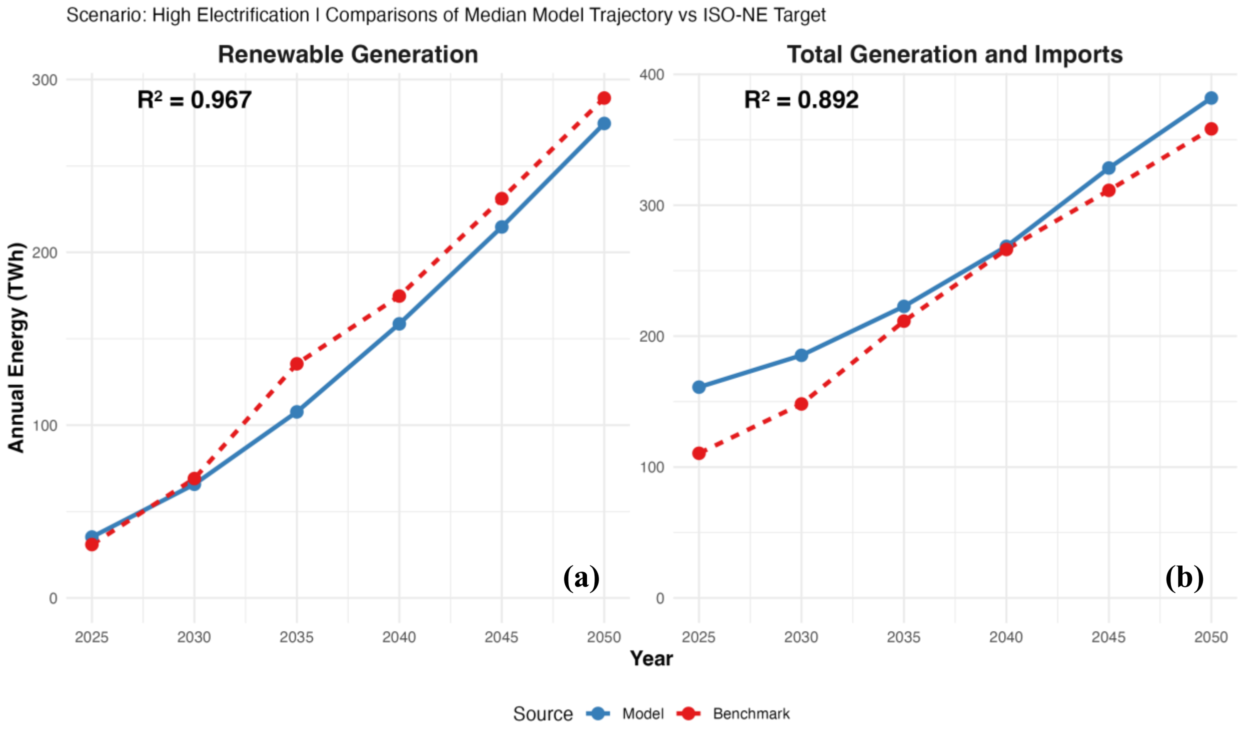

Figure S4: Deterministic validation of generation trajectories (2025–2050).
Comparison of the model's median simulated trajectories (blue solid lines) against the ISO-NE "High Electrification" ISO-NE estimated (red dashed lines). a) Renewable Generation shows near-perfect alignment (R2 = 0.97) and b) Total Annual Load (sum of all generation and imports) shows strong trajectory alignment ($R^2 = 0.89$), with the model projecting higher gross generation requirements due to the inclusion of probabilistic operational losses. Thus, validating the model's representation of the clean energy transition. ISO-NE estimated data source: Massachusetts 2050 Decarbonization Roadmap (Commonwealth of Massachusetts, 2020).

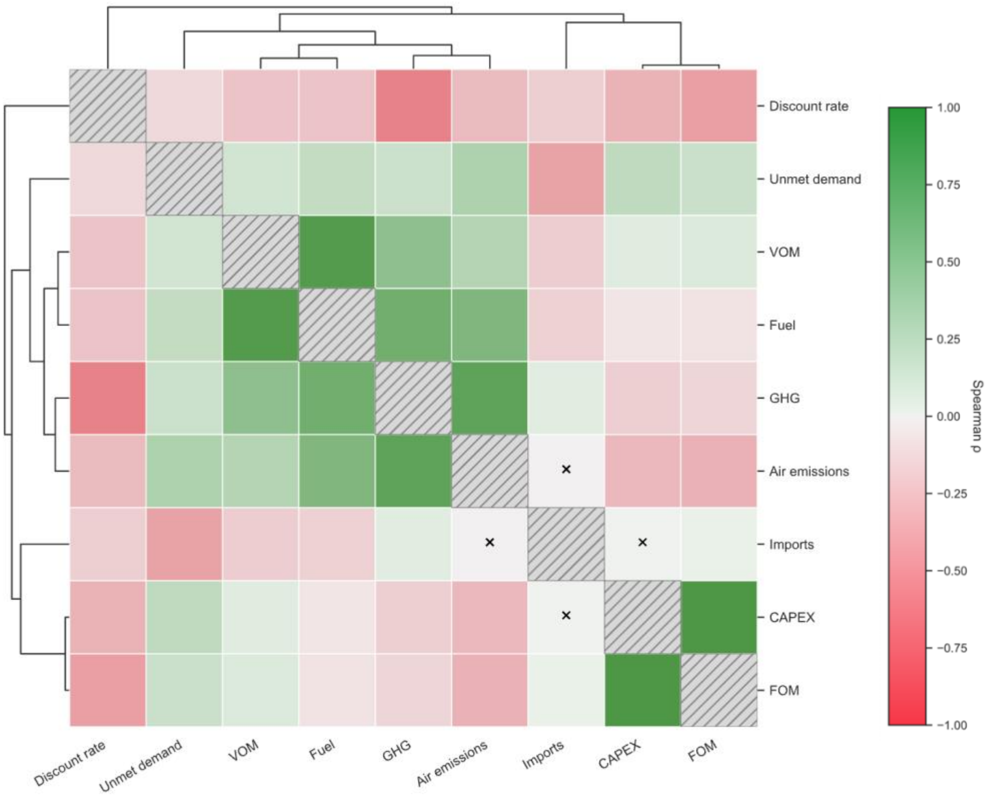

Figure S5: Spearman correlation matrix showing pairwise relationships between uncertain model parameters and outputs.

Positive correlations (green) indicate variables that increase together, while negative correlations (red) show inverse relationships. Hierarchical clustering highlights patterns of dependency across key uncertainty drivers such as GHG emissions, fuel costs, and investment parameters.

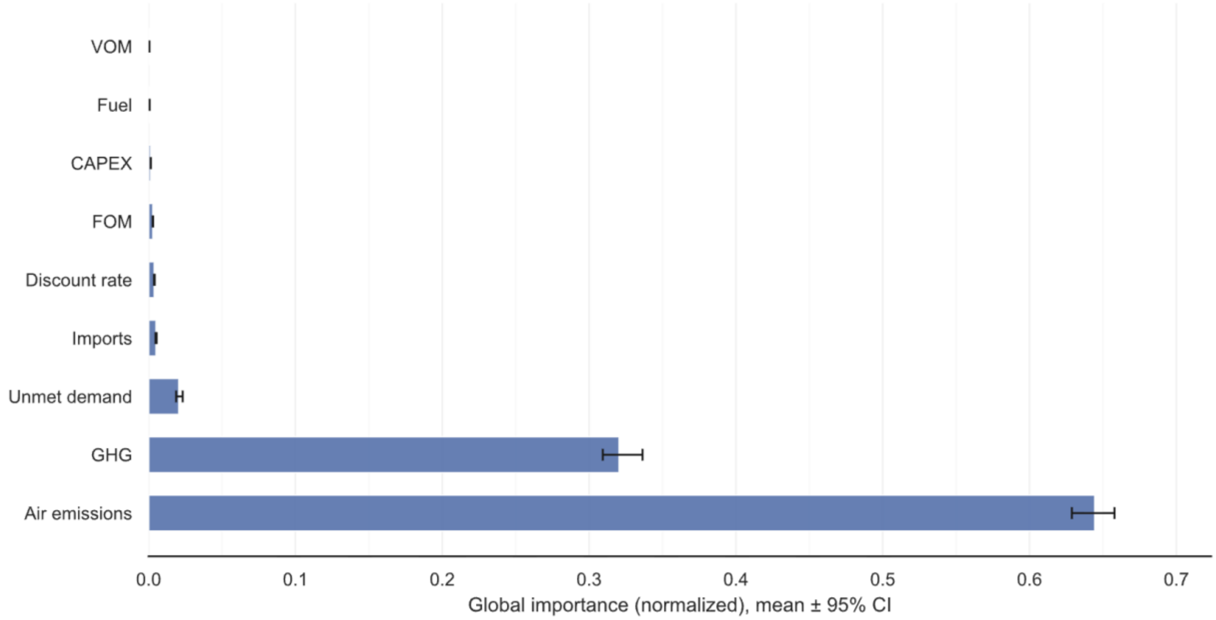

Figure S6: Normalized global importance of uncertainty sources for cost-related variables.
Air emissions and GHG uncertainties dominate overall variability, while other factors such as fuel, capital, and operational costs contribute minimally. Error bars represent 95% confidence intervals across model evaluations.

Table S2: Yearly capacity schedule for eight decarbonization pathways (2025–2050). All units are in megawatts.

Pathway A

Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Quebec	Imports from NBSO	Imports from NYISO	Storage
2025-2050	3350	900	400	9027	3233	974	0	0	2125	1050	3200	4199

Pathway B1

Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Quebec	Imports from NBSO	Imports from NYISO	Storage
2025	3350	900	400	10315	3563	1471	0	0	2125	1050	3200	4551
2026	3350	900	400	11833	3903	2029	0	0	3325	1050	3200	4968
2027	3350	900	400	13563	4254	2648	0	0	3325	1050	3200	5445
2028	3350	900	400	15490	4615	3327	0	0	3325	1050	3200	5976
2029	3350	900	400	17596	4988	4067	0	0	3325	1050	3200	6556
2030	3350	900	400	19864	5371	4867	0	0	3325	1050	3200	7180
2031	3350	900	400	22277	5764	5728	0	0	4525	1050	4000	7841
2032	3350	900	400	24819	6169	6650	0	0	4525	1050	4000	8536
2033	3350	900	400	27473	6584	7633	0	0	4525	1050	4000	9258
2034	3350	900	400	30221	7010	8676	0	0	4525	1050	4000	10003
2035	3350	900	400	33047	7446	9780	0	0	4525	1050	4000	10764
2036	3350	900	400	35934	7893	10944	0	0	4525	1050	4000	11537
2037	3350	900	400	38866	8351	12169	0	0	4525	1050	4000	12316
2038	3350	900	400	41824	8820	13455	0	0	4525	1050	4000	13096
2039	3350	900	400	44793	9299	14801	0	0	4525	1050	4000	13871
2040	3350	900	400	47756	9789	16209	0	0	4525	1050	4000	14637
2041	3350	900	400	50695	10290	17676	0	0	6225	1050	4800	15387

2042	3350	900	400	53593	10801	19205	0	0	6225	1050	4800	16117
2043	3350	900	400	56435	11324	20794	0	0	6225	1050	4800	16821
2044	3350	900	400	59203	11856	22444	0	0	6225	1050	4800	17493
2045	3350	900	400	61879	12400	24154	0	0	6225	1050	4800	18129
2046	3350	900	400	64448	12954	25925	0	0	6225	1050	4800	18723
2047	3350	900	400	66892	13519	27757	0	0	6225	1050	4800	19270
2048	3350	900	400	69195	14095	29650	0	0	6225	1050	4800	19764
2049	3350	900	400	71339	14681	31603	0	0	6225	1050	4800	20200
2050	3350	900	400	73308	15278	33617	0	0	6225	1050	4800	20572

Pathway B2

Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Quebec	Imports from NBSO	Imports from NYISO	Storage
2025	3350	900	400	9027	3233	1185	0	0	2125	1050	3200	4199
2026	3350	900	400	10315	3563	1820	0	0	2125	1050	3200	4551
2027	3350	900	400	11833	3903	2533	0	0	2125	1050	3200	4968
2028	3350	900	400	13563	4254	3322	0	0	2125	1050	3200	5445
2029	3350	900	400	15490	4615	4189	0	0	2125	1050	3200	5976
2030	3350	900	400	17596	4988	5133	0	0	2125	1050	3200	6556
2031	3350	900	400	19864	5371	6155	0	0	2125	1050	3200	7180
2032	3350	900	400	22277	5764	7253	0	0	2125	1050	4000	7841
2033	3350	900	400	24819	6169	8428	0	0	2125	1050	4000	8536
2034	3350	900	400	27473	6584	9681	0	0	2125	1050	4000	9258
2035	3350	900	400	30221	7010	11011	0	0	2125	1050	4000	10003
2036	3350	900	400	33047	7446	12418	0	0	2125	1050	4000	10764
2037	3350	900	400	35934	7893	13902	0	0	2125	1050	4000	11537
2038	3350	900	400	38866	8351	15463	0	0	2125	1050	4000	12316
2039	3350	900	400	41824	8820	17101	0	0	2125	1050	4000	13096
2040	3350	900	400	44793	9299	18817	0	0	2125	1050	4000	13871

2041	3350	900	400	47756	9789	20609	0	0	2125	1050	4000	14637
2042	3350	900	400	50695	10290	22479	0	0	2125	1050	4800	15387
2043	3350	900	400	53593	10801	24426	0	0	2125	1050	4800	16117
2044	3350	900	400	56435	11324	26450	0	0	2125	1050	4800	16821
2045	3350	900	400	59203	11856	28551	0	0	2125	1050	4800	17493
2046	3350	900	400	61879	12400	30729	0	0	2125	1050	4800	18129
2047	3350	900	400	64448	12954	32985	0	0	2125	1050	4800	18723
2048	3350	900	400	66892	13519	35317	0	0	2125	1050	4800	19270
2049	3350	900	400	69195	14095	37727	0	0	2125	1050	4800	19764
2050	3350	900	400	71339	14681	40214	0	0	2125	1050	4800	20200

Pathway B3

Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Quebec	Imports from NBSO	Imports from NYISO	Storage
2025	3350	900	400	10315	3563	1311	0	0	2125	1050	3200	4551
2026	3350	900	400	11833	3903	1798	0	0	3325	1050	3200	4968
2027	3350	900	400	13563	4254	2337	0	0	3325	1050	3200	5445
2028	3350	900	400	15490	4615	2930	0	0	3325	1050	3200	5976
2029	3350	900	400	17596	4988	3576	0	0	3325	1050	3200	6556
2030	3350	900	400	19864	5371	4275	0	0	3325	1050	3200	7180
2031	3350	900	400	22277	5764	5027	0	0	4525	1050	4000	7841
2032	3350	900	400	24819	6169	5832	0	0	4525	1050	4000	8536
2033	3350	900	400	27473	6584	6690	0	0	4525	1050	4000	9258
2034	3350	900	400	30221	7010	7601	0	0	4525	1050	4000	10003
2035	3350	900	400	33047	7446	8566	0	0	4525	1050	4000	10764
2036	3350	900	400	35934	7893	9583	0	0	5725	1050	4000	11537
2037	3350	900	400	38866	8351	10654	0	0	5725	1050	4000	12316
2038	3350	900	400	41824	8820	11777	0	0	5725	1050	4000	13096
2039	3350	900	400	44793	9299	12954	0	0	5725	1050	4000	13871

2040	3350	900	400	47756	9789	14184	0	0	5725	1050	4000	14637
2041	3350	900	400	50695	10290	15467	0	0	6925	1050	4800	15387
2042	3350	900	400	53593	10801	16803	0	0	6925	1050	4800	16117
2043	3350	900	400	56435	11324	18192	0	0	6925	1050	4800	16821
2044	3350	900	400	59203	11856	19634	0	0	6925	1050	4800	17493
2045	3350	900	400	61879	12400	21129	0	0	6925	1050	4800	18129
2046	3350	900	400	64448	12954	22678	0	0	8125	1050	4800	18723
2047	3350	900	400	66892	13519	24279	0	0	8125	1050	4800	19270
2048	3350	900	400	69195	14095	25934	0	0	8125	1050	4800	19764
2049	3350	900	400	71339	14681	27641	0	0	8125	1050	4800	20200
2050	3350	900	400	73308	15278	29402	0	0	8125	1050	4800	20572

Pathway C1

Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Quebec	Imports from NBSO	Imports from NYISO	Storage
2025	3350	900	400	9027	3233	974	0	0	2125	1050	3200	4199
2026	3350	900	400	9027	3233	974	0	0	2125	1050	3200	4199
2027	3350	900	400	9027	3233	974	0	0	2125	1050	3200	4199
2028	3350	900	400	9027	3233	974	0	0	2125	1050	3200	4199
2029	3350	900	400	9027	3233	974	0	0	2125	1050	3200	4199
2030	3350	900	400	9027	3233	974	0	0	2125	1050	3200	4199
2031	3350	900	400	9027	3233	974	2100	0	2125	1050	3200	4199
2032	3350	900	400	9027	3233	974	4200	0	2125	1050	3200	4199
2033	3350	900	400	9027	3233	974	6300	0	2125	1050	3200	4199
2034	3350	900	400	9027	3233	974	8400	0	2125	1050	3200	4199
2035	3350	900	400	9027	3233	974	10500	0	2125	1050	3200	4199
2036	3350	900	400	9027	3233	974	12600	0	2125	1050	3200	4199
2037	3350	900	400	9027	3233	974	14700	0	2125	1050	3200	4199
2038	3350	900	400	9027	3233	974	16800	0	2125	1050	3200	4199

2039	3350	900	400	9027	3233	974	18900	0	2125	1050	3200	4199
2040	3350	900	400	9027	3233	974	21000	0	2125	1050	3200	4199
2041	3350	900	400	9027	3233	974	23100	0	2125	1050	3200	4199
2042	3350	900	400	9027	3233	974	25200	0	2125	1050	3200	4199
2043	3350	900	400	9027	3233	974	27300	0	2125	1050	3200	4199
2044	3350	900	400	9027	3233	974	29400	0	2125	1050	3200	4199
2045	3350	900	400	9027	3233	974	31500	0	2125	1050	3200	4199
2046	3350	900	400	9027	3233	974	33600	0	2125	1050	3200	4199
2047	3350	900	400	9027	3233	974	35700	0	2125	1050	3200	4199
2048	3350	900	400	9027	3233	974	37800	0	2125	1050	3200	4199
2049	3350	900	400	9027	3233	974	39900	0	2125	1050	3200	4199
2050	3350	900	400	9027	3233	974	42000	0	2125	1050	3200	4199

Pathway C2

Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Quebec	Imports from NBSO	Imports from NYISO	Storage
2025	3350	900	400	10315	3563	1471	0	0	2125	1050	3200	4551
2026	3350	900	400	11833	3903	2029	0	0	2125	1050	3200	4968
2027	3350	900	400	13563	4254	2648	0	0	2125	1050	3200	5445
2028	3350	900	400	15490	4615	3327	0	0	2125	1050	3200	5976
2029	3350	900	400	17596	4988	4067	0	0	2125	1050	3200	6556
2030	3350	900	400	19864	5371	4867	0	0	2125	1050	3200	7180
2031	3350	900	400	22277	5764	5728	300	0	2125	1050	4000	7841
2032	3350	900	400	24819	6169	6650	600	0	2125	1050	4000	8536
2033	3350	900	400	27473	6584	7633	900	0	2125	1050	4000	9258
2034	3350	900	400	30221	7010	8676	1200	0	2125	1050	4000	10003
2035	3350	900	400	33047	7446	9780	1500	0	2125	1050	4000	10764
2036	3350	900	400	35934	7893	10944	1800	0	2125	1050	4000	11537
2037	3350	900	400	38866	8351	12169	2100	0	2125	1050	4000	12316

2038	3350	900	400	41824	8820	13455	2400	0	2125	1050	4000	13096
2039	3350	900	400	44793	9299	14801	2700	0	2125	1050	4000	13871
2040	3350	900	400	47756	9789	16209	3000	0	2125	1050	4000	14637
2041	3350	900	400	50695	10290	17676	3300	0	2125	1050	4800	15387
2042	3350	900	400	53593	10801	19205	3600	0	2125	1050	4800	16117
2043	3350	900	400	56435	11324	20794	3900	0	2125	1050	4800	16821
2044	3350	900	400	59203	11856	22444	4200	0	2125	1050	4800	17493
2045	3350	900	400	61879	12400	24154	4200	0	2125	1050	4800	18129
2046	3350	900	400	64448	12954	25925	4200	0	2125	1050	4800	18723
2047	3350	900	400	66892	13519	27757	4200	0	2125	1050	4800	19270
2048	3350	900	400	69195	14095	29650	4200	0	2125	1050	4800	19764
2049	3350	900	400	71339	14681	31603	4200	0	2125	1050	4800	20200
2050	3350	900	400	73308	15278	33617	4200	0	2125	1050	4800	20572

Pathway C3

Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Quebec	Imports from NBSO	Imports from NYISO	Storage
2025	3350	900	400	10315	3563	1311	0	0	2125	1050	3200	4551
2026	3350	900	400	11833	3903	1798	0	0	3325	1050	3200	4968
2027	3350	900	400	13563	4254	2337	0	0	3325	1050	3200	5445
2028	3350	900	400	15490	4615	2930	0	0	3325	1050	3200	5976
2029	3350	900	400	17596	4988	3576	0	0	3325	1050	3200	6556
2030	3350	900	400	19864	5371	4275	0	0	3325	1050	3200	7180
2031	3350	900	400	22277	5764	5027	300	0	4525	1050	4000	7841
2032	3350	900	400	24819	6169	5832	600	0	4525	1050	4000	8536
2033	3350	900	400	27473	6584	6690	900	0	4525	1050	4000	9258
2034	3350	900	400	30221	7010	7601	1200	0	4525	1050	4000	10003
2035	3350	900	400	33047	7446	8566	1500	0	4525	1050	4000	10764
2036	3350	900	400	35934	7893	9583	1800	0	4525	1050	4000	11537

2037	3350	900	400	38866	8351	10654	2100	0	4525	1050	4000	12316
2038	3350	900	400	41824	8820	11777	2100	0	4525	1050	4000	13096
2039	3350	900	400	44793	9299	12954	2100	0	4525	1050	4000	13871
2040	3350	900	400	47756	9789	14184	2100	0	4525	1050	4000	14637
2041	3350	900	400	50695	10290	15467	2100	0	6225	1050	4800	15387
2042	3350	900	400	53593	10801	16803	2100	0	6225	1050	4800	16117
2043	3350	900	400	56435	11324	18192	2100	0	6225	1050	4800	16821
2044	3350	900	400	59203	11856	19634	2100	0	6225	1050	4800	17493
2045	3350	900	400	61879	12400	21129	2100	0	6225	1050	4800	18129
2046	3350	900	400	64448	12954	22678	2100	0	6225	1050	4800	18723
2047	3350	900	400	66892	13519	24279	2100	0	6225	1050	4800	19270
2048	3350	900	400	69195	14095	25934	2100	0	6225	1050	4800	19764
2049	3350	900	400	71339	14681	27641	2100	0	6225	1050	4800	20200
2050	3350	900	400	73308	15278	29402	2100	0	6225	1050	4800	20572

Pathway D

Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Quebec	Imports from NBSO	Imports from NYISO	Storage
2025	3350	900	400	9361	3353	1010	0	0	2125	1050	3200	4551
2026	3350	900	400	9707	3477	1047	0	0	3325	1050	3200	4968
2027	3350	900	400	10066	3606	1086	0	0	3325	1050	3200	5445
2028	3350	900	400	10438	3739	1126	0	0	3325	1050	3200	5976
2029	3350	900	400	10824	3877	1168	0	0	3325	1050	3200	6556
2030	3350	900	400	11224	4020	1211	0	0	3325	1050	3200	7180
2031	3350	900	400	11639	4169	1256	0	0	4525	1050	4000	7841
2032	3350	900	400	12070	4323	1302	0	0	4525	1050	4000	8536
2033	3350	900	400	12517	4483	1350	0	1131	4525	1050	4000	9258
2034	3350	900	400	12980	4649	1400	0	2262	4525	1050	4000	10003
2035	3350	900	400	13460	4821	1452	0	3393	4525	1050	4000	10764

2036	3350	900	400	13958	4999	1506	0	4524	4525	1050	4000	11537
2037	3350	900	400	14474	5184	1562	0	5655	4525	1050	4000	12316
2038	3350	900	400	15010	5376	1620	0	6786	4525	1050	4000	13096
2039	3350	900	400	15565	5575	1680	0	7917	4525	1050	4000	13871
2040	3350	900	400	16141	5781	1742	0	9048	4525	1050	4000	14637
2041	3350	900	400	16738	5995	1806	0	10179	6225	1050	4800	15387
2042	3350	900	400	17357	6217	1873	0	11310	6225	1050	4800	16117
2043	3350	900	400	17999	6447	1942	0	12441	6225	1050	4800	16821
2044	3350	900	400	18665	6686	2014	0	13572	6225	1050	4800	17493
2045	3350	900	400	19356	6933	2089	0	14703	6225	1050	4800	18129
2046	3350	900	400	20072	7190	2166	0	15834	6225	1050	4800	18723
2047	3350	900	400	20815	7456	2246	0	16965	6225	1050	4800	19270
2048	3350	900	400	21585	7732	2329	0	18096	6225	1050	4800	19764
2049	3350	900	400	22384	8018	2415	0	19227	6225	1050	4800	20200
2050	3350	900	400	23212	8315	2504	0	20358	6225	1050	4800	20572

Table S3: Average annual (2022–2050) electricity generation capacity changes under a no Inflation Reduction Act scenario (U.S. EIA AEO, 2023).

Source	**Average annual change in the U.S. (%)**
Coal	-2.7%
Oil and Natural Gas Steam	-1.1%
Combined Cycle (CC)	1.0%
Combustion Turbine/Diesel (CT)	3.1%
Nuclear Power	-0.2%
Pumped Storage	0.0%
Diurnal Storage	6.3%
Fuel Cells	0.7%
Renewable Sources	3.7%
Distributed Generation (Natural Gas)	--
Total	**1.8%**

Table S4: Facility and unit-level operational characteristics, ramp category, retirement timelines, and emissions factors for all fossil fuel power plant facilities in New England. This table includes each facility's nameplate capacity (MW) and capacity factor (in brackets), ramp designation, projected retirement year, and average CO_2, NO_x, SO_2, and heat input rates on a per-MW basis. Note this retirement schedule in this study applies to all pathways except A and D.

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Alfred L Pierce Generating Station	6635 [AP-1]	New Haven County, CT	84 [0.62]	1H	2062	0.63	0.56	0.01	6.29
Bellingham	10307 [1]	Norfolk County, MA	257.4 [0.37]	12H	2046	0.67	0.88	0.03	4.11
Bellingham	10307 [2]	Norfolk County, MA	257.4 [0.37]	12H	2046	0.68	0.92	0.03	4.24
Bellingham Power Generation LLC	55211 [2]	Norfolk County, MA	289 [0.45]	12H	2057	0.65	0.1	0.01	4.9
Bellingham Power Generation LLC	55211 [1]	Norfolk County, MA	289 [0.44]	12H	2057	0.66	0.1	0.01	4.93
Berkshire Power	55041 [1]	Hampden County, MA	289 [0.67]	12H	2054	0.43	0.11	0	4.85
Berlin 5	3734 [A]	Washington County, VT	41.8 [0.89]	10M	2027	0.79	0.12	0.01	13.22
Berlin 5	3734 [B]	Washington County, VT	41.8 [0.89]	10M	2027	0.79	0.12	0.01	13.22
Blackstone Power	55212 [1]	Worcester County, MA	289 [0.44]	12H	2056	0.64	0.1	0.01	4.78

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Generation LLC									
Blackstone Power Generation LLC	55212 [2]	Worcester County, MA	289 [0.45]	12H	2056	0.65	0.09	0.01	4.89
Branford	540 [10]	New Haven County, CT	21.8 [0.53]	10M	2024	0.78	14.91	0.01	7
Bridgeport Energy	55042 [BE1]	Fairfield County, CT	350 [0.62]	12H	2053	0.44	0.13	0	4.55
Bridgeport Energy	55042 [BE2]	Fairfield County, CT	350 [0.64]	12H	2053	0.43	0.13	0	4.57
Bridgeport Harbor Station	568 [BHB5]	Fairfield County, CT	575.6 [0.78]	1H	2074	0.38	0.04	0	5.03
Bridgeport Harbor Station	568 [BHB2]	Fairfield County, CT	179.5 [0.78]	1H	2016	1.02	1.39	3.35	9.95
Burgess BioPower	58054 [ST01]	Coos County, NH	75 [0.94]	OVER	2058	1.52	0.92	0.07	13.69
Canal Station	1599 [2]	Barnstable County, MA	580 [0.35]	12H	2030	0.76	1.49	2.2	3.77
Canal Station	1599 [3]	Barnstable County, MA	367.7 [0.69]	12H	2030	0.6	0.1	0.01	6.62
Canal Station	1599 [1]	Barnstable County, MA	585 [0.53]	12H	2023	0.78	0.98	3.51	5.07
Cleary Flood	1682 [8]	Bristol County, MA	28 [0.61]	10M	2021	1.19	3.87	10.45	9.01

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Cleary Flood	1682 [9]	Bristol County, MA	118 [0.49]	10M	2030	0.63	1.6	0.07	5.15
Cos Cob	542 [10]	Fairfield County, CT	25 [0.56]	10M	2024	0.78	13.5	0.01	6.27
Cos Cob	542 [11]	Fairfield County, CT	25 [0.58]	10M	2024	0.78	13.36	0.01	6.51
Cos Cob	542 [12]	Fairfield County, CT	25 [0.58]	10M	2024	0.78	13.7	0.01	6.58
Cos Cob	542 [14]	Fairfield County, CT	20 [0.72]	10M	2030	0.78	16.34	0.01	10.33
Cos Cob	542 [13]	Fairfield County, CT	20 [0.68]	10M	2030	0.78	18.2	0.01	10.38
CPV Towantic Energy Center	56047 [2]	New Haven County, CT	565.5 [0.62]	12H	2073	0.39	0.04	0	4.1
CPV Towantic Energy Center	56047 [1]	New Haven County, CT	565.5 [0.63]	12H	2073	0.38	0.04	0	4.1
Dartmouth Power	52026 [2]	Bristol County, MA	24.7 [0.7]	12H	2064	0.63	0.13	0.01	7.4
Dartmouth Power	52026 [1]	Bristol County, MA	77 [0.63]	12H	2047	0.48	0.26	0.01	5.06
Devon	544 [10]	New Haven County, CT	18.6 [0.67]	1H	2040	0.78	13.74	0.01	7.67
Devon	544 [14]	New Haven County, CT	43 [0.55]	1H	2051	0.79	8.21	0.18	5.98
Devon	544 [13]	New Haven County, CT	43 [0.56]	1H	2051	0.8	8.41	0.21	6.03
Devon	544 [12]	New Haven County, CT	43 [0.56]	1H	2051	0.78	8.27	0.19	6.07

Facility name	**Facility [unit] ID**	**Location**	**Nameplate capacity (MW) [capacity factor]**	**Ramp**	**Retirement year**	**CO2 tons MW^{-1}**	**NOx lbs. MW^{-1}**	**SO2 lbs. MW^{-1}**	**Heat input MMBtu MW^{-1}**
Devon	544 [11]	New Haven County, CT	43 [0.56]	1H	2051	0.79	8.66	0.2	6.1
Devon	544 [16]	New Haven County, CT	51 [0.72]	1H	2065	0.58	0.11	0.01	5.17
Devon	544 [15]	New Haven County, CT	51 [0.72]	1H	2065	0.58	0.12	0.01	5.22
Devon	544 [18]	New Haven County, CT	51 [0.74]	1H	2065	0.58	0.13	0.01	5.44
Devon	544 [17]	New Haven County, CT	51 [0.75]	1H	2065	0.59	0.11	0.01	5.53
Dighton	55026 [1]	Bristol County, MA	200 [0.74]	12H	2054	0.46	0.1	0	5.72
Exelon West Medway II	59882 [J5]	Norfolk County, MA	131.8 [0.39]	10M	2074	0.55	0.09	0.01	3.62
Exelon West Medway II	59882 [J4]	Norfolk County, MA	131.8 [0.4]	10M	2074	0.55	0.09	0.01	3.69
Fore River Energy Center	55317 [11]	Norfolk County, MA	593.6 [0.53]	OVER	2058	0.42	0.05	0	3.74
Fore River Energy Center	55317 [12]	Norfolk County, MA	593.6 [0.55]	OVER	2058	0.44	0.05	0	4.01
Framingham Station	1586 [FJ-3]	Middlesex County, MA	14.2 [0.41]	10M	2024	0.78	11.86	0.01	8.46
Framingham Station	1586 [FJ-2]	Middlesex County, MA	14.2 [0.4]	10M	2024	0.78	11.18	0.01	8.74
Framingham Station	1586 [FJ-1]	Middlesex County, MA	14.2 [0.43]	10M	2024	0.78	11.44	0.01	8.87
Franklin Drive	561 [10]	Litchfield County, CT	21.8 [0.47]	10M	2024	0.78	18.45	0.01	7.26

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Granite Ridge Energy	55170 [1]	Rockingham County, NH	530 [0.36]	12H	2058	0.64	0.1	0.01	3.9
Granite Ridge Energy	55170 [2]	Rockingham County, NH	530 [0.36]	12H	2058	0.64	0.1	0.01	3.91
J C McNeil	589 [1]	Chittenden County, VT	59.5 [0.82]	OVER	2029	1.48	0.98	0.01	11.55
Kendall Green Energy LLC	1595 [S6]	Middlesex County, MA	20 [0.44]	12H	2025	0.78	23.04	0.01	9.98
Kendall Green Energy LLC	1595 [4]	Middlesex County, MA	253.6 [1.03]	12H	2030	0.39	0.05	0	6.65
Kendall Green Energy LLC	1595 [3]	Middlesex County, MA	54.4 [0.82]	12H	2009	1.47	1.28	8.28	13.57
Kendall Green Energy LLC	1595 [2]	Middlesex County, MA	50.2 [0.87]	12H	2004	1.54	1	0.01	14.75
Kleen Energy Systems Project	56798 [U1]	Middlesex County, CT	494 [0.55]	12H	2066	0.41	0.05	0	3.79
Kleen Energy Systems Project	56798 [U2]	Middlesex County, CT	494 [0.55]	12H	2066	0.41	0.05	0	3.8
Lake Road Generating Company	55149 [LRG3]	Windham County, CT	280 [0.52]	12H	2056	0.66	0.07	0.01	5.75
Lake Road Generating Company	55149 [LRG1]	Windham County, CT	280 [0.51]	12H	2056	0.67	0.08	0.01	5.76

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Lake Road Generating Company	55149 [LRG2]	Windham County, CT	280 [0.52]	12H	2056	0.66	0.08	0.01	5.84
Lost Nation	2362 [CT1]	Coos County, NH	18 [0.42]	10M	2024	0.78	21.48	0.01	14.44
Maine Independence Station	55068 [2]	Penobscot County, ME	371.2 [0.28]	12H	2055	0.7	0.21	0.01	3.33
Maine Independence Station	55068 [1]	Penobscot County, ME	371.2 [0.29]	12H	2055	0.7	0.2	0.01	3.34
Manchester Street Station	3236 [9]	Providence County, RI	171 [0.5]	12H	2050	0.72	0.41	0.01	5.97
Manchester Street Station	3236 [10]	Providence County, RI	173 [0.51]	12H	2050	0.7	0.35	0.01	6.03
Manchester Street Station	3236 [11]	Providence County, RI	171 [0.52]	12H	2050	0.71	0.37	0.01	6.16
MBTA South Boston Power Facility	10176 [B]	Suffolk County, MA	69 [0.4]	10M	2030	0.72	1.41	0.01	3.61
MBTA South Boston Power Facility	10176 [A]	Suffolk County, MA	69 [0.41]	10M	2030	0.71	1.36	0.01	3.61
Medway Station	1592 [J1T1]	Norfolk County, MA	45 [0.24]	1H	2025	1.69	11.23	0.01	4.95
Medway Station	1592 [J1T2]	Norfolk County, MA	45 [0.26]	1H	2025	1.55	10.72	0.01	4.98

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Medway Station	1592 [J2T1]	Norfolk County, MA	45 [0.26]	1H	2025	1.6	9.44	0.01	5.04
Medway Station	1592 [J2T2]	Norfolk County, MA	45 [0.25]	1H	2025	1.63	10.37	0.01	5.04
Medway Station	1592 [J3T2]	Norfolk County, MA	45 [0.28]	1H	2025	1.54	9.75	0.01	5.37
Medway Station	1592 [J3T1]	Norfolk County, MA	45 [0.28]	1H	2025	1.57	10.55	0.01	5.42
Merrimack	2364 [CT2]	Merrimack County, NH	18.6 [0.42]	OVER	2024	0.78	24.04	0.01	12.81
Merrimack	2364 [CT1]	Merrimack County, NH	18.6 [0.43]	OVER	2024	0.78	23.18	0.01	12.88
Merrimack	2364 [1]	Merrimack County, NH	113.6 [0.87]	OVER	2030	1.02	2.77	1.32	8.67
Merrimack	2364 [2]	Merrimack County, NH	345.6 [0.77]	OVER	2030	1.01	2.57	1.53	7.62
Middletown	562 [10]	Middlesex County, CT	18.6 [0.49]	10M	2021	0.78	17.23	0.01	7.87
Middletown	562 [14]	Middlesex County, CT	60.5 [0.58]	10M	2030	0.58	0.05	0.01	4.23
Middletown	562 [15]	Middlesex County, CT	60.5 [0.58]	10M	2030	0.6	0.06	0.01	4.36
Middletown	562 [12]	Middlesex County, CT	60.5 [0.59]	10M	2030	0.59	0.07	0.01	4.43
Middletown	562 [13]	Middlesex County, CT	60.5 [0.59]	10M	2030	0.59	0.06	0.01	4.44
Middletown	562 [2]	Middlesex County, CT	113.6 [0.58]	10M	2013	0.68	1.21	0.54	6.36

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Middletown	562 [3]	Middlesex County, CT	239.4 [0.53]	10M	2019	0.62	2	0.3	5.36
Middletown	562 [4]	Middlesex County, CT	414.9 [0.39]	10M	2028	1.11	3.15	3.64	5.33
Milford Power Company LLC	55126 [CT02]	New Haven County, CT	289 [0.81]	12H	2057	0.42	0.05	0	5.7
Milford Power Company LLC	55126 [CT01]	New Haven County, CT	289 [0.83]	12H	2057	0.42	0.05	0	5.85
Milford Power, LLC	54805 [1]	Worcester County, MA	249.3 [0.45]	1H	2048	0.59	0.3	0.01	4.44
Millennium Power	55079 [1]	Worcester County, MA	360 [0.55]	12H	2055	0.64	0.14	0.01	5.87
Montville	546 [5]	New London County, CT	80.4 [0.59]	10M	2009	0.82	1.46	1.92	6.74
Montville	546 [6]	New London County, CT	414.9 [0.33]	10M	2026	1.05	2.57	3.53	4.24
Mystic	1588 [94]	Middlesex County, MA	593.6 [0.49]	12H	2024	0.43	0.05	0	3.51
Mystic	1588 [93]	Middlesex County, MA	593.6 [0.49]	12H	2024	0.43	0.06	0	3.53
Mystic	1588 [82]	Middlesex County, MA	593.6 [0.51]	12H	2024	0.42	0.06	0	3.62
Mystic	1588 [81]	Middlesex County, MA	593.6 [0.51]	12H	2024	0.42	0.05	0	3.65
New Haven Harbor	6156 [NHHS2]	New Haven County, CT	60.5 [0.59]	OVER	2030	0.58	0.19	0.01	4.36
New Haven Harbor	6156 [NHHS3]	New Haven County, CT	60.5 [0.6]	OVER	2030	0.58	0.15	0.01	4.39

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
New Haven Harbor	6156 [NHHS4]	New Haven County, CT	60.5 [0.6]	OVER	2030	0.58	0.15	0.01	4.4
New Haven Harbor	6156 [NHB1]	New Haven County, CT	460 [0.35]	OVER	2030	0.78	1.19	1.89	3.7
Newington	8002 [1]	Rockingham County, NH	414 [0.35]	OVER	2029	0.95	2.33	4.08	4.54
Newington Energy	55661 [2]	Rockingham County, NH	419.9 [0.48]	12H	2057	0.44	0.1	0.01	3.48
Newington Energy	55661 [1]	Rockingham County, NH	419.9 [0.5]	12H	2057	0.45	0.1	0.01	3.62
Ocean State Power	51030 [2]	Providence County, RI	171.4 [0.41]	12H	2045	0.73	0.34	0.01	5.05
Ocean State Power	51030 [1]	Providence County, RI	171.4 [0.43]	12H	2045	0.71	0.31	0.01	5.06
Ocean State Power II	54324 [3]	Providence County, RI	171.4 [0.4]	12H	2046	0.76	0.35	0.01	5.14
Ocean State Power II	54324 [4]	Providence County, RI	171.4 [0.42]	12H	2046	0.75	0.37	0.01	5.23
Penny Lane Gas Turbine	3754 [CT1]	Chittenden County, VT	25.5 [0.92]	1H	2026	0.78	0.1	0.01	13.17
Penny Lane Gas Turbine	3754 [CT2]	Chittenden County, VT	25.5 [0.92]	1H	2026	0.78	0.1	0.01	13.17
Pittsfield Generating	50002 [1]	Berkshire County, MA	93.4 [0.34]	12H	2045	0.71	0.28	0	3.94
Pittsfield Generating	50002 [3]	Berkshire County, MA	93.4 [0.35]	12H	2045	0.71	0.25	0	4.07
Pittsfield Generating	50002 [2]	Berkshire County, MA	93.4 [0.35]	12H	2045	0.72	0.27	0	4.08

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Potter	1660 [4]	Norfolk County, MA	58 [0.67]	12H	2024	0.53	0.11	0.01	5.6
Potter	1660 [5]	Norfolk County, MA	58 [0.67]	12H	2024	0.53	0.14	0.01	5.62
Potter	1660 [3]	Norfolk County, MA	101 [0.44]	12H	2024	0.74	4.75	0	5.5
Rhode Island State Energy Center	55107 [RISEP2]	Providence County, RI	400 [0.62]	12H	2057	0.4	0.05	0	4.18
Rhode Island State Energy Center	55107 [RISEP1]	Providence County, RI	400 [0.62]	12H	2057	0.4	0.05	0	4.21
Rumford Power	55100 [1]	Oxford County, ME	272.9 [0.64]	12H	2055	0.43	0.16	0	4.7
Ryegate Associates	51026 [1]	Caledonia County, VT	20 [0.95]		2037	1.48	0.55	0.01	14.24
Salem Harbor Station NGCC	60903 [2]	Essex County, MA	399.1 [0.56]	12H	2073	0.41	0.07	0	3.93
Salem Harbor Station NGCC	60903 [1]	Essex County, MA	399.1 [0.56]	12H	2072	0.42	0.06	0	3.97
Schiller	2367 [CT1]	Rockingham County, NH	21.3 [0.4]	12H	2024	0.78	25.56	0.01	13.27
Schiller	2367 [6]	Rockingham County, NH	50 [0.55]	12H	2030	1.23	2.82	9.97	6.7
Schiller	2367 [4]	Rockingham County, NH	50 [0.54]	12H	2027	1.26	3.14	10.77	6.76
Schiller	2367 [5]	Rockingham County, NH	50 [0.87]	12H	2000	1.54	1	0.01	12.79

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Stony Brook Energy Center	6081 [4]	Hampden County, MA	85 [0.48]	10M	2030	1.07	15.82	0.01	6.39
Stony Brook Energy Center	6081 [5]	Hampden County, MA	85 [0.48]	10M	2030	1.1	16.24	0.01	6.55
Stony Brook Energy Center	6081 [2]	Hampden County, MA	190 [0.32]	10M	2030	0.85	1.89	0	3.69
Stony Brook Energy Center	6081 [3]	Hampden County, MA	190 [0.33]	10M	2030	0.77	1.9	0	3.92
Stony Brook Energy Center	6081 [1]	Hampden County, MA	190 [0.34]	10M	2030	0.77	2.02	0	3.97
Tiverton Power, LLC	55048 [1]	Newport County, RI	272.5 [0.83]	12H	2055	0.42	0.08	0	5.82
Torrington Terminal	565 [10]	Litchfield County, CT	21.8 [0.5]	10M	2024	0.78	17.23	0.01	7.23
Wallingford Energy, LLC	55517 [CT01]	New Haven County, CT	50 [0.74]	1H	2056	0.47	0.08	0	5.82
Wallingford Energy, LLC	55517 [CT07]	New Haven County, CT	50 [0.69]	1H	2072	0.5	0.1	0.01	5.83
Wallingford Energy, LLC	55517 [CT02]	New Haven County, CT	50 [0.73]	1H	2056	0.48	0.09	0	5.86
Wallingford Energy, LLC	55517 [CT03]	New Haven County, CT	50 [0.7]	1H	2056	0.5	0.09	0.01	5.86
Wallingford Energy, LLC	55517 [CT05]	New Haven County, CT	50 [0.73]	1H	2056	0.48	0.08	0	5.86
Wallingford Energy, LLC	55517 [CT06]	New Haven County, CT	50 [0.7]	1H	2072	0.51	0.1	0.01	5.97
Wallingford Energy, LLC	55517 [CT04]	New Haven County, CT	50 [0.74]	1H	2056	0.48	0.08	0.01	5.98

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO2 tons MW^{-1}	NOx lbs. MW^{-1}	SO2 lbs. MW^{-1}	Heat input MMBtu MW^{-1}
Waterbury Generation	56629 [10]	New Haven County, CT	96 [0.69]	1H	2064	0.47	0.14	0.02	5.47
Waters River	1678 [1]	Essex County, MA	21.3 [0.68]	1H	2026	0.78	5.47	0.01	7.97
Waters River	1678 [2]	Essex County, MA	49.9 [0.49]	1H	2026	0.75	3.39	0.01	5.64
Waterside Power, LLC	56189 [4]	Fairfield County, CT	23.2 [0.92]	1H	2059	0.78	0.1	0.01	13.17
Waterside Power, LLC	56189 [5]	Fairfield County, CT	23.2 [0.92]	1H	2059	0.78	0.1	0.01	13.17
Waterside Power, LLC	56189 [7]	Fairfield County, CT	23.2 [0.92]	1H	2061	0.78	0.1	0.01	13.17
Westbrook Energy Center	55294 [2]	Cumberland County, ME	379.7 [0.59]	12H	2056	0.38	0.1	0	3.76
Westbrook Energy Center	55294 [1]	Cumberland County, ME	379.7 [0.59]	12H	2056	0.38	0.1	0	3.78
White Lake	2369 [CT1]	Carroll County, NH	18.6 [0.42]	10M	2024	0.78	23.01	0.01	12.95
William F Wyman	1507 [2]	Cumberland County, ME	50 [0.17]	OVER	2013	1.35	3.97	10.65	2.62
William F Wyman	1507 [1]	Cumberland County, ME	50 [0.24]	OVER	2012	1.22	3.45	9.63	3.34
William F Wyman	1507 [3]	Cumberland County, ME	213.6 [0.18]	OVER	2020	0.9	1.6	7.09	1.92
William F Wyman	1507 [4]	Cumberland County, ME	649.1 [0.35]	OVER	2030	0.87	1.75	6.52	3.54

Table S5: Externally derived parameters for the generation expansion model

Description	Probabilistic treatment	Calculation method or source
Hourly electricity demand through 2050	Deterministic	Data provided by ISO-NE (Commonwealth of Massachusetts, 2020).
Hourly nuclear, hydropower and biomass capacity factors	Deterministic	Data provided by ISO-NE (Commonwealth of Massachusetts, 2020).
Solar PV, onshore wind and offshore wind capacity factors	Modeled distributions (1st to 99th percentiles)	Non-parametric bootstrap sample year provided by ISO-NE (2024a).; linear regression employed to compute missing percentiles ranging from 1 to 99 .
Energy storage operating constrains	Deterministic	Data provided by ISO-NE (Commonwealth of Massachusetts, 2020).
Hourly electricity imports from other jurisdictions	Empirical distributions (1st to 99th percentiles)	Empirical distributions for percentiles ranging from 1 to 99 were simulated using historical data provided by ISO-NE (2024b).
Fossil fuel facility data (e.g., nameplate capacity, stack heights, age and planned retirements)	Deterministic	Data provided by U.S. EPA CAMPD API. eGrid and EIA Form 860 were consulted to cross reference CAMPD data. (U.S. EIA 860, 2023; U.S. EPA CAMPD, 2024; U.S. EPA eGrid, 2022).
Fossil fuel hourly generation data	Empirical distributions (1st to 99th percentiles)	Empirical distributions for percentiles ranging from 1 to 99 were simulated using historical data provided by U.S. EPA CAMPD (2024).
	Uniform distributions from available estimates	Where historical data were unavailable, data were pooled from comparable facility types within the U.S. EPA CAMPD.
Fossil fuel hourly emissions data (CO_2, SO_2 and NO_x)	Empirical distributions (1st to 99th percentiles)	Empirical distributions for percentiles ranging from 1 to 99 were simulated using historical data provided by U.S. EPA CAMPD (2024).
	Uniform distributions from available estimates	Where historical data were unavailable, data were pooled from comparable facility types within the U.S. EPA CAMPD.

Table S6: Externally derived parameters for cost calculations

Description	**Probabilistic treatment**	**Calculation method or source**	**Location in the manuscript**
CAPEX, FOM and VOM costs	Uniform distributions from available estimates	Data provided by NREL (2024).	SI section 2.8
Fossil generation fuel costs	Uniform distributions from available estimates	Data provided by NREL (2021).	SI section 2.8
Non-fossil generation fuel costs	Uniform distributions from available estimates	Data provided by NREL (2024).	SI section 2.8
Electricity import costs	Uniform distributions from available estimates	Imports from Canada provided by Calder et al., (2022) and imports from NYISO provided by DeSantis et al., (2021).	SI section 2.9
GHG (CO_2, CH_4 and N_2O) emissions economic valuation	Uniform distributions from available estimates	Data provided by Calder et al., (2022).	SI section 2.10
GHG (CH_4 and N_2O) emission factors	Uniform distributions from available estimates	Data provided by U.S. EPA GHGRP (2024) to identify the $CO2_{eq}$ of CH_4 and N_2O emissions for different fuel type.	SI section 2.10
Air emissions (SO_2, NO_X, VOC, $PM_{2.5}$ and PM_{10}) economic valuation	Deterministic valuations based on stack height and county	Data provided by AP3 model (Muller, 2022).	SI section 2.11
CO emissions economic valuation	Uniform distributions from available estimates	Data provided by Calder et al., (2022).	SI section 2.11
Ambient air pollutant (CO, TPM and VOC) emission factors	Uniform distributions from available estimates	EIA 923 (2023) data was pooled to calculate TPM for each facility and U.S. EPA AP-42 (2024) guidelines were used to estimate VOC and CO emissions.	SI section 2.11
Unmet demand penalty	Deterministic	EVOLL model used by ISO-NE (Potomac Economics, 2024).	SI section 2.12
New hydroelectric dam in Canada emission factors and costs	Uniform distributions from available estimates	CAPEX was estimated using (Commonwealth of Massachusetts, 2020; Hollmann et al., 2014). FOM was estimate using IEA (2010). CH_4 emissions were estimated using Delwiche et al., (2022) and Canadian dams as a reference.	SI section 5
CPI factors	Deterministic	Data provided by U.S. Bureau of Labor Statistics (2024) API.	SI section 2.15

Table S7: Summary of fuel-specific emission factors, including non-biogenic CO_2-eq for CH_4 and N_2O emissions, PM rates and ratios, and estimated CO and VOC emissions. Details on sources for these estimates is provided in SI Table S6.

Fuel category	**non-biogenic CH_4-to-CO_2 (ratio %)**	**non-biogenic N_2O-to-CO_2 (ratio %)**	**PM (lbs $MMBtu^{-1}$)**	**$PM_{2.5}$-to-PM (ratio %)**	**PM_{10}-to-PM (ratio %)**	**CO (tons $MMBtu^{-1}$)**	**VOC (tons $MMBtu^{-1}$)**
Oil	9.66E-04	2.62E-03	2.45E-02	69%	31%	1.67E-05	4.29E-06
Gas (combined cycle)	4.91E-04	6.55E-04	1.09E-02	100%	0%	1.50E-05	1.05E-06
Gas (combustion turbine)	5.26E-04	7.27E-04	1.71E-02	100%	0%	1.50E-05	1.05E-06
Coal	3.13E-03	5.48E-03	1.09E-02	32.5%	67.5%	9.62E-06	1.09E-06
Wood	n/a	n/a	2.94E-03	100%	0%	3.00E-04	8.50E-06

Table S8: Facility specific social costs of air emissions (2024-USD tonne^{-1}). Details on sources for these estimates is provided in SI Table S7.

					Social cost (2024-USD tonne^{-1})					
Facility name	**Facility [unit] ID**	**Location**	**Primary fuel type**	**Stack height (ft)**	**NO_x**	**SO_2**	**VOC**	**CO**	**$PM_{2.5}$**	**PM_{10}**
Alfred L Pierce Generating Station	6635 [AP-1]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Bellingham	10307 [1]	Norfolk, MA	Pipeline Natural Gas	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Bellingham	10307 [2]	Norfolk, MA	Pipeline Natural Gas	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Bellingham Power Generation LLC	55211 [1]	Norfolk, MA	Pipeline Natural Gas	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Bellingham Power Generation LLC	55211 [2]	Norfolk, MA	Pipeline Natural Gas	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Berkshire Power	55041 [1]	Hampden, MA	Pipeline Natural Gas	120	77.34	2306.45	765.51	1048.7	6613.95	1070.92
Blackstone Power Generation LLC	55212 [1]	Worcester, MA	Pipeline Natural Gas	120	45.61	4620.84	1455.66	2098.57	12803.49	2135.9

Facility name	Facility [unit] ID	Location	Primary fuel type	Stack height (ft)	Social cost (2024-USD tonne^{-1})					
					NO_x	SO_2	VOC	CO	$PM_{2.5}$	PM_{10}
Blackstone Power Generation LLC	55212 [2]	Worcester, MA	Pipeline Natural Gas	120	45.61	4620.84	1455.66	2098.57	12803.49	2135.9
Bridgeport Energy	55042 [BE1]	Fairfield, CT	Pipeline Natural Gas	120	255.83	4616.87	1786.86	2096.77	15996.44	2298.52
Bridgeport Energy	55042 [BE2]	Fairfield, CT	Pipeline Natural Gas	120	255.83	4616.87	1786.86	2096.77	15996.44	2298.52
Bridgeport Harbor Station	568 [BHB5]	Fairfield, CT	Pipeline Natural Gas	298	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Burgess BioPower	58054 [ST01]	Coos, NH	Wood	120	65.45	938.05	160.64	427.95	1245.45	202.29
Canal Station	1599 [2]	Barnstable, MA	Residual Oil	498	277.65	1021.34	243.93	465.73	1572.67	212.2
Canal Station	1599 [3]	Barnstable, MA	Pipeline Natural Gas	498	277.65	1021.34	243.93	465.73	1572.67	212.2
Cleary Flood	1682 [9]	Bristol, MA	Pipeline Natural Gas	187	93.21	2980.74	1021.34	1354.57	9057.24	1346.59
Cos Cob	542 [13]	Litchfield, CT	Other Oil	120	144.77	4273.78	1437.82	1941.13	12839.19	1733.31
Cos Cob	542 [14]	Litchfield, CT	Other Oil	120	144.77	4273.78	1437.82	1941.13	12839.19	1733.31

Facility name	Facility [unit] ID	Location	Primary fuel type	Stack height (ft)	Social cost (2024-USD tonne^{-1}) NO_x	SO_2	VOC	CO	$PM_{2.5}$	PM_{10}
CPV Towantic Energy Center	56047 [1]	New Haven, CT	Pipeline Natural Gas	150	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
CPV Towantic Energy Center	56047 [2]	New Haven, CT	Pipeline Natural Gas	150	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Dartmouth Power	52026 [1]	Bristol, MA	Pipeline Natural Gas	120	93.21	2980.74	1021.34	1354.57	9057.24	1346.59
Dartmouth Power	52026 [2]	Bristol, MA	Pipeline Natural Gas	120	93.21	2980.74	1021.34	1354.57	9057.24	1346.59
Devon	544 [10]	Fairfield, CT	Other Oil	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Devon	544 [11]	Fairfield, CT	Pipeline Natural Gas	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Devon	544 [12]	Fairfield, CT	Pipeline Natural Gas	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Devon	544 [13]	Fairfield, CT	Pipeline Natural Gas	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Devon	544 [14]	Fairfield, CT	Pipeline Natural Gas	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5

					Social cost (2024-USD tonne^{-1})					
Facility name	**Facility [unit] ID**	**Location**	**Primary fuel type**	**Stack height (ft)**	**NO_x**	**SO_2**	**VOC**	**CO**	**$PM_{2.5}$**	**PM_{10}**
Devon	544 [15]	Fairfield, CT	Diesel Oil	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Devon	544 [16]	Fairfield, CT	Diesel Oil	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Devon	544 [17]	Fairfield, CT	Diesel Oil	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Devon	544 [18]	Fairfield, CT	Diesel Oil	340	27.76	2389.75	840.87	1086.48	6970.92	1003.5
Dighton	55026 [1]	Bristol, MA	Pipeline Natural Gas	120	93.21	2980.74	1021.34	1354.57	9057.24	1346.59
Exelon West Medway II	59882 [J4]	Norfolk, MA	Pipeline Natural Gas	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Exelon West Medway II	59882 [J5]	Norfolk, MA	Pipeline Natural Gas	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Fore River Energy Center	55317 [11]	Norfolk, MA	Pipeline Natural Gas	255	49.58	2010.96	654.45	914.65	5310.99	811.13
Fore River Energy Center	55317 [12]	Norfolk, MA	Pipeline Natural Gas	255	49.58	2010.96	654.45	914.65	5310.99	811.13
Granite Ridge Energy	55170 [1]	Hillsborough, NH	Pipeline Natural Gas	120	77.34	3058.08	795.26	1389.66	6828.13	1189.92
Granite Ridge Energy	55170 [2]	Hillsborough, NH	Pipeline Natural Gas	120	77.34	3058.08	795.26	1389.66	6828.13	1189.92

					Social cost (2024-USD tonne^{-1})					
Facility name	**Facility [unit] ID**	**Location**	**Primary fuel type**	**Stack height (ft)**	**NO_x**	**SO_2**	**VOC**	**CO**	**$PM_{2.5}$**	**PM_{10}**
J C McNeil	589 [1]	Chittenden, VT	Wood	120	63.46	997.55	226.08	454.94	1743.23	311.36
Kendall Green Energy LLC	1595 [4]	Middlesex, MA	Pipeline Natural Gas	120	107.09	5289.18	1889.98	2401.74	16980.1	2718.96
Kendall Green Energy LLC	1595 [S6]	Middlesex, MA	Diesel Oil	120	107.09	5289.18	1889.98	2401.74	16980.1	2718.96
Kleen Energy Systems Project	56798 [U1]	Middlesex, CT	Pipeline Natural Gas	215	69.41	1897.92	592.97	863.37	5154.32	763.53
Kleen Energy Systems Project	56798 [U2]	Middlesex, CT	Pipeline Natural Gas	215	69.41	1897.92	592.97	863.37	5154.32	763.53
Lake Road Generating Company	55149 [LRG1]	Windham, CT	Pipeline Natural Gas	120	148.74	2901.41	767.5	1318.59	6689.31	1068.94
Lake Road Generating Company	55149 [LRG2]	Windham, CT	Pipeline Natural Gas	120	148.74	2901.41	767.5	1318.59	6689.31	1068.94
Lake Road Generating Company	55149 [LRG3]	Windham, CT	Pipeline Natural Gas	120	148.74	2901.41	767.5	1318.59	6689.31	1068.94
Maine Independence Station	55068 [1]	Penobscot, ME	Pipeline Natural Gas	120	29.75	374.82	57.51	172.45	412.5	71.39
Maine Independence Station	55068 [2]	Penobscot, ME	Pipeline Natural Gas	120	29.75	374.82	57.51	172.45	412.5	71.39

Facility name	Facility [unit] ID	Location	Primary fuel type	Stack height (ft)	Social cost (2024-USD tonne^{-1}) NO$_x$	SO$_2$	VOC	CO	PM$_{2.5}$	PM$_{10}$
Manchester Street Station	3236 [10]	Providence, RI	Pipeline Natural Gas	120	113.04	3143.36	1118.52	1428.34	9824.74	1642.08
Manchester Street Station	3236 [11]	Providence, RI	Pipeline Natural Gas	120	113.04	3143.36	1118.52	1428.34	9824.74	1642.08
Manchester Street Station	3236 [9]	Providence, RI	Pipeline Natural Gas	120	113.04	3143.36	1118.52	1428.34	9824.74	1642.08
MBTA South Boston Power Facility	10176 [A]	Suffolk, MA	Other Oil	120	93.21	3716.5	1753.14	1688.33	15883.39	2427.43
MBTA South Boston Power Facility	10176 [B]	Suffolk, MA	Other Oil	120	93.21	3716.5	1753.14	1688.33	15883.39	2427.43
Medway Station	1592 [J1T1]	Norfolk, MA	Diesel Oil	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Medway Station	1592 [J1T2]	Norfolk, MA	Diesel Oil	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Medway Station	1592 [J2T1]	Norfolk, MA	Diesel Oil	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Medway Station	1592 [J2T2]	Norfolk, MA	Diesel Oil	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Medway Station	1592 [J3T1]	Norfolk, MA	Diesel Oil	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Medway Station	1592 [J3T2]	Norfolk, MA	Diesel Oil	120	97.18	3639.16	1503.26	1653.25	13582.89	2084.34
Merrimack	2364 [1]	Merrimack, NH	Coal	445	243.93	1483.43	362.92	675.35	2572.2	414.49

Facility name	Facility [unit] ID	Location	Primary fuel type	Stack height (ft)	Social cost (2024-USD tonne^{-1})					
					NO_x	SO_2	VOC	CO	$PM_{2.5}$	PM_{10}
Merrimack	2364 [2]	Merrimack, NH	Coal	445	243.93	1483.43	362.92	675.35	2572.2	414.49
Middletown	562 [12]	Middlesex, CT	Diesel Oil	266	251.87	1223.63	351.03	557.5	2500.81	374.82
Middletown	562 [13]	Middlesex, CT	Diesel Oil	266	251.87	1223.63	351.03	557.5	2500.81	374.82
Middletown	562 [14]	Middlesex, CT	Diesel Oil	266	251.87	1223.63	351.03	557.5	2500.81	374.82
Middletown	562 [15]	Middlesex, CT	Diesel Oil	266	251.87	1223.63	351.03	557.5	2500.81	374.82
Middletown	562 [4]	Middlesex, CT	Residual Oil	266	251.87	1223.63	351.03	557.5	2500.81	374.82
Milford Power Company LLC	55126 [CT01]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Milford Power Company LLC	55126 [CT02]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Milford Power, LLC	54805 [1]	Worcester, MA	Pipeline Natural Gas	120	45.61	4620.84	1455.66	2098.57	12803.49	2135.9
Millennium Power	55079 [1]	Worcester, MA	Pipeline Natural Gas	120	45.61	4620.84	1455.66	2098.57	12803.49	2135.9
Montville	546 [6]	New London, CT	Residual Oil	249	148.74	3270.29	928.13	1485.92	8053.75	1253.38

					Social cost (2024-USD tonne^{-1})					
Facility name	**Facility [unit] ID**	**Location**	**Primary fuel type**	**Stack height (ft)**	**NO$_x$**	**SO$_2$**	**VOC**	**CO**	**PM$_{2.5}$**	**PM$_{10}$**
New Haven Harbor	6156 [NHB1]	New Haven, CT	Residual Oil	389	339.13	1659.93	521.58	755.42	4077.45	563.23
New Haven Harbor	6156 [NHHS2]	New Haven, CT	Diesel Oil	389	339.13	1659.93	521.58	755.42	4077.45	563.23
New Haven Harbor	6156 [NHHS3]	New Haven, CT	Diesel Oil	389	339.13	1659.93	521.58	755.42	4077.45	563.23
New Haven Harbor	6156 [NHHS4]	New Haven, CT	Diesel Oil	389	339.13	1659.93	521.58	755.42	4077.45	563.23
Newington	8002 [1]	Rockingham, NH	Residual Oil	410	160.64	1495.33	442.25	680.75	3323.83	517.61
Newington Energy	55661 [1]	Rockingham, NH	Pipeline Natural Gas	150	69.41	2812.17	872.6	1278.1	7674.96	1209.75
Newington Energy	55661 [2]	Rockingham, NH	Pipeline Natural Gas	150	69.41	2812.17	872.6	1278.1	7674.96	1209.75
Ocean State Power	51030 [1]	Providence, RI	Pipeline Natural Gas	120	113.04	3143.36	1118.52	1428.34	9824.74	1642.08
Ocean State Power	51030 [2]	Providence, RI	Pipeline Natural Gas	120	113.04	3143.36	1118.52	1428.34	9824.74	1642.08
Ocean State Power II	54324 [3]	Providence, RI	Pipeline Natural Gas	120	113.04	3143.36	1118.52	1428.34	9824.74	1642.08
Ocean State Power II	54324 [4]	Providence, RI	Pipeline Natural Gas	120	113.04	3143.36	1118.52	1428.34	9824.74	1642.08

					Social cost (2024-USD tonne^{-1})					
Facility name	**Facility [unit] ID**	**Location**	**Primary fuel type**	**Stack height (ft)**	**NO_x**	**SO_2**	**VOC**	**CO**	**$PM_{2.5}$**	**PM_{10}**
Pittsfield Generating	50002 [1]	Berkshire, MA	Pipeline Natural Gas	120	105.11	2193.41	624.71	997.42	5269.34	777.41
Pittsfield Generating	50002 [2]	Berkshire, MA	Pipeline Natural Gas	120	105.11	2193.41	624.71	997.42	5269.34	777.41
Pittsfield Generating	50002 [3]	Berkshire, MA	Pipeline Natural Gas	120	105.11	2193.41	624.71	997.42	5269.34	777.41
Rhode Island State Energy Center	55107 [RISEP1]	Providence, RI	Pipeline Natural Gas	185	113.04	3143.36	1118.52	1428.34	9824.74	1642.08
Rhode Island State Energy Center	55107 [RISEP2]	Providence, RI	Pipeline Natural Gas	185	113.04	3143.36	1118.52	1428.34	9824.74	1642.08
Rumford Power	55100 [1]	Oxford, ME	Pipeline Natural Gas	120	77.34	967.8	164.61	441.44	1336.67	210.22
Salem Harbor Station NGCC	60903 [1]	Essex, MA	Pipeline Natural Gas	230	69.41	2322.32	874.59	1055.89	7760.23	1183.97
Salem Harbor Station NGCC	60903 [2]	Essex, MA	Pipeline Natural Gas	230	69.41	2322.32	874.59	1055.89	7760.23	1183.97
Schiller	2367 [4]	Rockingham, NH	Coal	226	69.41	2812.17	872.6	1278.1	7674.96	1209.75

					Social cost (2024-USD tonne^{-1})					
Facility name	**Facility [unit] ID**	**Location**	**Primary fuel type**	**Stack height (ft)**	**NO_x**	**SO_2**	**VOC**	**CO**	**$PM_{2.5}$**	**PM_{10}**
Schiller	2367 [6]	Rockingham, NH	Coal	226	69.41	2812.17	872.6	1278.1	7674.96	1209.75
Stony Brook Energy Center	6081 [1]	Hampden, MA	Pipeline Natural Gas	120	77.34	2306.45	765.51	1048.7	6613.95	1070.92
Stony Brook Energy Center	6081 [2]	Hampden, MA	Pipeline Natural Gas	120	77.34	2306.45	765.51	1048.7	6613.95	1070.92
Stony Brook Energy Center	6081 [3]	Hampden, MA	Pipeline Natural Gas	120	77.34	2306.45	765.51	1048.7	6613.95	1070.92
Stony Brook Energy Center	6081 [4]	Hampden, MA	Diesel Oil	120	77.34	2306.45	765.51	1048.7	6613.95	1070.92
Stony Brook Energy Center	6081 [5]	Hampden, MA	Diesel Oil	120	77.34	2306.45	765.51	1048.7	6613.95	1070.92
Tiverton Power, LLC	55048 [1]	Newport, RI	Pipeline Natural Gas	120	97.18	2231.09	763.53	1014.51	6578.25	981.68
Wallingford Energy, LLC	55517 [CT01]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Wallingford Energy, LLC	55517 [CT02]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Wallingford Energy, LLC	55517 [CT03]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32

					Social cost (2024-USD tonne^{-1})					
Facility name	**Facility [unit] ID**	**Location**	**Primary fuel type**	**Stack height (ft)**	**NO_x**	**SO_2**	**VOC**	**CO**	**$PM_{2.5}$**	**PM_{10}**
Wallingford Energy, LLC	55517 [CT04]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Wallingford Energy, LLC	55517 [CT05]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Wallingford Energy, LLC	55517 [CT06]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Wallingford Energy, LLC	55517 [CT07]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Waterbury Generation	56629 [10]	New Haven, CT	Pipeline Natural Gas	120	85.28	3095.76	1152.24	1406.75	10322.52	1378.32
Waters River	1678 [1]	Essex, MA	Pipeline Natural Gas	120	69.41	2322.32	874.59	1055.89	7760.23	1183.97
Waters River	1678 [2]	Essex, MA	Pipeline Natural Gas	120	69.41	2322.32	874.59	1055.89	7760.23	1183.97
Westbrook Energy Center	55294 [1]	Cumberland, ME	Pipeline Natural Gas	120	101.14	1447.73	329.21	659.16	2784.4	444.24
Westbrook Energy Center	55294 [2]	Cumberland, ME	Pipeline Natural Gas	120	101.14	1447.73	329.21	659.16	2784.4	444.24
William F Wyman	1507 [4]	Cumberland, ME	Residual Oil	320	243.93	926.15	220.13	422.55	1330.72	210.22

Table S9: Methane emissions from Canadian reservoirs and relevant facilities. Total reservoir capacity 7,892 MW and hydroelectric capacity factor of 65%. Details on sources for these estimates is provided in SI Table S5.

Reservoir	**Facility**	**Emissions [mg CH_4-C $(m^2 day)^{-1}$]**	**Area (km^2)**	**Emissions [mg CH_4-C $(day)^{-1}$]**	**Capacity (MW)**	**Emissions [mg CH_4-C (MW $day)^{-1}$]**	**Emissions [mg CH_4-C (MW $year)^{-1}$]**	**Emissions [kg CH_4-C $(MWh)^{-1}$]**
Eastmain Reservoir	Eastmain-1	9.43	602.9	5.69E9	480	4.07E6	714.22	**0.26**
	Eastmain-1-A				768			
	Sarcelle				150			
Laforge-1 Reservoir	Laforge-1	13	1,288	1.67E10	878	1.91E7	3349.24	**1.22**
Robert-Bourassa Reservoir	Robert-Bourassa	5	2,835	1.42E10	5,616	2.52E6	443.28	**0.16**

Table S10: Net present value of costs (in billions of 2024 USD, discounted at 1.5%) across eight decarbonization pathways (A, B1, B2, B3(1), B3(2), C1, C2, C3, D). Costs are disaggregated into capital expenditures (CAPEX), fixed and variable operations and maintenance (O&M), fuel, imports, greenhouse gas (GHG) and air emissions, and unmet demand penalties; values in parentheses indicate uncertainty ranges, and the "Sum" row shows total costs. Pathway B3 compares two cost-accounting methods for new hydroelectric development in Canada: B3(1) assumes U.S.-only costs (infrastructure plus imported power), while B3(2) captures total social costs by also accounting for generation-side impacts (e.g., reservoir methane emissions). Upper and lower bounds in brackets show the 90% CI considering NREL cost various scenarios.

	A	**B1**	**B2**	**B3(1)**	**B3(2)**	**C1**	**C2**	**C3**	**D**
CAPEX	0 (0-0)	200.89 (159.72-248.41)	225.98 (179.33-279.84)	189.21 (150.58-233.78)	238.76 (179.99-303.47)	226.19 (114.01-342.26)	223.33 (170.27-283.01)	202.96 (157.74-254.17)	79.95 (67.23-94.83)
Fixed O&M	46.38 (40.76-51.44)	79.56 (67.56-91.97)	85.24 (72.66-98.35)	76.94 (65.21-89.03)	131.65 (87.31-176.36)	90.88 (72.59-115.43)	86.21 (72.57-101.15)	81.22 (68.43-94.94)	63.84 (54.9-72.77)
Variable O&M	7.71 (7.27-8.11)	3.59 (3.21-3.93)	3.93 (3.55-4.27)	3.59 (3.21-3.93)	3.59 (3.21-3.93)	10.23 (8.98-11.25)	4.65 (4.16-5.08)	4.01 (3.56-4.4)	9.2 (8.73-9.63)
Fuel	53.73 (53.73-53.73)	21.79 (21.79-21.79)	25.56 (25.56-25.56)	21.72 (21.72-21.72)	21.72 (21.72-21.72)	50.02 (47.31-52.81)	27.55 (27.2-27.91)	22.61 (22.38-22.84)	74.58 (74.58-74.58)
Imports	21.88 (10.97-32.8)	74.49 (37.4-111.59)	28.26 (14.15-42.37)	94.7 (47.56-141.84)	17.84 (8.91-26.76)	21.88 (10.97-32.8)	28.26 (14.15-42.37)	74.49 (37.4-111.59)	74.49 (37.4-111.59)
GHG emissions	629.96 (629.96-629.96)	197.62 (197.62-197.62)	237.72 (237.72-237.72)	196.72 (196.72-196.72)	204.07 (198.37-209.76)	192.35 (192.35-192.35)	218.75 (218.75-218.75)	181.3 (181.3-181.3)	780.83 (780.83-780.83)
Air emissions	1.45 (1.45-1.45)	0.68 (0.68-0.68)	0.78 (0.78-0.78)	0.67 (0.67-0.67)	0.67 (0.67-0.67)	0.62 (0.62-0.62)	0.73 (0.73-0.73)	0.63 (0.63-0.63)	1.35 (1.35-1.35)
Unmet demand penalty	488.85 (488.85-488.85)	5.39 (5.39-5.39)	11.97 (11.97-11.97)	4.56 (4.56-4.56)	4.56 (4.56-4.56)	5.52 (5.52-5.52)	6.81 (6.81-6.81)	3.23 (3.23-3.23)	2.34 (2.34-2.34)
Sum	1249.95 (1232.98-1266.33)	584.01 (493.37-681.37)	619.44 (545.73-700.85)	588.11 (490.23-692.25)	622.86 (504.75-747.23)	597.68 (452.36-753.03)	596.28 (514.64-685.8)	570.46 (474.68-673.11)	1086.59 (1027.37-1147.93)

Table S11: Net present value of costs (in billions of 2024 USD, discounted at 2%) across eight decarbonization pathways

	A	**B1**	**B2**	**B3(1)**	**B3(2)**	**C1**	**C2**	**C3**	**D**
CAPEX	0 (0-0)	188.41 (149.78-232.99)	211.75 (167.98-262.31)	177.49 (141.26-219.29)	226.35 (170.26-288.03)	210.25 (106.23-317.81)	209.44 (159.68-265.42)	190.63 (148.12-238.77)	74.75 (62.84-88.67)
Fixed O&M	43.57 (38.34-48.29)	73.9 (62.84-85.34)	79.11 (67.52-91.18)	71.5 (60.68-82.64)	122.33 (81.22-163.77)	83.89 (67.14-106.33)	79.97 (67.4-93.71)	75.43 (63.64-88.07)	59.56 (51.3-67.82)
Variable O&M	7.23 (6.82-7.6)	3.41 (3.06-3.72)	3.73 (3.38-4.05)	3.41 (3.06-3.72)	3.41 (3.06-3.72)	9.47 (8.34-10.41)	4.39 (3.94-4.78)	3.79 (3.38-4.16)	8.56 (8.12-8.95)
Fuel	50.33 (50.33-50.33)	20.8 (20.8-20.8)	24.33 (24.33-24.33)	20.76 (20.76-20.76)	20.76 (20.76-20.76)	46.72 (44.25-49.25)	26.18 (25.86-26.51)	21.54 (21.34-21.76)	69.01 (69.01-69.01)
Imports	20.58 (10.31-30.84)	69 (34.64-103.36)	26.42 (13.23-39.6)	87.3 (43.84-130.75)	16.62 (8.3-24.93)	20.58 (10.31-30.84)	26.42 (13.23-39.6)	69 (34.64-103.36)	69 (34.64-103.36)
GHG emissions	369.28 (369.28-369.28)	116.5 (116.5-116.5)	139.91 (139.91-139.91)	116.03 (116.03-116.03)	121.34 (117.22-125.46)	114.03 (114.03-114.03)	129.01 (129.01-129.01)	107.04 (107.04-107.04)	455.51 (455.51-455.51)
Air emissions	1.35 (1.35-1.35)	0.65 (0.65-0.65)	0.74 (0.74-0.74)	0.64 (0.64-0.64)	0.64 (0.64-0.64)	0.6 (0.6-0.6)	0.7 (0.7-0.7)	0.61 (0.61-0.61)	1.27 (1.27-1.27)
Unmet demand penalty	443.32 (443.32-443.32)	4.98 (4.98-4.98)	11.04 (11.04-11.04)	4.22 (4.22-4.22)	4.22 (4.22-4.22)	5.3 (5.3-5.3)	6.32 (6.32-6.32)	2.99 (2.99-2.99)	2.2 (2.2-2.2)
Sum	935.67 (919.77-951.02)	477.64 (393.24-568.33)	497.04 (428.14-573.17)	481.34 (390.49-578.06)	515.68 (405.69-631.53)	490.84 (356.19-634.58)	482.42 (406.13-566.05)	471.03 (381.75-566.74)	739.86 (684.9-796.79)

Table S12: Net present value of costs (in billions of 2024 USD, discounted at 2.5%) across eight decarbonization pathways

	A	B1	B2	B3(1)	B3(2)	C1	C2	C3	D
CAPEX	0 (0-0)	176.98 (140.69-218.89)	198.74 (157.61-246.27)	166.75 (132.73-206.03)	214.95 (161.33-273.83)	195.66 (99.08-295.45)	196.71 (149.98-249.29)	179.32 (139.31-224.63)	69.99 (58.83-83.03)
Fixed O&M	41 (36.12-45.4)	68.76 (58.54-79.31)	73.54 (62.84-84.67)	66.55 (56.56-76.84)	113.85 (75.67-152.32)	77.56 (62.19-98.1)	74.3 (62.71-86.95)	70.17 (59.28-81.82)	55.67 (48.02-63.3)
Variable O&M	6.79 (6.41-7.13)	3.24 (2.92-3.53)	3.55 (3.22-3.84)	3.25 (2.92-3.54)	3.25 (2.92-3.54)	8.79 (7.75-9.65)	4.15 (3.73-4.52)	3.6 (3.21-3.93)	7.97 (7.57-8.34)
Fuel	47.23 (47.23-47.23)	19.87 (19.87-19.87)	23.2 (23.2-23.2)	19.85 (19.85-19.85)	19.85 (19.85-19.85)	43.71 (41.47-46.02)	24.91 (24.61-25.21)	20.56 (20.37-20.75)	63.96 (63.96-63.96)
Imports	19.38 (9.72-29.05)	64.02 (32.14-95.9)	24.74 (12.39-37.09)	80.6 (40.48-120.73)	15.51 (7.75-23.27)	19.38 (9.72-29.05)	24.74 (12.39-37.09)	64.02 (32.14-95.9)	64.02 (32.14-95.9)
GHG emissions	226.1 (226.1-226.1)	71.74 (71.74-71.74)	86.01 (86.01-86.01)	71.48 (71.48-71.48)	75.52 (72.39-78.64)	70.62 (70.62-70.62)	79.47 (79.47-79.47)	66.01 (66.01-66.01)	277.48 (277.48-277.48)
Air emissions	1.27 (1.27-1.27)	0.62 (0.62-0.62)	0.71 (0.71-0.71)	0.62 (0.62-0.62)	0.62 (0.62-0.62)	0.58 (0.58-0.58)	0.67 (0.67-0.67)	0.58 (0.58-0.58)	1.2 (1.2-1.2)
Unmet demand penalty	402.36 (402.36-402.36)	4.6 (4.6-4.6)	10.2 (10.2-10.2)	3.91 (3.91-3.91)	3.91 (3.91-3.91)	5.09 (5.09-5.09)	5.88 (5.88-5.88)	2.77 (2.77-2.77)	2.06 (2.06-2.06)
Sum	744.13 (729.21-758.54)	409.84 (331.12-494.46)	420.69 (356.17-492)	413.03 (328.56-503)	447.47 (344.45-555.99)	421.39 (296.49-554.56)	410.82 (339.44-489.08)	407.02 (323.66-496.39)	542.35 (491.26-595.27)

Table S13: Net present value of costs (billions of 2024 USD, discounted at 2%) for All-Options Pathway, as estimated by ISO-NE's Massachusetts Decarbonization Roadmap study (Commonwealth of Massachusetts, 2020). We excluded behind the m3eter, demand side and distribution cost items from the total cost estimate presented by ISO-NE, since we do not consider these costs in our study.

Cost group	All-Options	
Demand-side costs	$	-
Electricity storage	$	0.31
Electricity distribution	$	-
Electricity transmission	$	4.22
Gas pipelines	$	1.89
Gas power plants	$	0.21
In-state fuels production	$	0.67
Biomass power plants	$	0.09
Ground-mounted solar	$	1.46
Rooftop solar	$	-
Offshore wind	$	3.04
Hydro purchases	$	0.91
Zero carbon liquid imports	$	1.53
Zero carbon gas imports	$	0.14
Natural gas	$	0.23
Oil products	$	1.34
Other	$	1.05
Total (mean annualized costs 2024-bUSD for 2025-2050)	**$**	**17.08**
NPV 2024-bUSD (2% discount rate)	**$**	**343.57**

Table S14: Net present value of air emission costs (in millions of 2024 USD, discounted at 1.5%) across eight decarbonization pathways. Each cell reports the mean cost estimate along with its corresponding uncertainty bounds (in parentheses, 90% CI and NREL cost scenarios), facilitating a comparative assessment of financial implications by pathway and location in the region.

	A	**B1**	**B2**	**B3**	**C1**	**C2**	**C3**	**D**
Barnstable, MA	22.31 (21.82-23.18)	4.67 (4.44-5.17)	4.82 (4.57-5.31)	4.71 (4.48-5.06)	5.32 (5.12-5.67)	4.9 (4.68-5.41)	4.71 (4.48-5.06)	19.97 (19.35-21.06)
Berkshire, MA	2.95 (1.58-3.13)	0.38 (0.27-0.49)	0.6 (0.44-0.76)	0.38 (0.28-0.5)	0.58 (0.43-0.72)	0.52 (0.37-0.67)	0.31 (0.22-0.41)	1.42 (1.15-1.68)
Bristol, MA	25.05 (5.91-25.96)	18.44 (6.23-19.1)	20.3 (19.55-20.98)	18.24 (17.47-19.07)	13.5 (1.17-14.13)	19.02 (18.3-19.65)	17.09 (16.29-17.8)	24.08 (3.67-26.07)
Chittenden, VT	16.87 (16.13-17.67)	3.76 (3.58-4.27)	3.8 (3.6-4.33)	3.76 (3.58-4.35)	3.86 (3.69-4.25)	3.81 (3.65-4.37)	3.76 (3.58-4.35)	17.11 (16.42-17.88)
Coos, NH	23.43 (22.71-24.26)	30.16 (29.29-30.84)	31.38 (30.6-32.29)	29.66 (28.85-30.37)	19.37 (18.17-20.16)	30.26 (29.42-30.87)	28.72 (27.72-29.62)	23.46 (22.74-24.29)
Cumberland, ME	94.13 (29.89-96.68)	37.76 (18.04-39.58)	40.56 (18.12-42.32)	37.68 (36.06-39.37)	34.74 (20.18-36.64)	39.16 (37.79-40.87)	36.45 (17.8-38.07)	96.77 (72.41-103.08)
Essex, MA	24.28 (1.16-28.26)	21.38 (0.07-22.55)	23.96 (0.08-25.23)	21.12 (19.98-22.14)	15.91 (0.09-17.23)	22.33 (0.08-23.52)	19.67 (0.07-20.67)	28.93 (0.8-31.88)
Fairfield, CT	100.72 (0.04-105.52)	57.47 (0.11-60.03)	67.37 (1.25-69.83)	57.1 (53.34-59.54)	49.93 (48.63-50.95)	61.85 (50.9-64.12)	52.28 (20.91-54.69)	176.41 (80.9-178.3)
Hampden, MA	16.97 (12.58-18.5)	12.89 (12.04-13.5)	14.46 (9.81-15.11)	12.72 (11.89-13.39)	9.65 (9.14-10.15)	13.34 (12.59-13.94)	11.83 (11.09-12.51)	16.88 (14.44-19.17)
Hillsborough, NH	43.36 (40.81-45.51)	7.35 (5.39-9.27)	12.16 (9.26-14.69)	7.27 (5.42-9.25)	9.67 (7.7-11.81)	10.05 (7.63-12.4)	6.11 (4.46-7.87)	23.29 (2.66-27.28)
Litchfield, CT	0.26 (0.25-0.26)	0.05 (0.04-0.05)	0.05 (0.05-0.05)	0.05 (0.05-0.05)	0.06 (0.06-0.07)	0.05 (0.05-0.05)	0.05 (0.05-0.05)	0.2 (0.11-0.21)
Merrimack, NH	70.62 (61.88-71.75)	18.09 (17.89-18.41)	18.28 (18.05-18.73)	18.15 (17.93-18.53)	18.75 (16.42-19.24)	18.37 (18.15-18.81)	18.15 (17.93-18.53)	69.51 (68.74-70.68)
Middlesex, CT	41.77 (0.01-44.73)	15.84 (13.68-17.64)	20.67 (18.39-22.36)	15.69 (13.67-17.46)	15.27 (14.33-16.03)	18.41 (16.28-19.87)	14.07 (12.17-15.74)	40.83 (38.7-42.46)
Middlesex, MA	39.75 (38.71-40.74)	10.45 (10.08-11.11)	10.36 (10.02-10.96)	10.36 (10.04-10.83)	10.22 (9.95-10.49)	10.28 (9.99-10.59)	10.36 (10.04-10.83)	39.44 (38.38-40.41)

	A	B1	B2	B3	C1	C2	C3	D
New Haven, CT	188.75 (36.73-195.24)	147.91 (143.55-151.06)	158.86 (154.82-161.83)	146.45 (142.53-149.18)	123.34 (122.31-124.62)	150.62 (75.49-153.11)	140.37 (40.52-143.22)	250.92 (60.09-254.62)
New London, CT	24.08 (23.53-25.03)	1.09 (0.98-1.18)	1.16 (1.06-1.25)	1.11 (1.01-1.2)	1.33 (1.23-1.46)	1.19 (1.09-1.29)	1.11 (1.01-1.2)	17.74 (16.83-18.79)
Newport, RI	14.17 (13.68-14.74)	13.75 (13.35-14.15)	14.75 (14.39-15.1)	13.54 (13.14-13.9)	9.38 (9.17-9.63)	13.86 (13.55-14.28)	12.89 (12.5-13.28)	22.44 (21.95-24.29)
Norfolk, MA	139.72 (30.38-146.15)	73.54 (29.6-78.51)	87.34 (28.42-92.66)	73.06 (66.86-78.09)	72.05 (28.81-74.73)	80.7 (74.71-85.37)	68.44 (29.97-73.01)	124.91 (30.41-130.22)
Oxford, ME	2.77 (2.65-3.18)	2.62 (2.48-2.76)	2.92 (2.79-3.08)	2.59 (2.45-2.72)	1.92 (1.82-2.04)	2.72 (2.59-2.86)	2.42 (2.28-2.52)	3.36 (3.07-3.67)
Penobscot, ME	1.69 (1.58-1.8)	0.22 (0.16-0.27)	0.36 (0.16-0.45)	0.21 (0.16-0.27)	0.3 (0.23-0.37)	0.3 (0.22-0.37)	0.18 (0.13-0.23)	0.74 (0.61-0.88)
Providence, RI	155.66 (54.62-161.63)	85.08 (51.56-90.5)	100.14 (58.36-106.62)	84.71 (78.94-89.84)	82.23 (78.76-85.37)	92.86 (86.42-98.6)	79.45 (48.35-84.13)	241.53 (92.83-248.91)
Rockingham, NH	215.91 (118.4-221.38)	47.93 (19.91-50.4)	53.96 (20.84-56.58)	48.08 (45.5-50.54)	51.99 (50.55-53.39)	52.21 (40.66-54.41)	46.22 (20.1-48.73)	240.21 (66.34-244.53)
Suffolk, MA	9.71 (9.28-10.18)	3.9 (3.85-3.94)	3.85 (3.78-3.91)	3.89 (3.84-3.94)	3.59 (3.44-3.71)	3.83 (3.74-3.89)	3.89 (3.84-3.94)	13.2 (12.87-13.52)
Windham, CT	57.98 (54.7-60.91)	23.34 (18.67-26.79)	31.95 (26.68-35.24)	23.13 (18.61-26.45)	23.6 (21.41-25.14)	28.04 (23.34-31.1)	20.5 (16.41-23.62)	81.04 (51.57-84.08)
Worcester, MA	109.49 (47.81-114.19)	38.35 (30.78-43.62)	53.09 (1.14-59.23)	38.01 (30.87-43.23)	40.14 (35.61-43.69)	46.47 (38.87-51.85)	33.5 (0.74-38.51)	88.71 (43.48-95.3)

Table S15: Net present value of air emission costs (in millions of 2024 USD, discounted at 2%) across eight decarbonization pathways

	A	B1	B2	B3	C1	C2	C3	D
Barnstable, MA	20.92 (20.46-21.73)	4.6 (4.37-5.08)	4.74 (4.5-5.23)	4.63 (4.41-4.98)	5.23 (5.03-5.57)	4.81 (4.6-5.32)	4.63 (4.41-4.98)	18.75 (18.17-19.78)
Berkshire, MA	2.73 (1.48-2.91)	0.36 (0.26-0.46)	0.57 (0.41-0.73)	0.36 (0.26-0.47)	0.56 (0.41-0.7)	0.5 (0.36-0.64)	0.3 (0.21-0.4)	1.32 (1.06-1.56)
Bristol, MA	23.52 (5.52-24.37)	17.6 (5.97-18.21)	19.31 (18.62-19.95)	17.42 (16.7-18.21)	13.09 (1.15-13.7)	18.16 (17.49-18.75)	16.36 (15.6-17.03)	22.65 (3.46-24.52)
Chittenden, VT	15.86 (15.16-16.62)	3.7 (3.53-4.21)	3.74 (3.54-4.27)	3.7 (3.53-4.29)	3.8 (3.64-4.19)	3.75 (3.6-4.3)	3.7 (3.53-4.29)	16.09 (15.44-16.82)
Coos, NH	22.03 (21.35-22.81)	28.55 (27.76-29.17)	29.65 (28.93-30.48)	28.11 (27.36-28.75)	18.7 (17.54-19.44)	28.65 (27.88-29.2)	27.23 (26.32-28.06)	22.07 (21.38-22.84)
Cumberland, ME	88.43 (29.19-90.81)	36.53 (17.74-38.29)	39.16 (17.82-40.85)	36.48 (34.91-38.11)	33.85 (19.84-35.7)	37.9 (36.6-39.58)	35.33 (17.5-36.9)	90.98 (68.07-96.91)
Essex, MA	22.81 (1.09-26.55)	20.39 (0.07-21.5)	22.79 (0.08-23.99)	20.17 (19.1-21.14)	15.42 (0.09-16.7)	21.32 (0.08-22.44)	18.82 (0.07-19.77)	27.2 (0.75-29.98)
Fairfield, CT	94.6 (0.03-99.1)	54.94 (0.11-57.36)	64.18 (1.2-66.48)	54.66 (51.09-56.97)	48.47 (47.23-49.44)	59.21 (48.64-61.34)	50.17 (20.06-52.45)	163.24 (76.09-165.01)
Hampden, MA	15.9 (11.83-17.34)	12.29 (11.49-12.86)	13.74 (9.49-14.34)	12.14 (11.36-12.77)	9.36 (8.86-9.83)	12.73 (12.03-13.29)	11.32 (10.62-11.94)	15.86 (13.58-18.01)
Hillsborough, NH	40.3 (37.84-42.38)	6.96 (5.09-8.8)	11.5 (8.75-13.92)	6.9 (5.13-8.8)	9.4 (7.48-11.49)	9.58 (7.26-11.85)	5.81 (4.23-7.51)	21.65 (2.59-25.42)
Litchfield, CT	0.24 (0.24-0.24)	0.05 (0.04-0.05)	0.05 (0.05-0.05)	0.05 (0.04-0.05)	0.06 (0.06-0.06)	0.05 (0.05-0.05)	0.05 (0.04-0.05)	0.19 (0.1-0.2)
Merrimack, NH	66.39 (58.62-67.46)	17.79 (17.59-18.1)	17.98 (17.75-18.42)	17.84 (17.64-18.22)	18.44 (16.17-18.91)	18.06 (17.85-18.49)	17.84 (17.64-18.22)	65.37 (64.65-66.47)
Middlesex, CT	39.14 (0.01-41.92)	15.18 (13.12-16.9)	19.72 (17.56-21.33)	15.06 (13.13-16.75)	14.88 (13.97-15.61)	17.69 (15.66-19.09)	13.54 (11.73-15.15)	38.33 (36.3-39.87)
Middlesex, MA	37.38 (36.39-38.3)	10.28 (9.91-10.93)	10.19 (9.85-10.78)	10.19 (9.88-10.65)	10.05 (9.78-10.32)	10.11 (9.82-10.41)	10.19 (9.88-10.65)	37.09 (36.1-38.01)
New Haven, CT	177.27 (34.84-183.33)	140.71 (136.63-143.64)	150.84 (147.09-153.6)	139.45 (135.77-142.01)	118.61 (117.62-119.85)	143.44 (71.54-145.75)	133.79 (38.59-136.48)	234.34 (56.35-237.83)
New London, CT	22.49 (21.96-23.37)	1.09 (0.98-1.17)	1.15 (1.05-1.24)	1.1 (1-1.19)	1.33 (1.22-1.45)	1.19 (1.08-1.28)	1.1 (1-1.19)	16.61 (15.75-17.58)

	A	B1	B2	B3	C1	C2	C3	D
Newport, RI	13.32 (12.87-13.86)	13.05 (12.68-13.42)	13.97 (13.64-14.29)	12.87 (12.49-13.2)	9.07 (8.87-9.3)	13.16 (12.88-13.55)	12.26 (11.9-12.62)	21.05 (20.59-22.79)
Norfolk, MA	130.66 (28.31-136.65)	70 (28.08-74.76)	82.97 (26.97-88.03)	69.62 (63.69-74.44)	69.42 (27.38-72.06)	77.03 (71.29-81.49)	65.31 (28.43-69.7)	117.09 (28.53-122.14)
Oxford, ME	2.61 (2.49-2.99)	2.5 (2.37-2.63)	2.77 (2.65-2.92)	2.47 (2.34-2.59)	1.86 (1.76-1.98)	2.59 (2.48-2.73)	2.31 (2.18-2.41)	3.16 (2.89-3.45)
Penobscot, ME	1.56 (1.46-1.67)	0.2 (0.15-0.26)	0.34 (0.16-0.43)	0.2 (0.15-0.26)	0.29 (0.23-0.36)	0.28 (0.21-0.35)	0.17 (0.12-0.21)	0.69 (0.57-0.82)
Providence, RI	145.74 (51.3-151.33)	80.91 (48.93-86.1)	95.11 (55.36-101.28)	80.64 (75.1-85.57)	79.12 (75.71-82.19)	88.55 (82.37-94.05)	75.72 (45.92-80.23)	223.01 (87.16-229.99)
Rockingham, NH	202.71 (111.23-207.79)	46.75 (19.64-49.12)	52.46 (20.54-54.96)	46.92 (44.45-49.3)	51.02 (49.61-52.38)	50.93 (39.59-53.04)	45.18 (19.82-47.6)	223.91 (61.35-227.98)
Suffolk, MA	9.12 (8.72-9.56)	3.83 (3.78-3.87)	3.79 (3.72-3.84)	3.83 (3.78-3.87)	3.52 (3.38-3.65)	3.77 (3.68-3.83)	3.83 (3.78-3.87)	12.41 (12.1-12.71)
Windham, CT	54.32 (51.29-57.08)	22.3 (17.84-25.6)	30.42 (25.4-33.53)	22.14 (17.81-25.33)	22.97 (20.84-24.46)	26.89 (22.4-29.82)	19.68 (15.75-22.68)	75.21 (48.24-78.11)
Worcester, MA	102.34 (44.76-106.73)	36.61 (29.38-41.65)	50.51 (1.09-56.35)	36.36 (29.53-41.36)	39.05 (34.65-42.51)	44.53 (37.27-49.68)	32.14 (0.72-36.95)	83.07 (40.82-89.32)

Table S16: Net present value of air emission costs (in millions of 2024 USD, discounted at 2.5%) across eight decarbonization pathways

	A	B1	B2	B3	C1	C2	C3	D
Barnstable, MA	19.64 (19.21-20.4)	4.52 (4.3-5)	4.66 (4.42-5.14)	4.55 (4.34-4.9)	5.14 (4.95-5.47)	4.73 (4.53-5.23)	4.55 (4.34-4.9)	17.64 (17.09-18.61)
Berkshire, MA	2.53 (1.38-2.71)	0.34 (0.24-0.44)	0.54 (0.39-0.69)	0.34 (0.25-0.45)	0.54 (0.4-0.68)	0.48 (0.34-0.61)	0.28 (0.2-0.38)	1.22 (0.98-1.46)
Bristol, MA	22.12 (5.17-22.92)	16.81 (5.74-17.38)	18.4 (17.75-18.99)	16.66 (15.99-17.41)	12.7 (1.13-13.3)	17.36 (16.74-17.92)	15.67 (14.96-16.31)	21.34 (3.25-23.1)
Chittenden, VT	14.94 (14.28-15.65)	3.65 (3.48-4.15)	3.69 (3.49-4.21)	3.65 (3.48-4.22)	3.75 (3.58-4.13)	3.7 (3.55-4.24)	3.65 (3.48-4.22)	15.15 (14.55-15.84)
Coos, NH	20.75 (20.11-21.48)	27.06 (26.34-27.64)	28.06 (27.38-28.82)	26.67 (25.99-27.26)	18.07 (16.94-18.77)	27.16 (26.47-27.67)	25.87 (25.03-26.62)	20.79 (20.14-21.52)
Cumberland, ME	83.21 (28.51-85.44)	35.38 (17.45-37.08)	37.84 (17.53-39.47)	35.35 (33.84-36.92)	33 (19.51-34.81)	36.73 (35.49-38.36)	34.28 (17.21-35.8)	85.67 (64.1-91.25)
Essex, MA	21.47 (1.02-24.98)	19.48 (0.07-20.52)	21.7 (0.07-22.83)	19.29 (18.29-20.21)	14.95 (0.09-16.18)	20.38 (0.08-21.45)	18.03 (0.07-18.93)	25.62 (0.71-28.23)
Fairfield, CT	89 (0.03-93.23)	52.59 (0.1-54.87)	61.23 (1.15-63.38)	52.39 (49-54.58)	47.08 (45.89-48)	56.76 (46.53-58.75)	48.19 (19.27-50.36)	151.3 (71.67-152.97)
Hampden, MA	14.92 (11.14-16.28)	11.73 (10.98-12.26)	13.07 (9.19-13.63)	11.6 (10.87-12.19)	9.08 (8.6-9.54)	12.17 (11.51-12.68)	10.84 (10.18-11.42)	14.92 (12.79-16.95)
Hillsborough, NH	37.51 (35.14-39.53)	6.6 (4.81-8.37)	10.89 (8.27-13.22)	6.56 (4.86-8.39)	9.14 (7.27-11.18)	9.15 (6.93-11.34)	5.54 (4.02-7.18)	20.16 (2.53-23.72)
Litchfield, CT	0.23 (0.22-0.23)	0.05 (0.04-0.05)	0.05 (0.05-0.05)	0.05 (0.04-0.05)	0.06 (0.06-0.06)	0.05 (0.05-0.05)	0.05 (0.04-0.05)	0.18 (0.1-0.19)
Merrimack, NH	62.52 (55.61-63.53)	17.5 (17.3-17.8)	17.68 (17.46-18.12)	17.55 (17.34-17.92)	18.13 (15.93-18.6)	17.76 (17.55-18.19)	17.55 (17.34-17.92)	61.57 (60.9-62.61)
Middlesex, CT	36.74 (0.01-39.35)	14.56 (12.6-16.2)	18.84 (16.78-20.37)	14.48 (12.63-16.1)	14.51 (13.62-15.22)	17.01 (15.07-18.35)	13.06 (11.32-14.59)	36.03 (34.1-37.5)
Middlesex, MA	35.2 (34.27-36.07)	10.11 (9.75-10.75)	10.02 (9.69-10.6)	10.02 (9.71-10.48)	9.88 (9.62-10.15)	9.94 (9.66-10.24)	10.02 (9.71-10.48)	34.94 (34.01-35.81)
New Haven, CT	166.75 (33.11-172.42)	134.05 (130.22-136.78)	143.43 (139.95-146.01)	132.97 (129.51-135.37)	114.18 (113.22-115.37)	136.78 (67.89-138.93)	127.7 (36.8-130.23)	219.21 (52.92-222.5)
New London, CT	21.03 (20.53-21.86)	1.08 (0.97-1.16)	1.14 (1.05-1.23)	1.1 (0.99-1.18)	1.32 (1.22-1.44)	1.18 (1.07-1.27)	1.1 (0.99-1.18)	15.57 (14.76-16.48)

	A	B1	B2	B3	C1	C2	C3	D
Newport, RI	12.54 (12.12-13.05)	12.41 (12.07-12.74)	13.24 (12.94-13.53)	12.24 (11.9-12.54)	8.77 (8.58-8.99)	12.51 (12.25-12.86)	11.68 (11.35-12.01)	19.77 (19.33-21.4)
Norfolk, MA	122.37 (26.43-127.97)	66.72 (26.68-71.27)	78.92 (25.61-83.74)	66.43 (60.74-71.05)	66.96 (26.05-69.54)	73.6 (68.11-77.88)	62.4 (27.01-66.63)	109.93 (26.81-114.75)
Oxford, ME	2.45 (2.34-2.81)	2.38 (2.26-2.51)	2.64 (2.52-2.78)	2.36 (2.24-2.47)	1.8 (1.71-1.92)	2.48 (2.37-2.6)	2.21 (2.09-2.31)	2.98 (2.72-3.25)
Penobscot, ME	1.45 (1.35-1.55)	0.19 (0.14-0.24)	0.33 (0.15-0.4)	0.19 (0.14-0.24)	0.29 (0.22-0.35)	0.27 (0.2-0.34)	0.16 (0.11-0.2)	0.64 (0.53-0.76)
Providence, RI	136.68 (48.27-141.92)	77.04 (46.5-82.03)	90.45 (52.59-96.34)	76.86 (71.53-81.61)	76.21 (72.85-79.22)	84.55 (78.6-89.83)	72.25 (43.68-76.61)	206.27 (81.94-212.89)
Rockingham, NH	190.63 (104.66-195.36)	45.62 (19.37-47.91)	51.05 (20.26-53.43)	45.82 (43.45-48.12)	50.08 (48.71-51.41)	49.71 (38.57-51.75)	44.19 (19.55-46.53)	209.09 (56.87-212.93)
Suffolk, MA	8.59 (8.21-9)	3.77 (3.72-3.81)	3.72 (3.66-3.78)	3.76 (3.71-3.81)	3.47 (3.32-3.58)	3.7 (3.62-3.77)	3.76 (3.71-3.81)	11.69 (11.39-11.97)
Windham, CT	50.97 (48.17-53.58)	21.33 (17.06-24.5)	29 (24.21-31.95)	21.22 (17.07-24.28)	22.36 (20.29-23.8)	25.81 (21.51-28.62)	18.91 (15.14-21.8)	69.9 (45.19-72.66)
Worcester, MA	95.8 (41.98-99.93)	35 (28.09-39.83)	48.12 (1.05-53.68)	34.82 (28.27-39.61)	38.02 (33.73-41.37)	42.72 (35.77-47.65)	30.86 (0.69-35.5)	77.91 (38.38-83.86)

Table S17: Environmental impact metrics of energy technologies across scenarios B1–B3, C1–C3 and D. Values reported are the means, with 90% CI shown in brackets.

		Pathway						
Technology	**Unit**	**B1**	**B2**	**B3**	**C1**	**C2**	**C3**	**D**
Bird mortality								
On-shore wind	million bird deaths	0.01 (0.00-0.02)	0.01 (0.00-0.02)	0.01 (0.00-0.02)	0.00 (0.00-0.00)	0.01 (0.00-0.02)	0.01 (0.00-0.02)	0.00 (0.00-0.01)
	million bat deaths	0.08 (0.02-0.16)	0.08 (0.02-0.16)	0.08 (0.02-0.16)	0.00 (0.00-0.00)	0.08 (0.02-0.16)	0.08 (0.02-0.16)	0.03 (0.01-0.07)
Solar	million bird deaths	0.21 (0.01-0.43)	0.21 (0.01-0.43)	0.21 (0.01-0.43)	0.00 (0.00-0.00)	0.21 (0.01-0.43)	0.21 (0.01-0.43)	0.05 (0.00-0.10)
Sum	million avian deaths	0.29 (0.05-0.78)	0.29 (0.05-0.78)	0.29 (0.05-0.78)	0.00 (0.00-0.00)	0.29 (0.05-0.78)	0.29 (0.05-0.78)	0.08 (0.02-0.20)
Land use								
Hydropower reservoirs	million hectares	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.35 (0.20-0.50)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)
Natural gas	million hectares	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)
On-shore wind	million hectares	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)
Small modular nuclear	million hectares	0.41 (0.17-0.69)	0.42 (0.17-0.73)	0.41 (0.18-0.70)	0.00 (0.00-0.00)	0.41 (0.18-0.71)	0.41 (0.17-0.69)	0.18 (0.08-0.29)
Solar	million hectares	0.23 (0.10-0.37)	0.23 (0.11-0.38)	0.22 (0.10-0.36)	0.00 (0.00-0.00)	0.22 (0.11-0.36)	0.23 (0.10-0.38)	0.05 (0.02-0.08)
Sum	million hectares	0.63 (0.31-1.03)	0.65 (0.31-1.10)	0.99 (0.59-1.47)	0.00 (0.00-0.00)	0.64 (0.31-1.10)	0.63 (0.30-1.07)	0.23 (0.10-0.40)
View shed								
High-voltage transmission to/from Hydro-Québec	million people within viewshed	0.20 (0.07-0.39)	0.00 (0.00-0.00)	0.19 (0.10-0.33)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.23 (0.11-0.38)	0.27 (0.07-0.80)
High-voltage transmission to/from NYISO	million people within viewshed	0.90 (0.18-2.38)	0.29 (0.08-0.61)	0.79 (0.08-2.61)	0.00 (0.00-0.00)	0.76 (0.21-2.63)	0.68 (0.08-1.33)	0.64 (0.05-2.17)
Off-shore wind	million people within viewshed	6.52 (3.47-8.58)	6.16 (3.58-9.82)	3.84 (1.96-6.26)	0.00 (0.00-0.00)	6.48 (3.52-10.61)	3.60 (1.71-5.91)	0.63 (0.00-2.06)

		Pathway						
Technology	**Unit**	**B1**	**B2**	**B3**	**C1**	**C2**	**C3**	**D**
Solar	million people within viewshed	3.88 (3.46-4.49)	4.31 (3.35-4.99)	4.20 (3.34-5.52)	0.00 (0.00-0.00)	4.01 (3.43-4.35)	4.32 (3.43-5.49)	0.80 (0.58-1.11)
Sum	million people within viewshed	11.51 (7.19-15.85)	10.77 (7.01-15.42)	9.01 (5.49-14.71)	0.00 (0.00-0.00)	11.24 (7.17-17.59)	8.83 (5.33-13.11)	2.34 (0.71-6.14)
Water withdrawals for thermal generation								
Natural gas – dry-cooled	trillion gallons	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	2.57 (2.57-2.57)	0.33 (0.33-0.33)	0.21 (0.21-0.21)	0.00 (0.00-0.00)
Small modular nuclear – water-cooled	trillion gallons	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.05 (0.05-0.05)
Sum	trillion gallons	0.00 (0.00-0.00)	0.00 (0.00-0.00)	0.00 (0.00-0.00)	2.57 (2.57-2.57)	0.33 (0.33-0.33)	0.21 (0.21-0.21)	0.05 (0.05-0.05)

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