

Supplemental Information

Correlated uncertainty propagation enables multi-impact decision support for electrical system decarbonization

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1. Decarbonization pathways and scheduling of new generation and retirements

Table S1 reports the 2050 endpoint assumptions for each modeled pathway, including new generation, storage, intertie capacity, Canadian hydropower development, and forced fossil-fuel retirements. These endpoint values correspond to the pathway definitions described in the main text and are translated into annual build-out and retirement schedules in Table S2. PHASED (Probabilistic Hourly Assessment of Scenarios for Electrical Decarbonization) gets this annual schedule as an input variable. The pathways represent plausible New England decarbonization pathways rather than a forecast of the most likely resource mix.

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 Québec	None	+4.1 GW	None	+6 GW	None	None	+4.1 GW	+4.1 GW
New hydropower reservoirs in Québec	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

Table S2 provides the annual implementation schedule used to interpolate from the current system to the 2050 endpoint assumptions in Table S1. Pathways A and D retain existing large nuclear and natural-gas capacity through 2050 and assume no forced fossil-fuel retirements, consistent with the U.S. EIA No-IRA scenario summarized in Table S3 (Gerrard, 2024; Osaka, 2024; U.S. EIA AEO, 2023). For all other pathways, scheduled fossil-fuel retirements include full coal retirement by 2030 and a set retirement schedule for low-utilization units whose primary fuel is oil, following ISO-NE modeling assumptions (Commonwealth of Massachusetts, 2020). Oil-fired units selected for retirement were identified by filtering facilities using oil as their primary fuel, calculating real average capacity factors, and assigning 2030 retirement to units at or below the 75th percentile, so that less-utilized units were retired first.

Additional age-based retirements use economic lifetimes of 75 years for coal-fired plants, 45 years for wood-fired plants, and 55 years for other fossil-fuel plants, based on NREL

assumptions and facility data from eGRID and EIA Form 860 (U.S. EIA 860, 2023; U.S. EPA eGrid, 2022). Facility- and unit-level retirement assumptions are reported in Table S4.

2. Model formulation

2.1. Notation

2.1.1. Sets and indices

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

$g \in \mathcal{G} = \{\text{solar, onshore wind, offshore wind, nuclear, hydro, biomass, SMR, fossil}\}$: generation technologies

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

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

$s \in \mathcal{S}$: Monte Carlo simulation; ω : a sampled realization.

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

$p \in \mathcal{P}$: prescribed electricity 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 for technology g in hour t ; fixed or sampled as listed in Table S5.

$\text{Cap}_{j,t}^{\text{LT}}, \text{Cap}_{j,t}^{\text{spot}}$: 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 change in output per hour (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)

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

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

r, y_0 : discount rate, base year

2.1.3. State and calculated 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)

$\text{SOC}_t \in [0, E_{\text{max},t}]$: 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 is represented using the ISO-NE 2025-2050 “High Electrification” pathway (also known as “All Options” pathway) obtained from the Commonwealth of Massachusetts through a Public Records Act request. This pathway assumes medium flexibility in end-use loads, including incentivized consumer behavior to reduce consumption during peak demand. In 2050, the pathway reaches peak hourly demand of 53,715 MW on January 24 and total annual demand of 203 TWh. Simulations reported here use the full hourly demand profile for January 1, 2025 through December 31, 2050, totaling 227,904 hourly timesteps, rather than representative demand slices or reduced-form time periods. Raw demand data for all available demand pathways are archived with the reproducibility materials to support reanalysis under alternative forecasts. Demand is fixed across simulations; this study does not sample uncertainty in the demand forecast.

2.3. Hourly dispatch formulation

PHASED is a sequential dispatch model written directly in R that dispatches electricity generation (including imports and battery storage) in a merit order to meet demand. It is implemented independently of PyPSA, GenX, Switch and openTEPES and does not solve a cost-minimization problem. The merit order allocation rule favors units with higher sampled hourly capacity factors. Binary unit commitment, minimum up and down times, start-up costs, power flow, and intra-regional transmission constraints are absent from the mechanistic formulation but are captured implicitly in the historical generation data from which we sample.

Dispatch at each hourly timestep t follows an energy balance in which generation, imports, battery discharge and unmet demand equal demand, battery charging and curtailment. Equation 1 states this balance; each term is defined in the sections that follow (low-carbon generation in Section 2.4, battery storage in Section 2.5, imports in Section 2.6, existing fossil fleet dispatch in Section 2.7, and curtailment and unmet demand in Section 2.8).

$$\sum_{g \neq \text{Fossil}} G_{g,t} + I_t + d_t + \sum_u G_{u,t} + N_t + \text{Short}_t = D_t + c_t + \text{Curt}_t \quad \text{Eq. 1}$$

Here, t denotes the hourly timestep, g denotes a non-fossil generation technology, and u denotes a generating unit in the existing fossil fuel fleet. $G_{g,t}$ is generation from technology g , $G_{u,t}$ is output from unit u , and N_t is output from newly built natural-gas capacity. The two summations give total non-fossil generation and total existing-fleet generation, respectively.

I_t is total electricity imported after dispatch adjustments; d_t is battery discharge delivered to the grid; D_t is electricity demand; and c_t is electricity drawn from the grid to charge the battery. Short_t is unmet demand, and Curt_t is the curtailment (i.e., aggregate surplus) removed from the balance. All terms are in MWh over the t timestep. Battery losses are accounted for in the storage equations in Section 2.5.

For non-biomass clean resources k , Section 2.4 gives available generation as installed capacity multiplied by capacity factor and the dispatch interval. Nuclear, domestic hydro, and SMR use fixed technology capacity factors; solar and wind use the selected technology profiles. Define L_t as their sum. Scheduled imports I_t^0 equal 0.95 times new Québec contracted capacity plus each other intertie's sampled capacity factor, capped between 0 and 0.95, times capacity. Biomass availability and dispatched output follow Section 2.4.2.

Storage input is represented as E_t , with $P_t = E_t/(8 \text{ h})$ and an optional inverter cap. Fossil fuel generation is excluded when calculating the surplus available for battery charging. Where $X_t = L_t + B_t + I_t^0 - D_t$. If $X_t > 0$, the battery charges by $c_t = \min(X_t, P_t \Delta t, (E_t - \rho S_{t-1})/\eta)$. If $X_t < 0$, it discharges by $d_t = \min(-X_t, P_t \Delta t, \eta \rho S_{t-1})$. The other flow is zero. The state begins at zero, remains between zero and E_t , and carries between days, per the storage state-update equation in Section 2.5.2.

After battery operation, new-gas output N_t is calculated from installed new-gas capacity and its fixed facility capacity factor. The existing-fleet requirement follows the system-level fossil requirement equation in Section 2.7.1.

$\bar{F}_t$ is the hourly upper limit on existing fossil-fuel generation, based on historical output and adjusted for scheduled retirements. Each represented unit draws a generation value $g_{u,t}^0$ from stored values for that day of the year and hour. If the sum exceeds R_t , the excess is removed sequentially from units sorted by ascending $g_{u,t}^0/K_u$. If the sum is lower, this allocation step does not fill the gap. The rule therefore retains higher sampled capacity factors first. Denote output after this allocation by $g_{u,t}^a$. Missing hourly generation values within each unit's modeled period are initially set to zero. A backward pass raises preceding output to limit upward changes, followed by a forward pass that raises current output to limit downward changes. The two ramp adjustments are applied as described in Section 2.7.2.

The final unit output is $\text{round}(\max(g_{u,t}^f, g_{\min_u} \Delta t), 2)$. The minimum floor is applied after both passes. The code does not then solve a commitment problem, reallocate the restored unit output

or reapply an individual maximum-output constraint. The backward pass uses future sampled output within the processed time block; this is *computational foresight*, not a simulation of day-ahead market clearing. We derive minimum and maximum generation levels using U.S. EPA CAMPD historical dataset for each existing fossil fuel generating unit. The non-retired fossil fuel facility input contains 18 units with a positive minimum generation level, totaling 38 MW. This is 0.070–0.461% of hourly demand over 2025–2050, or 0.191% of mean hourly demand. The combined minimum generation level falls to 14 MW by 2050 under the retirement schedule.

After summing adjusted existing-unit generation F_t , the model recalculates storage operation, allowing batteries to charge only from surplus low-carbon generation and imports. If needed, it then increases imports to cover remaining shortages in the order contracted Québec, other Québec, NYISO, and NBSO. Each increment is capped by unused inertia headroom, $0.95K_{j,t}\Delta t - I_{j,t}^0$. Contracted Québec is already at its maximum capacity factor, so normally has no headroom. Final imports are I_t , unmet demand is U_t , and aggregate curtailment is Q_t , consistent with the energy balance of Eq. 1.

Any remaining generation deficit is recorded as unmet demand, and any remaining excess as curtailment. Curtailment can include restored fossil fuel generation as well as renewable generation. The model excludes transmission constraints within the region and uses prescribed inertia capacities.

2.4. 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 selected from the supplied percentile profiles. Solar and wind capacity factors are selected from the corresponding technology-specific ISO-NE profiles, as described in Section 2.4.1. Available hourly generation equals installed capacity multiplied by capacity factor and the one-hour interval. Solar, wind, nuclear, domestic hydropower and SMRs are dispatched first. Biomass then supplies remaining demand after these resources and scheduled imports (Section 2.4.2).

$$G_t^{\text{lowcarbon}} \equiv \sum_{g \in \mathcal{G}\{\text{lowcarbon}\}} G_{g,t} \quad \text{Eq. 2}$$

$$G_{\text{Solar},t} = \text{Cap}_{\text{Solar},t} \text{CF}_{\text{Solar},t}(\omega) \times \Delta t \quad \text{Eq. 3}$$

$$G_{\text{Wind}_{\text{on}},t} = \text{Cap}_{\text{Wind}_{\text{on}},t} \text{CF}_{\text{Wind}_{\text{on}},t}(\omega) \times \Delta t \quad \text{Eq. 4}$$

$$G_{\text{Wind}_{\text{off}},t} = \text{Cap}_{\text{Wind}_{\text{off}},t} \text{CF}_{\text{Wind}_{\text{off}},t}(\omega) \times \Delta t \quad \text{Eq. 5}$$

$$G_{\text{Nuclear},t} = \text{Cap}_{\text{Nuclear},t} \text{CF}_{\text{Nuclear}} \times \Delta t \quad \text{Eq. 6}$$

$$G_{\text{Hydro},t} = \text{Cap}_{\text{Hydro},t} \text{CF}_{\text{Hydro}} \times \Delta t \quad \text{Eq. 7}$$

$$G_{\text{Biomass},t} = \min(0.60 K_{b,t}, R_t^b) \times \Delta t \quad \text{Eq. 8}$$

$$G_{\text{SMR},t} = \text{Cap}_{\text{SMR},t} \text{CF}_{\text{SMR}} \times \Delta t \quad \text{Eq. 9}$$

Let L_t be available generation from solar, wind, nuclear, domestic hydropower and SMRs, and I_t^0 be scheduled imports. Residual demand for biomass is $R_t^b = \max(0, D_t - L_t - I_t^0)$. Biomass availability is $0.60K_{\beta,t}\Delta t$, with $\Delta t = 1$ h. Unused biomass availability is recorded separately.

In hours where demand can be satisfied with available low-carbon sources and/or required ramping of fossil fuels to meet future demand, excess low-carbon energy is used to charge batteries within technical constraints (SI Section 2.5). The model supports an option to charge batteries from fossil ramping surplus, but all results presented in this study restrict charging to surplus low-carbon generation and imports only. If battery charging cannot dissipate the surplus, output is curtailed.

2.4.1. 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 technology-specific profiles indexed by calendar day and hour 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).

Renewable dependence is inherited from the joint ISO-NE solar, onshore-wind and offshore-wind profiles. These percentile-indexed profiles represent the modeled relationships among annual average renewable capacity factors. PHASED interpolates the supplied profiles to indices 1–99 and retains those relationships in the selected renewable realizations. The corresponding solar and wind availability values are propagated through hourly dispatch, with the same sampled renewable realization applied across pathways.

2.4.2. 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). Nuclear and domestic hydropower are dispatched first with wind, solar and SMRs. Biomass follows these resources and scheduled imports, before storage and existing fossil fuel generators. This order reflects biomass's higher marginal cost than wind and solar. 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 available generation accounts for 2.10 TWh (1.03% of demand). Aggregate biomass capacity is 400 MW in every pathway and year. At the assumed 0.60 capacity factor, available

generation is 2.1024 TWh in a non-leap year and 2.10816 TWh in a leap year. Biomass is dispatched after other clean generation and scheduled imports, and before battery operation and the existing fossil fuel fleet. The separately represented wood-fired units remain in the existing fossil fuel unit stack and are reported separately from aggregate biomass.

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.

2.5. Commercial battery storage

Battery storage is represented using an explicit state-of-charge formulation. As described in the main text, storage is used to absorb surplus low-carbon generation and discharge during hours when low-carbon generation and imports are insufficient to meet demand.

We model commercial lithium-ion battery storage with symmetric charge and discharge efficiencies of $\sqrt{0.85}$ (approximately 92.2%), corresponding to an 85% round-trip efficiency (NREL, 2024). Charging and discharging cannot occur simultaneously. Charging and discharging are limited by storage energy capacity divided by eight hours. Where an inverter rating is supplied, the lower of these two power limits applies; otherwise the reference power cap is energy capacity divided by eight hours.

2.5.1. Power cap from inverter and duration

Storage dispatch is capped 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 $E_{\max,t} \equiv \text{Cap}_t^{\text{stor}}$ (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:

$$P_{\max,t} = \min\left\{\frac{E_{\max,t}}{H^{\text{dur}}}, \text{Inv}_t\right\}, P_{\max,t} \geq 0 \quad \text{Eq. 10}$$

2.5.2. State update with retention and symmetric round trip

Battery state of charge (SOC) evolves according to one-way efficiency, hourly retention and physical caps. Let η_{rt} denote round-trip efficiency and $\eta = \sqrt{\eta_{\text{rt}}}$ the symmetric one-way efficiency. Let ρ denote hourly retention. Equation 11 updates SOC from the preceding hour.

$$\text{SOC}_t = \min\left\{\max\left(\rho \text{SOC}_{t-1} + \eta c_t - \frac{1}{\eta} d_t, 0\right), E_{\max,t}\right\} \quad \text{Eq. 11}$$

Charging and discharging energies are capped by $0 \leq c_t \leq P_{\max,t} \Delta t$ and $0 \leq d_t \leq P_{\max,t} \Delta t$, where $\Delta t = 1$ h.

Curtailement only charging requirement (battery may only charge from otherwise excess low-carbon generation):

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

Storage carries between days without a daily reset or hourly self-discharge ($\rho = 1$). The simulation uses a continuous hourly UTC index. However, the user can disable the multi day carryover. If multi day carryover is disabled, PHASED sets $\text{SOC}_t \leftarrow 0$ at local midnight before applying retention.

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

$$\Delta_t^{\text{bat}} = \eta c_t - \frac{1}{\eta} d_t \quad \text{Eq. 12}$$

2.6. 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 and D consider increased imports from Québec; with (B3) or without (B1 and C3) expanded generation in Québec. Recently negotiated import agreements between Québec 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)). Scheduled imports are supplied before biomass and existing fossil generation. Their purchase costs are included in total costs. 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 Québec under all pathways are under a fixed-price contract.

For other imports, we use historical data for 2011–2023 to develop capacity-factor profiles. We calculate historical variable hourly capacity factors by dividing real imports by available transmission capacity and apply them to the capacity schedule for 2025–2050. Historical percentile indices are sampled separately for existing Québec, NYISO and NBSO imports. Initially, sampled CFs are capped between zero and 0.95; new contracted Québec capacity uses a fixed CF of 0.95. After adjusted fossil generation and storage are known, imports can increase within unused intertie headroom, without resampling the historical index or price. If generation, storage and capped imports remain insufficient, an unmet-demand penalty is applied (SI Section 2.14).

Import amounts depend on the pathway and on hourly demand after other generation and storage. In 2025, Québec, NYISO and NBSO capacities are 2,125, 3,200 and 1,050 MW. By 2050, Québec capacity is 6,225 MW in B1/C3/D, 8,125 MW in B3 and 2,125 MW in A/B2/C1/C2. NYISO reaches 4,800 MW except A/C1, where it remains 3,200 MW; NBSO remains 1,050 MW. The annual capacity schedule is retained in Table S2. Delivered hourly

imports cannot exceed 0.95 times each link's MW capacity over one hour. After generation and storage are adjusted, imports can increase up to 0.95 of each link's capacity.

Let $\bar{CF}^{imp} = 0.95$ denote the maximum import capacity factor. Eq. 13 defines long-term contractual imports $I_{j,t}^{LT}$ from jurisdiction j at time t as a fixed fraction of available long-term transmission capacity $\text{Cap}_{j,t}^{LT}$, reflecting constant schedules under fixed-price agreements. Eq. 14 caps spot-market imports $I_{j,t}^{spot}$ by available spot-market transmission capacity $\text{Cap}_{j,t}^{spot}$ and a stochastic capacity factor $CF_{j,t}^{spot}(\omega)$ drawn from historical data. Eq. 15 defines total imports I_t as the sum of long-term and spot-market imports across all jurisdictions. Finally, Eq. 16 imposes a system-wide upper cap on total imports $\bar{I}_t$, determined by aggregate transmission capacity and the maximum import capacity factor $\bar{CF}^{imp}$.

$$I_{j,t}^{LT} = \text{Cap}_{j,t}^{LT} \cdot \bar{CF}^{imp} \quad \text{Eq. 13}$$

$$0 \leq I_{j,t}^{spot} \leq \text{Cap}_{j,t}^{spot} CF_{j,t}^{spot}(\omega) \quad \text{Eq. 14}$$

$$I_t = \sum_j (I_{j,t}^{LT} + I_{j,t}^{spot}) \quad \text{Eq. 15}$$

$$I_t \leq \bar{I}_t = \bar{CF}^{imp} \sum_j (\text{Cap}_{j,t}^{LT} + \text{Cap}_{j,t}^{spot}) \quad \text{Eq. 16}$$

2.6.1. Imports netting logic (headroom allocation)

Eq. 17 defines net imports I_t^{net} prior to calibration. When a system shortfall $\text{Short}_t > 0$ 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. 18 and Eq. 19 define long-term and spot-market headroom $H_{j,t}^{LT}$ and $H_{j,t}^{spot}$ as the difference between maximum feasible imports and realized imports on each intertie. Eq. 20 and Eq. 21 allocate ΔI_t sequentially to Hydro-Québec long-term and then spot-market imports, reducing the remaining requirement after each step. Eq. 22 defines spot-market headroom for NYISO and NBSO based on the assumed order and limits for imports.

Before calibration:

$$I_t^{\text{net}} = \begin{cases} I_t + \min(\text{Short}_t, \bar{I}_t - I_t), & \text{Short}_t > 0 \\ \min\left\{I_t, \max\left(0, D_t - \left(G_t^{\text{low carbon}} + \sum_u G_{u,t} + d_t\right)\right)\right\}, & \text{Short}_t = 0 \end{cases} \quad \text{Eq. 17}$$

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

$$H_{j,t}^{LT} = \text{Cap}_{j,t}^{LT} \bar{CF}^{\text{imp}} - I_{j,t}^{LT} \quad \text{Eq. 18}$$

$$H_{j,t}^{\text{spot}} = \max(0, 0.95 \text{Cap}_{j,t}^{\text{spot}} - I_{j,t}^{\text{spot}}), \quad j \in \{\text{Québec}\} \quad \text{Eq. 19}$$

Allocate first to contracted Québec imports, then other Québec imports, NYISO and NBSO:

$$\Delta I_{HQ,t}^{LT} = \min(\Delta I_t, H_{HQ,t}^{LT}), \Delta I_t \leftarrow \Delta I_t - \Delta I_{HQ,t}^{LT} \quad \text{Eq. 20}$$

$$\Delta I_{HQ,t}^{\text{spot}} = \min(\Delta I_t, H_{HQ,t}^{\text{spot}}), \Delta I_t \leftarrow \Delta I_t - \Delta I_{HQ,t}^{\text{spot}} \quad \text{Eq. 21}$$

NYISO and NBSO also contribute unused headroom up to the 0.95 capacity ceiling:

$$H_{j,t}^{\text{spot}} = \max(0, 0.95 \text{Cap}_{j,t}^{\text{spot}} - I_{j,t}^{\text{spot}}), \quad j \in \{\text{NYISO}, \text{NBSO}\} \quad \text{Eq. 22}$$

2.7. Fossil fuel generation

The difference between hourly demand (SI Section 2.2) and generation from wind and solar (SI Section 2.4.1), domestic hydropower, nuclear and biomass (SI Section 2.4.2), battery discharge (SI Section 2.5), imports (SI Section 2.6), and new natural gas is the initial requirement for existing-fleet generation. This requirement depends on the pathway and is capped by the historical aggregate maximum fossil fuel generation. In pathway D, generation from newly built gas plants is installed new-gas capacity multiplied by the retained facility CF; it is subtracted before sizing the existing-fleet requirement. The new and existing fleets' emissions are then accounted for separately.

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. After allocation, the model adjusts output backward and forward through time to meet ramp limits. It then applies each

unit's minimum output. The backward adjustment uses future sampled output and does not guarantee that demand will be met.

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 CO₂, NO_x, and SO₂ 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 CAMPD, 2024). Emissions of CO, N₂O, PM₁₀, PM_{2.5}, and VOC are determined by technology-specific emissions factors tabulated in SI Table S7. The archived tables give separate 1st–99th percentiles for generation, pollutant intensity and heat input, estimated from 2013–2023 records. Dispatch samples generation from these tables. Operating emissions use the emission and heat input rates described in Section 2.13. 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.

Of 118 existing units active in 2025, 110 are represented in the hourly dispatch data. The eight units without hourly profiles remain in the supporting inventory and do not contribute to modeled generation or emissions. Missing emission and heat input rates for represented units are handled separately, as described in Section 2.13.

Missing hours within the modeled period of a represented unit initially receive zero generation before ramp and minimum-output adjustments. This differs from an entire unit lacking an hourly dispatch profile.

Historical hour-specific maxima define an aggregate fossil maximum generation capacity, but this does not reproduce intra-regional line constraints, fuel-delivery restrictions or outage schedules. Each unit initially receives its sampled generation. If the sum exceeds the capped fossil requirement, output is removed from units with the lowest sampled CF first. If the sum is below that requirement, this allocation step leaves the gap; it does not assign every unit its historical maximum. The subsequent ramp passes and minimum floor can restore output, after which storage and capped imports are reconciled. Remaining unmet demand is valued as described in Section 2.14.

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

Eq. 23 and Eq. 24 define the system-level fossil fuel requirement prior to unit-level dispatch. Eq. 23 defines residual fossil requirement R_t^{fos} as unmet hourly demand after accounting for low-carbon generation $G_t^{lowcarbon}$, imports I_t , new-gas output N_t and battery discharge d_t . Eq. 24 constrains aggregate fossil generation across all fossil units $u \in U$ to be nonnegative and capped by the minimum of this residual requirement and an exogenous total hourly fossil generation $\bar{F}_t$,

which reflects legacy fleet availability derived from historical maximum–minimum fossil generation profiles with pathway-specific retirements.

Note: Eq. 24 caps the initial fleet requirement before the unit-level ramp and minimum adjustments; it is not a cap on their final summed output.

$$R_t^{\text{fos}} = \max\{0, D_t - G_t^{\text{low carbon}} - I_t - d_t - N_t\} \quad \text{Eq. 23}$$

$$0 \leq \sum_{u \in \mathcal{U}} G_{u,t} \leq \min\{\bar{F}_t, R_t^{\text{fos}}\} \quad \text{Eq. 24}$$

For pathways without fossil retirements (Pathways A and D), the hourly fossil generation $\bar{F}_t$ 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.

2.7.2. Per unit constraints and ramping (two pass adjustment)

Eq. 25 defines whether a unit is retained under the retirement schedule. After initial hourly allocation, ramping uses a two-pass adjustment with hourly budget $\bar{R}_u$. In the backward pass (Eq. 26), preceding generation is increased if necessary to limit an upward change. In the forward pass (Eq. 27), current generation is increased to limit a downward change. Finally, Eq. 28 applies the minimum floor and rounding. No further maximum-output check or allocation is applied because this is already included in the ramping equations.

$$\chi_{u,t} = 1 \text{ for retained units; omitted for retired units} \quad \text{Eq. 25}$$

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

$$\text{Backward pass:} \quad G_{u,t-1}^* \leftarrow \max(G_{u,t}^* - \bar{R}_u, G_{u,t-1}^*) \quad \text{Eq. 26}$$

$$\text{Forward pass:} \quad G_{u,t}^* \leftarrow \max(G_{u,t-1}^* - \bar{R}_u, G_{u,t}^*) \quad \text{Eq. 27}$$

The modeled fleet contains 18 units with positive minimum output in 2025, totaling 38 MW. This equals 0.070–0.461% of hourly demand over 2025–2050 and 0.191% of mean hourly demand. The combined minimum falls to 14 MW in 2050 under the retirement schedule.

The input ramp duration is rounded upward; the hourly ramp budget is nameplate MW divided by that duration, applied over a one-hour step. There are no minimum up/down times, startup costs or binary on/off variables.

$$G_{u,t}^{\text{adj}} = \max\{G_{u,t}^*, P_u\} \quad \text{Eq. 28}$$

2.7.3. Facility level probabilistic sampling

Eq. 29 defines the initial, unconstrained hourly generation $G_{(u,t)}^{\text{raw}}$ for each unit u , which is drawn from a facility-specific empirical distribution conditioned on the day of year and hour of day. Specifically, generation is sampled from the precalculated estimates $\text{Gen}_u^{\text{tbl}}$ using the calendar label $\text{DayLabel}(t)$, the hour index $\text{Hour}(t)$, and a probabilistic draw p_ω . If the sum of raw generation across all units exceeds the system-level fossil generation $\bar{F}_t$, generation is reduced prior to applying ramping constraints, by curtailing the lowest-capacity-factor units first, to ensure $\sum_u G_{(u,t)} \leq \bar{F}_t$.

Day of year and hour of day represent seasonal and daily variation. Weekday/weekend effects are not modeled separately.

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

$$G_{u,t}^{\text{raw}} = \text{Gen}_u^{\text{tbl}}(\text{DayLabel}(t), \text{Hour}(t), p_\omega) \quad \text{Eq. 29}$$

If $\sum_u G_{u,t}^{\text{raw}} > \bar{F}_t$, reductions from the lowest-capacity-factor units first ensure $\sum_u G_{u,t} \leq \bar{F}_t$ before ramp passes.

2.8. 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. Reported surplus is the generation remaining after demand and battery charging. It includes additional fossil generation caused by ramp adjustments and cannot be assigned entirely to renewables. 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. Unmet demand is valued at \$3,500/MWh. Figure S2 shows ISO-NE's variable cost curve for context (Potomac Economics, 2024).

2.8.1. Energy balance

Eq. 1 in Section 2.3 requires the hourly electricity accounting to balance. Electricity available in each hour includes non-fossil generation, fossil generation, imports, and battery discharge. If these sources do not meet demand, the model records the gap as unmet demand, $Short_t$. Electricity is used to meet demand, D_t , charge batteries, c_t , or is recorded as curtailment, $Curt_t$. In simple form: available electricity + $Short_t = D_t + c_t + Curt_t$.

2.8.2. 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 auxiliary variables in the system energy balance.

Eq. 1 (Section 2.3) enforces hourly energy balance. Eq. 30 and Eq. 31 formally define curtailment $Curt_t$ and unmet demand $Short_t$ as nonnegative residuals that close the balance. Eq. 32 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. 33), 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. 34), 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.

$$Curt_t = \max\{0, G_t^{low\ carbon} + I_t + N_t + \sum_u G_{u,t} - D_t - c_t\} \quad Eq. 30$$

$$Short_t = \max\{0, D_t - G_t^{low\ carbon} - I_t - d_t - \sum_u G_{u,t} - N_t\} \quad Eq. 31$$

The diagnostic residual must be approximately zero:

$$BalRes_t = \left(G_t^{low\ carbon} + I_t + \sum_u G_{u,t} + d_t + N_t \right) - (D_t + c_t + Curt_t - Short_t) \quad Eq. 32$$

Iteration over battery storage and imports

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

$$G_t^{fos} \equiv \sum_u G_{u,t}^{adj} \quad Eq. 33$$

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:

Each pathway and simulation combination contains 227,904 regional hours; the maximum recorded hourly balance residual is 0.005 MWh. These checks do not verify least-cost operation, unit commitment or power flow. Storage is replayed after unit adjustment under the same clean-generation charging guard, followed by the final import headroom allocation.

$$\text{SOC}_t^{\text{cal}} = \min\{\max(\rho \text{SOC}_{t-1}^{\text{cal}} + \eta c_t^{\text{cal}} - \frac{1}{\eta} d_t^{\text{cal}}, 0), E_{\max,t}\} \quad \text{Eq. 34}$$

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

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

2.9. CAPEX, FOM, VOM, and fueling costs

We calculate generation capital expenditures (CAPEX), fixed operations and maintenance (FOM), variable operations and maintenance (VOM), and fuel costs using the supplied 2024 NREL ATB input. Non-SMR technologies use mature-market assumptions and SMRs use nascent-market assumptions, with a 30-year recovery period. SMRs can enter service from 2030; existing large nuclear generation is represented from 2025. ATB monetary values are converted from 2022 to January-2024 dollars using a CPI factor of 1.05834. CAPEX includes land acquisition. These costs are then calculated at 1.5%, 2% and 2.5% using all 1,000 simulations (Tables S10–S12).

For each simulation, we sample each cost coefficient from a uniform distribution between its lower and upper bounds. Each sampled value is then used across all pathways and years. Sampled cost categories include generation CAPEX and O&M, non-fossil fuel, import purchases, intertie costs and Canadian hydropower costs where lower and upper estimates are available (Table S6). Fossil-fuel prices are fixed by fuel and year.

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 Québec. 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. Intertie CAPEX and FOM use separate uniform draws over the specified caps, shared across pathways and years.

Fuel costs equal generation multiplied by fuel-specific coefficients. Nuclear and biomass use mature-market ATB assumptions, and SMRs use nascent-market assumptions. The fossil fuel-price table supplies fixed fuel/year coefficients. Fossil fuel costs vary with generation and fuel mix, while non-fossil fuel and variable-O&M coefficients are sampled where capped cases are available (Table S6).

As we describe in more detail in SI Section 2.11, 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 B3(2) costing method, in which we apportion a fraction of Canada-side costs to the hydropower-dependent B3 pathway (CAPEX and FOM costs incurred from new large Canadian hydropower plants in Québec), 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 S6. 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. 36 defines annual capital expenditures $\text{Cost}_y^{\text{CAPEX}}$ 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. 37 defines annual fixed operations and maintenance costs $\text{Cost}_y^{\text{FOM}}$ as the sum of fixed costs for all assets A_y operating in year y .

Eq. 38 defines hourly variable operations and maintenance costs $\text{Cost}_t^{\text{VOM}}$ as the sum over all generation technologies g of technology-specific variable cost coefficients v_g multiplied by hourly generation $G(g,t)$. Eq. 39 defines hourly fueling costs $\text{Cost}_t^{\text{fuel}}$ as the sum of unit-level fuel costs f_u multiplied by adjusted fossil generation $G_{(u,t)}^{\text{adj}}$, plus technology-level fuel costs for nuclear, biomass, and SMR generation, which are modeled at the aggregate technology level.

For each simulation, technology and cost category, we draw a uniform value between zero and one and use it to interpolate between the lower and upper cost estimates, as defined in Eq. 35. That draw is shared across pathways and years. Different coefficients are sampled independently; inputs with a single value remain fixed (Table S6).

$$c_{s,k,y} = c_{k,y}^{\text{lower}} + U_{s,k} \times (c_{k,y}^{\text{upper}} - c_{k,y}^{\text{lower}}), \quad U_{s,k} \sim \text{Uniform}(0, 1) \quad \text{Eq. 35}$$

In this formula, s is simulation, k is the technology and cost category, and y is year. A single $U_{s,k}$ is applied across pathways and years; different technology and cost category pairs are sampled independently. The uniform distribution is an assumption of this analysis.

Table S18 reports standard deviations for 14 cost categories across eight pathways, with two for B3.

$$C_{s,p,y}^{CAPEX} = \Sigma_k \Delta K_{p,k,y} C_{s,k,y}^{CAPEX} \quad \text{Eq. 36}$$

$$C_{s,p,y}^{FOM} = \Sigma_k K_{p,k,y} C_{s,k,y}^{FOM} \quad \text{Eq. 37}$$

$$C_{s,p,t}^{VOM} = \Sigma_k G_{s,p,k,t} C_{s,k,y(t)}^{VOM} \quad \text{Eq. 38}$$

$$C_{s,p,t}^{fuel} = \Sigma_f G_{s,p,f,t} f_{f,y(t)}^{fixed} + \Sigma_n G_{s,p,n,t} C_{s,n,y(t)}^{fuel} \quad \text{Eq. 39}$$

2.10. Costs of imports from other jurisdictions

We estimated import costs from NYISO to be between 0.78¢ to 2.41¢ kWh-1 (2024-USD) as a source range 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 cap estimate, while a similar uncertainty range as applied for NYISO yields a lower cap 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.

Import purchase coefficients are sampled over the retained jurisdiction specific caps, with one draw per simulation and link shared across pathways and years. New intertie CAPEX and fixed O&M use separate sampled coefficients. Purchase costs also vary with delivered MWh.

Eq. 40 defines hourly import costs $Cost_t^{imports}$ as the sum over all importing jurisdictions j of jurisdiction-specific levelized import cost coefficients κ_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.

$$C_{s,p,t}^{imports} = \Sigma_j I_{s,p,j,t} C_{s,j,y(t)}^{purchase} \quad \text{Eq. 40}$$

2.11. 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). For imports that use existing hydropower and transmission capacity, a U.S.-focused costing method may reasonably include only U.S. transmission investments and the cost of purchased imports. However, where increased U.S. imports induce new Canadian hydropower development, a broader consequential costing requirement can include generation-side costs and impacts in

Canada, including reservoir construction, fixed operations and maintenance, and methane (CH₄) emissions from new reservoirs (Calder et al., 2022; Curran et al., 2005; Earles & Halog, 2011; Ekvall, 2019).

Pathway B3 assumes that approximately 9 GW of new hydroelectric generation in Canada would be required to support increased exports to New England (Commonwealth of Massachusetts, 2020). We therefore evaluate two costing methods for B3. B3(1) applies an import-cost costing method in which methane emissions are valued proportionally to hourly hydropower imports from Québec. These costs also include U.S. transmission infrastructure and levelized costs of imported electricity, as described in SI Sections 2.6 and 2.10. This provides a lower-cap estimate from the perspective of New England electricity-system planning. B3(2) applies a broader social-cost costing method: import costs are replaced by prorated CAPEX and fixed O&M for new Canadian hydropower infrastructure, and indirect climate damages from reservoir CH₄ emissions are added, as described in SI Sections 2.11 and 2.12. Import payments are excluded in B3(2) because they are transfers between actors rather than net social costs of the energy system.

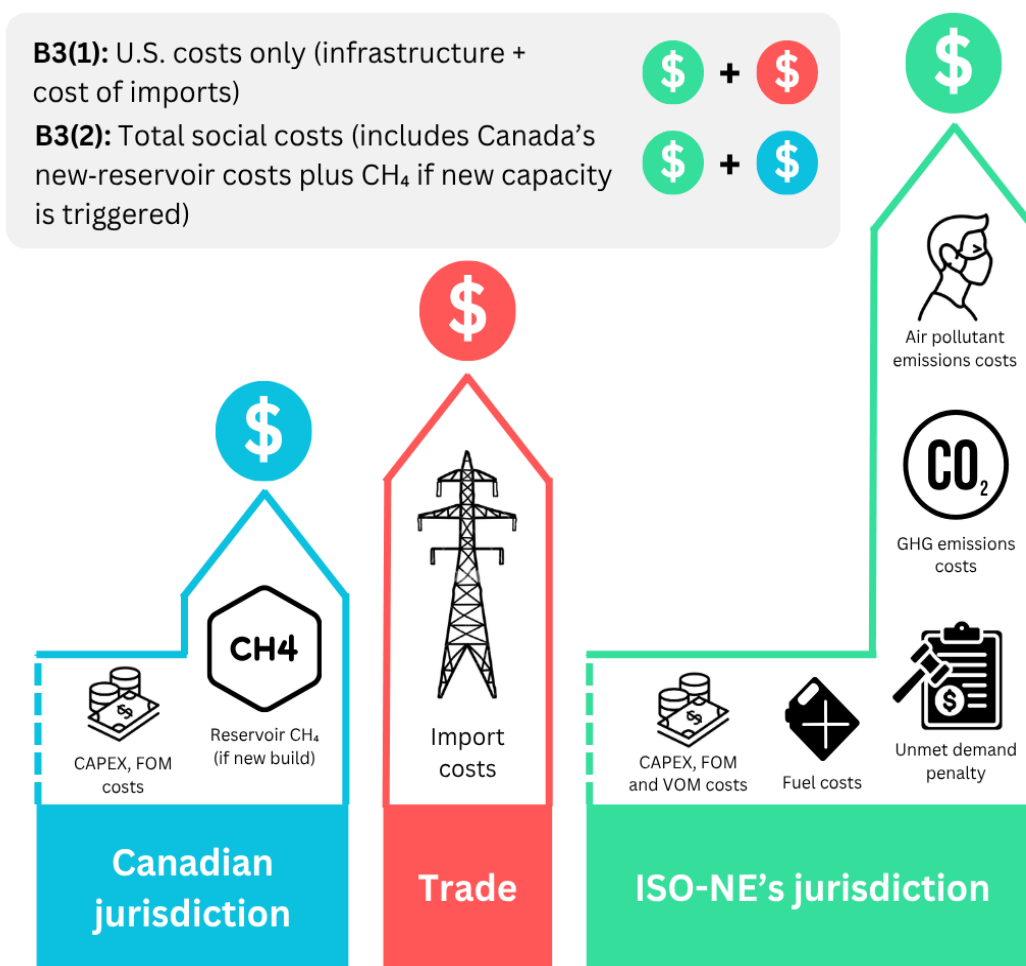


Figure S1: For the B3 pathway, costing method B3(1) includes U.S. transmission infrastructure and import costs. Costing method B3(2) replaces Québec import payments with the retained Canadian hydropower CAPEX, fixed O&M, variable O&M and reservoir CH₄ costs. NYISO and NBSO payments remain. Other pathways exclude Canadian generation-side impacts under the retained attribution assumption.

Other modeled pathways do not assume sufficient incremental Canadian hydropower demand to induce new reservoir construction. For those pathways, we do not attribute impacts from existing Canadian reservoirs to incremental imports. This avoids the over-attribution problem common in attributional costing, where impacts of existing infrastructure are assigned to a marginal intervention despite no causal link between the intervention and the original infrastructure development (Calder et al., 2020, 2022; Curran et al., 2005; Gazar et al., 2024).

The B3(1) and B3(2) costing methods use the same New England dispatch with different cost assumptions. The dispatch model does not determine whether additional imports require reservoir construction, change reservoir operations or displace exports to other markets.

For B3(2), reservoir CH_4 emissions are estimated using reported emissions from three existing Québec reservoirs: Eastmain, Robert-Bourassa, and LaForge-1 based on Delwiche et al. (2022). Because emissions depend on reservoir age, trophic status, surface area, and other site-specific characteristics, and because the location and characteristics of any future reservoir are uncertain, we pool the reported range into a uniform distribution and scale emissions to the hydropower generation required for B3. This yields an estimated range of 0.16–1.22 kg CH_4 -C MWh^{-1} imported. Facility-specific reservoir methane assumptions are provided in SI Table S9.

Canadian cost coefficients are sampled within the specified ranges using the same draw across years. At 2%, the B3(2) standard deviations are \$11.322 billion for CAPEX, \$16.854 billion for fixed O&M, \$0.001 billion for variable O&M and \$0.953 billion for methane damages (Table S18). For Canadian hydropower, additional hydro capacity is derived from B3 versus B1 intertie additions, limited by imported energy and allocated against the specified build schedule. Fixed O&M uses the full Québec capacity divided by the hydro CF, while variable O&M and methane use delivered Québec MWh.

2.12. 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_2O -1 in 2024 USD, escalating over time (U.S. EPA, 2023). These costs are applied to fossil fuel GHG emissions described in SI Section 2.13. As described in SI Section 2.11, we consider two alternative costing methods for the emission impacts from new hydroelectric generation in Québec (i.e. whole generation/transmission system prorated to New England usage vs. direct cost). The B3 pathway considers substantially increased hydroelectric imports such that new generation capacity is triggered. We analyze this pathway using the B3(1) and B3(2) costing methods described in Section 2.11.

Eq. 41 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 $E_t^{(g)}$.

Under costing method B3(1), methane emissions are valued proportionally to hourly hydropower imports from Québec, represented by $\theta_{res} I_t^{HQ}$. Under costing method B3(2), methane emissions associated with new reservoir hydropower in Québec are valued based on installed reservoir capacity through an additional reservoir-related methane term $E_{(res,t)}^{CH_4}$. B3(1) excludes Canadian generation-side methane. B3(2) adds an attributed reservoir methane term to the same fossil GHG costings. Other pathways do not include new Canadian reservoir impacts under the

retained capacity. Equation 41 distinguishes these costing methods. Reservoir allocation is described in Section 2.11.

$$\text{Cost}_t^{\text{GHG}} = \begin{cases} s_{\text{CO}_2,y}^{\text{GHG}} E_t^{\text{CO}_2} + s_{\text{CH}_4,y}^{\text{GHG}} (E_t^{\text{CH}_4} + E_{\text{res},t}^{\text{CH}_4}) + s_{\text{N}_2\text{O},y}^{\text{GHG}} E_t^{\text{N}_2\text{O}} & B3(1) \\ s_{\text{CO}_2,y}^{\text{GHG}} E_t^{\text{CO}_2} + s_{\text{CH}_4,y}^{\text{GHG}} (E_t^{\text{CH}_4} + \theta_{\text{res}} I_t^{\text{HQ}}) + s_{\text{N}_2\text{O},y}^{\text{GHG}} E_t^{\text{N}_2\text{O}} & B3(2) \\ s_{\text{CO}_2,y}^{\text{GHG}} E_t^{\text{CO}_2} + s_{\text{CH}_4,y}^{\text{GHG}} E_t^{\text{CH}_4} + s_{\text{N}_2\text{O},y}^{\text{GHG}} E_t^{\text{N}_2\text{O}} & \text{Other pathways} \end{cases} \quad \text{Eq. 41}$$

In all other pathways, hydropower imports are assumed insufficient to induce new reservoir development, and only fossil fuel emissions are valued.

2.13. Air pollutant emissions costs

Equation 42 sums facility pollutant masses multiplied by their assigned marginal damage coefficients. AP4 covers NO_x, SO₂, PM_{2.5} and VOC. In the cost module, PM₁₀ equals total particulate mass minus PM_{2.5}. We use the AP3 damage coefficient for PM₁₀ because the corresponding coefficient is unavailable in the AP4 tables used here. CO uses a separate published cost range. In Eq. 42, q spans these six pollutants, M is in metric tonnes and MD is in 2024 USD per metric tonne. Table S8 identifies the facility matches, county proxies and reference facilities for new plants. Costs are aggregated annually before discounting.

$$C_{s,p,t}^{\text{air}} = \sum_i \sum_q M_{i,q,s,p,t} MD_{i,q} \quad \text{Eq. 42}$$

For each facility, annual pollutant mass is multiplied by the assigned marginal damage coefficient. EGU matches, county proxies and reference-facility assignments for hypothetical new gas facilities are identified in Table S8. Pollutant mass and coefficient units are converted consistently before multiplying. Damages are attributed to the source county and are not interpreted as impacts on that county's residents.

The AP4 coefficients use the supplied 2017 emissions, population and mortality inputs and a 2020-dollar cost basis. We convert them to the January-2024 price basis. Damage-model and source-proxy uncertainty are not sampled. PM controls and fine/coarse particle treatment remain limitations.

For existing units, hourly CO₂, NO_x, and SO₂ emissions and heat input are calculated from final adjusted generation using emission and heat input rates estimated from 2013–2023 CAMPD unit records. For each unit and measure, we compare three estimated emission and heat input rates: (1) a fixed unit-average emission and heat input rate, calculated as total observed emissions or heat input divided by total generation; (2) a load-dependent emission and heat input rate, calculated within load categories; and (3) a load-and-ramp-dependent emission and heat input rate, calculated within combined load and ramp categories. The selected emission and heat input rates are based on data coverage, as described below.

Eq. 43 defines unit-level emission mass as adjusted generation multiplied by the selected emission and heat input rate at the unit's final load and ramp category. Eq. 44 sums the existing-unit masses; new gas is calculated separately and added to system GHG and air-pollution costs. This is not the same-percentile pairing of independently calculated generation and intensity quantiles.

$$E_{u,t}^k = \hat{\varphi}_{ku}(b_t, r_t) Gadj_{u,t} \quad Eq. 43$$

$$E_t^k = \sum_u E_{u,t}^k \quad Eq. 44$$

Because historical emissions data are incomplete for a subset of units and operating conditions, Eq. 45 identifies the selected supported estimated emission and heat input rate: unit-specific load/ramp emission and heat input rate, unit-specific load-based emission and heat input rate, or unit-average emission and heat input rate, with a documented reference unit or audited fuel/unit-type fallback where unit history is insufficient. The structure is selected using held-out performance and coverage checks rather than always choosing the most detailed category. Unsupported cells within a selected structure revert to the unit-average emission and heat input rate.

The selected estimated emission and heat input rate is applied to the final adjusted generation and change from the previous hour; a documented fixed estimate is used when there is not enough unit-specific data:

$$\hat{\varphi}_{ku}(b_t, r_t) \leftarrow \text{selected supported unit emission and heat input rate or audited} \quad Eq. 45$$

Historical full-hour records from 2013–2023 with positive generation, finite nonnegative pollutant mass and accepted measurement/calculation indicators are used for calibration. Duplicate records are removed. Load categories are 0–25%, 25–50%, 50–75%, 75–100% and above 100% of nameplate capacity; ramp categories are decreasing, approximately steady, increasing or unknown, using $\pm 10\%$ of nameplate capacity per hour and consecutive eligible observations.

$$\hat{\varphi}_{ku}, b, r = \frac{\sum_{h \in H_{u,b,r}} M_{ku,h}}{\sum_{h \in H_{u,b,r}} G_{u,h}} \quad Eq. 46$$

Emission and heat input rates are generation-weighted mass per MWh, not arithmetic means of hourly intensities. Unit models require at least 200 eligible hours and 20 dates; operating cells require at least 100 hours and 20 dates. Training through 2020 and validation on 2021 select

fixed, load-only or load/ramp structure by hourly mass-prediction error, preferring the simpler structure on ties. At least 100 validation observations are required. A separate evaluation refits through 2021 and tests 2022–2023; the final set of estimated emission and heat input rates is recalculated from all eligible 2013–2023 observations using the selected approach.

$$\hat{E}_{ku,t} = G_{adj,u,t} \times \hat{\varphi}_{ku} \left(b(G_{adj,u,t}), r(G_{adj,u,t} - G_{adj,u,t-1}) \right) \quad Eq. 47$$

Zero generation gives zero modeled operating emissions. This improves the representation of partial load and historical ramp conditions where supported, but does not separately model startup fuel, startup emissions, fuel-delivery constraints, changes in pollution controls, facility aging or future degradation. Other pollutants retain the technology/fuel factors in Table S7. No distribution of emission and heat input rates is sampled during dispatch; the selected estimated emission and heat input rate is applied directly, avoiding hourly model fitting.

Operating emissions (Eq. 47) equal final adjusted generation multiplied by the unit emission and heat input rate, which varies with load and ramp conditions where supported. Separately calculated generation and pollutant-intensity percentiles do not identify historical generation–emission pairs.

2.14. Unmet demand penalty costs

During periods of capacity scarcity, when available generation 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 under the two-pass adjustment; there is no objective function that minimizes shortage or optimizes battery charging. Eq. 48 calculates hourly shortage penalties by multiplying unmet demand by \$3,500/MWh (2024 USD) (Potomac Economics, 2024).

$$\text{Cost}_t^{\text{short}} = \pi_{\text{short}} \cdot \text{Short}_t^{(\text{cal})} \quad Eq. 48$$

2.15. Direct costs

Eq. 49 defines timestep-level direct operating costs $\text{Cost}_t^{\text{direct}}$ as the sum of all costs that vary with hourly system operation, including variable operations and maintenance $\text{Cost}_t^{\text{VOM}}$, fuel expenditures $\text{Cost}_t^{\text{fuel}}$, and electricity import costs $\text{Cost}_t^{\text{imports}}$. These costs depend on realized generation, fuel use, and imports in each hour.

Eq. 50 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 $\text{Cost}_y^{\text{CAPEX}}$, which occur in the year new generation or transmission assets are commissioned, and fixed operations and maintenance costs $\text{Cost}_y^{\text{FOM}}$, 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.

$$\text{Cost}_t^{\text{direct}} = \text{Cost}_t^{\text{VOM}} + \text{Cost}_t^{\text{fuel}} + \text{Cost}_t^{\text{imports}} \quad \text{Eq. 49}$$

$$\text{Cost}_y^{\text{direct}} = \sum_{t \in y} \text{Cost}_t^{\text{direct}} + \text{Cost}_y^{\text{CAPEX}} + \text{Cost}_y^{\text{FOM}} \quad \text{Eq. 50}$$

2.16. Indirect costs

Eq. 51 defines timestep-level indirect costs $\text{Cost}_t^{\text{indirect}}$ 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. 52 aggregates hourly indirect costs across all timesteps in year y to obtain total annual indirect costs, ensuring that climate damages, air quality impacts, and reliability penalties are consistently accounted for over time.

$$C_{s,p,t}^{\text{indirect}} = C_{s,p,t}^{\text{GHG}} + C_{s,p,t}^{\text{air}} + C_{s,p,t}^{\text{short}} \quad \text{Eq. 51}$$

$$\text{Cost}_y^{\text{indirect}} = \sum_{t \in y} \text{Cost}_t^{\text{indirect}} \quad \text{Eq. 52}$$

2.17. Total system cost and NPV

Eq. 53 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.

$$\text{Cost}_y = \text{Cost}_y^{\text{direct}} + \text{Cost}_y^{\text{indirect}} \quad \text{Eq. 53}$$

$$\text{NPV} = \sum_{y \in \mathcal{Y}} \frac{\text{Cost}_y}{(1+r)^{y-y_0}} \quad \text{Eq. 54}$$

Eq. 54 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.

3. Monte Carlo analysis

ISO-NE supplies hourly capacity-factor profiles for solar, onshore wind and offshore wind at seven annual-output percentiles (1, 5, 10, 50, 90, 95 and 99%). These profiles originate from a common weather-modeling framework and preserve the modeled relationships among renewable resources (ISO-NE, 2024a). PHASED interpolates the supplied profiles to indices 1–99 and propagates the selected renewable realization through hourly dispatch.

Here, preservation of renewable dependence refers to the relationships among annual average capacity factors. Each sampled renewable realization uses a corresponding combination of solar and wind availability derived from the joint ISO-NE profiles. This does not require reproduction of every original hourly weather sequence.

For each simulation, in addition to existing fossil fuels, renewable and import capacity factors are drawn for each hour and applied to the corresponding day of year and hourly profiles. The same sampled inputs are used for all pathways. This preserves correlations across sources of uncertainty between pathway outcomes, but does not establish dependence between different technologies, demand and import availability. Cost coefficients use one draw per simulation and coefficient, shared across pathways and years (Section 2.9).

$$\mathbf{CF}_{\text{Solar},t}(\omega) = \mathbf{CF}_{\text{Solar}}^{\text{tbl}}(\text{DayLabel}(t), \text{Hour}(t), p_\omega) \quad \text{Eq. 55}$$

$$\mathbf{CF}_{\text{Wind}_{\text{on}},t}(\omega) = \mathbf{CF}_{\text{Wind}_{\text{on}}}^{\text{tbl}}(\text{DayLabel}(t), \text{Hour}(t), p_\omega) \quad \text{Eq. 56}$$

$$\mathbf{CF}_{\text{Wind}_{\text{off}},t}(\omega) = \mathbf{CF}_{\text{Wind}_{\text{off}}}^{\text{tbl}}(\text{DayLabel}(t), \text{Hour}(t), p_\omega) \quad \text{Eq. 57}$$

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

$$\mathbf{CF}_{j,t}^{\text{spot}}(\omega) = \mathbf{CF}_j^{\text{tbl}}(\text{DayLabel}(t), p_\omega) \quad \text{Eq. 58}$$

For simulation s , each pathway p is evaluated using the same indexed input draws. The paired cost difference is $\Delta C_{p,\beta,s} = C_{p,s} - C_{\beta,s}$. Using the same sampled inputs across pathways allows pathway outcomes to be compared under matched input conditions. An absolute outcome is one pathway's cost under a sampled input set; a paired difference contrasts two pathway outcomes under that same set. We report both distributions. The identity $\text{Var}(C_p - C_\beta)$ shows that pairing

narrows the difference relative to independently sampled pathway outcomes when their common-input covariance is positive. Narrow differences or stable rankings are not guaranteed.

$$\text{Var}(\mathbf{C}_p - \mathbf{C}^{B1}) = \text{Var}(\mathbf{C}_p) + \text{Var}(\mathbf{C}^{B1}) - 2 \text{Cov}(\mathbf{C}_p, \mathbf{C}^{B1}) \quad \text{Eq. 59}$$

B1 is the primary comparison for every pathway, consistent with the ISO-NE/PHASED benchmark. Table S19 reports means, SDs, empirical P05–P95 and sign counts for paired differences from B1. Shared draws narrow differences when pathway effects are positively correlated; they need not narrow every difference.

We quantify additive contributions to total-cost variance using the covariance of each cost category with total cost:

$$V_k = \frac{\text{Cov}(\mathbf{C}_k, \mathbf{C}_{\text{total}})}{\text{Var}(\mathbf{C}_{\text{total}})}, \quad \sum_k V_k = 1 \quad \text{Eq. 60}$$

For each displayed cost category, the reported contribution is $100 \times \text{Cov}(\text{category cost, total cost}) / \text{Var}(\text{total cost})$. The cost categories add to the total, so their contributions sum to 100%, including any negative contributions induced by covariance. These are contributions of cost outputs to total-cost variance. They are not independent causal effects or global sensitivity indices for the model inputs. Figure S6 and Table S18 use all 1,000 simulations and the same cost category definitions.

All complete simulations are included. Completeness checks cover pathway and simulation combinations, annual outputs and represented-facility coverage.

The simulation uncertainty ranges are conditional on the prescribed portfolios, demand forecast, historical operating data, coefficient ranges and dispatch rules. They exclude demand forecast error, fossil-fuel-price shocks, explicit forced outages, extreme-event dependence, construction delays and uncertainty in fitted emission rates or AP4 coefficients. Independent cost coefficients are a modeling assumption. The central 90% simulation range is therefore not a confidence interval covering all possible future outcomes.

4. Model checks and annual benchmarks

Figure S4 compares mean annual B1 generation across 1,000 simulations with the ISO-NE High Electrification scenario. The comparison covers solar, onshore wind, offshore wind and total clean generation from those resources plus hydro, existing nuclear and Québec imports over 2025–2050.

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

4.1. Total annual load calculation

Total annual load is the sum of fixed hourly demand within each year. Gross generation plus net imports differs from served load by battery charging/discharging, losses, surplus and shortage. The annual demand calculation is:

$$D_y^{annual} = \sum_{t \text{ in } y} D_t \quad \text{Eq. 61}$$

Here D_t is hourly demand and the sum covers the modeled year. Generation and imports are reported separately; Eq. 1 identifies the storage and surplus terms required to reconcile them with demand.

4.2. Interpretation of annual comparisons

The benchmark compares matching annual resource quantities over the same years.

Hourly operating validation requires the retained hourly partitions and the exact operating-model artifacts used for the set of simulations. Annual energy and pollutant reconciliation is reported separately.

B1 mean direct costs were \$357.54 billion, approximately 4.1% higher than the ISO-NE estimate of \$343.57 billion (2024 USD, 2025–2050, 2% discount rate; Table S13). These estimates are similar in magnitude, although differences in included cost categories and cost timing limit direct comparability.

5. U.S. fossil fuel generator database

We developed a national database of hourly-scale probabilistic generation and emissions characteristics for 4,633 generating units at 1,379 fossil fuel power plant facilities across the contiguous United States. For each unit, synthetic hourly probability distributions (1st–99th percentiles) were fitted by day-of-year and hour-of-day using 2013–2023 EPA CAMPD data, covering generation (MWh), CO₂, NO_x, and SO₂. The supplied New England dispatch metadata contain 152 units, of which 118 are active by the 2025 retirement filter and 110 are represented in the 2025 dispatch output; although this application uses the regional subset, the full national database is provided to support application of PHASED (Probabilistic Hourly Assessment of Scenarios for Electrical Decarbonization) to other U.S. regions. The database, individual plant reports, state and national bulk downloads, are linked at <https://amirgazar.github.io/us-powerplants-phased/index.html>.

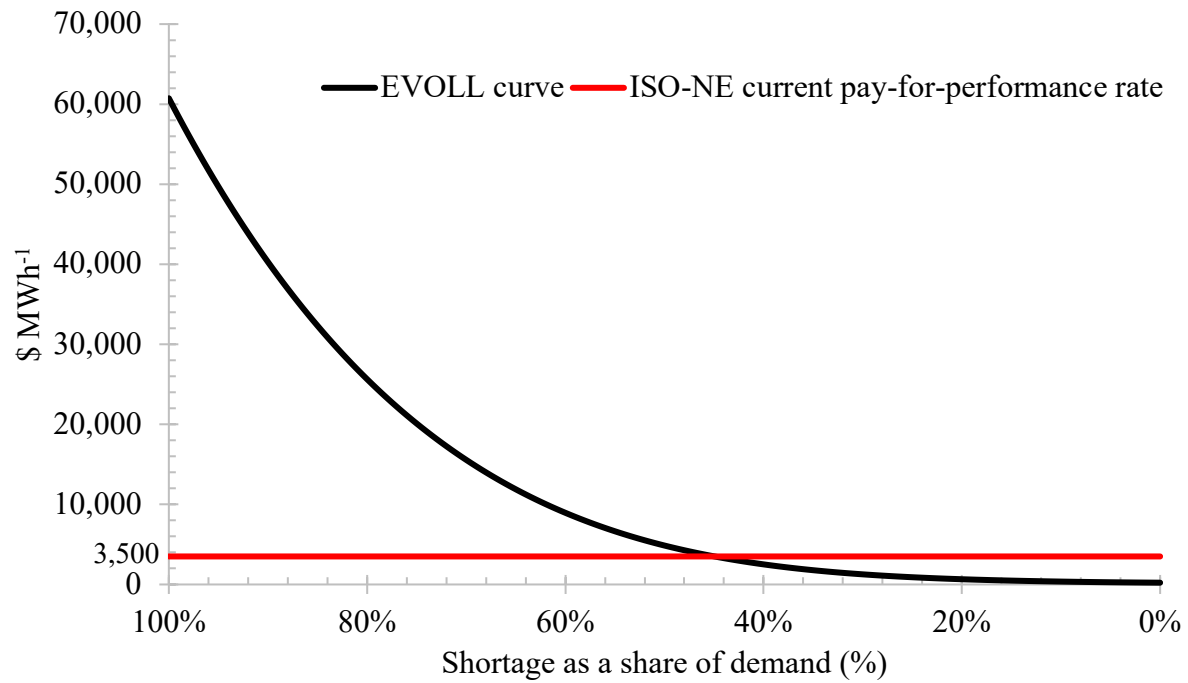


Figure S2: ISO-NE pay-for-performance rates and value-of-lost-load curve, adapted from the 2023 Assessment of the ISO New England Electricity Markets prepared by Potomac Economics for ISO-NE (Potomac Economics, 2024). The value-of-lost-load curve is shown for context only; unmet demand in PHASED is valued using a fixed penalty of \$3,500/MWh.

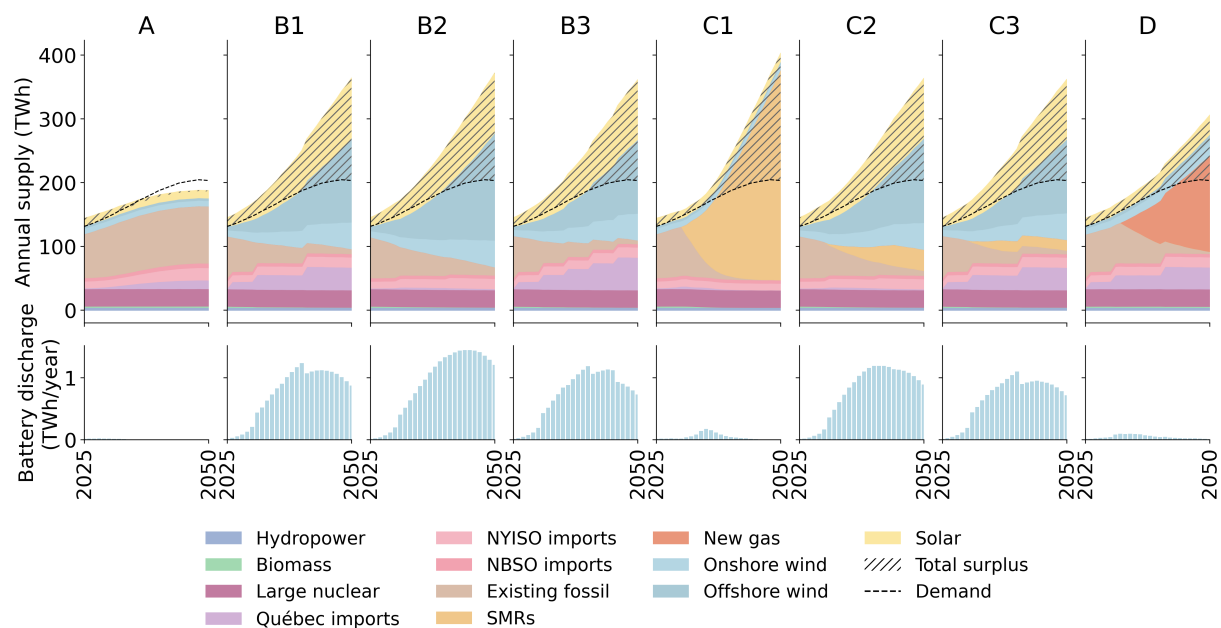


Figure S3: Mean annual generation by technology and import link over all 1,000 simulations, with battery discharge shown below each pathway. The dashed line is demand. Hatching identifies total curtailments, which may include fossil fuel output restored by operating constraints and is not assigned to an individual renewable technology.

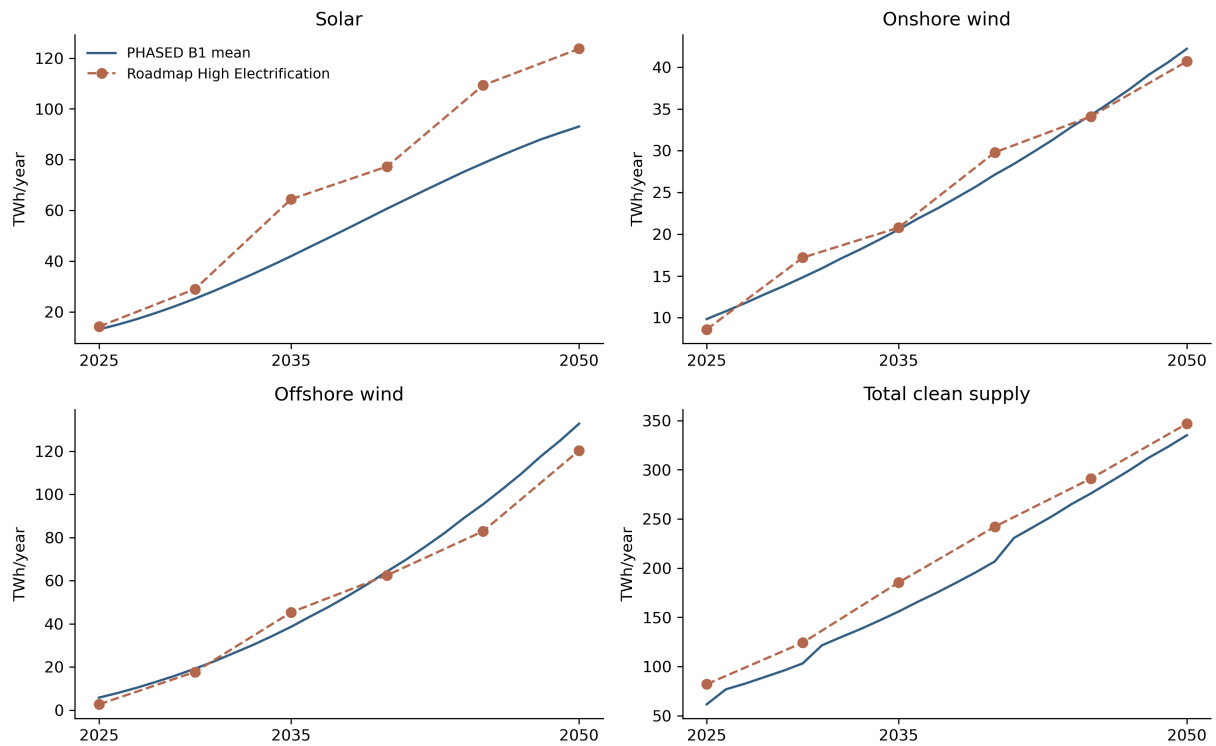


Figure S4: Annual B1 generation compared with the ISO-NE High Electrification scenario for 2025–2050. Panels show solar, onshore wind, offshore wind and total clean generation, including hydro, existing nuclear and Québec imports. Solid lines show PHASED means across 1,000 simulations; dashed lines with points show ISO-NE values (Commonwealth of Massachusetts, 2020).

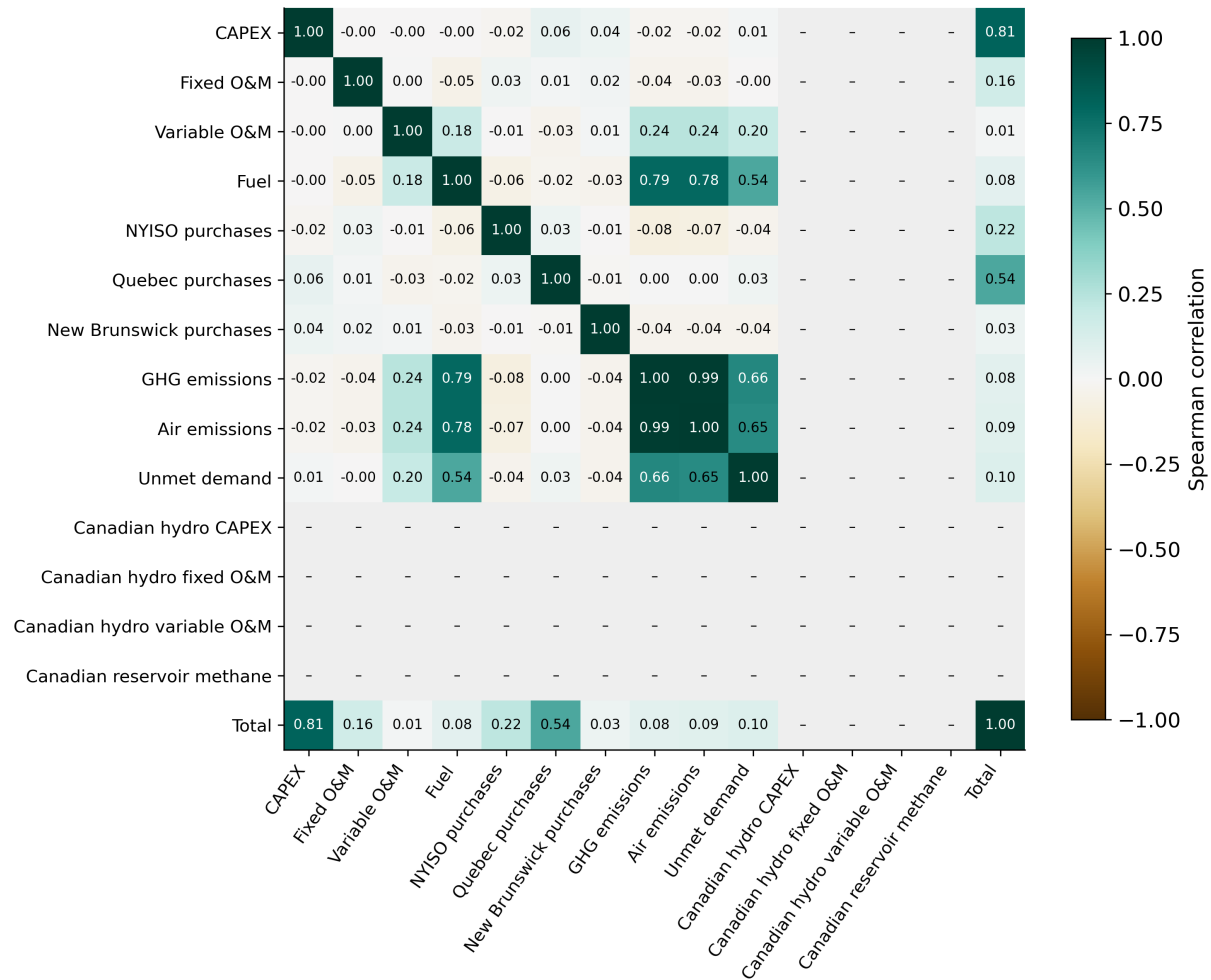


Figure S5: Spearman correlations among B1 cost categories across 1,000 simulations at a 2% discount rate.

Positive values indicate cost categories that increase together; negative values indicate cost categories that vary in opposite directions.

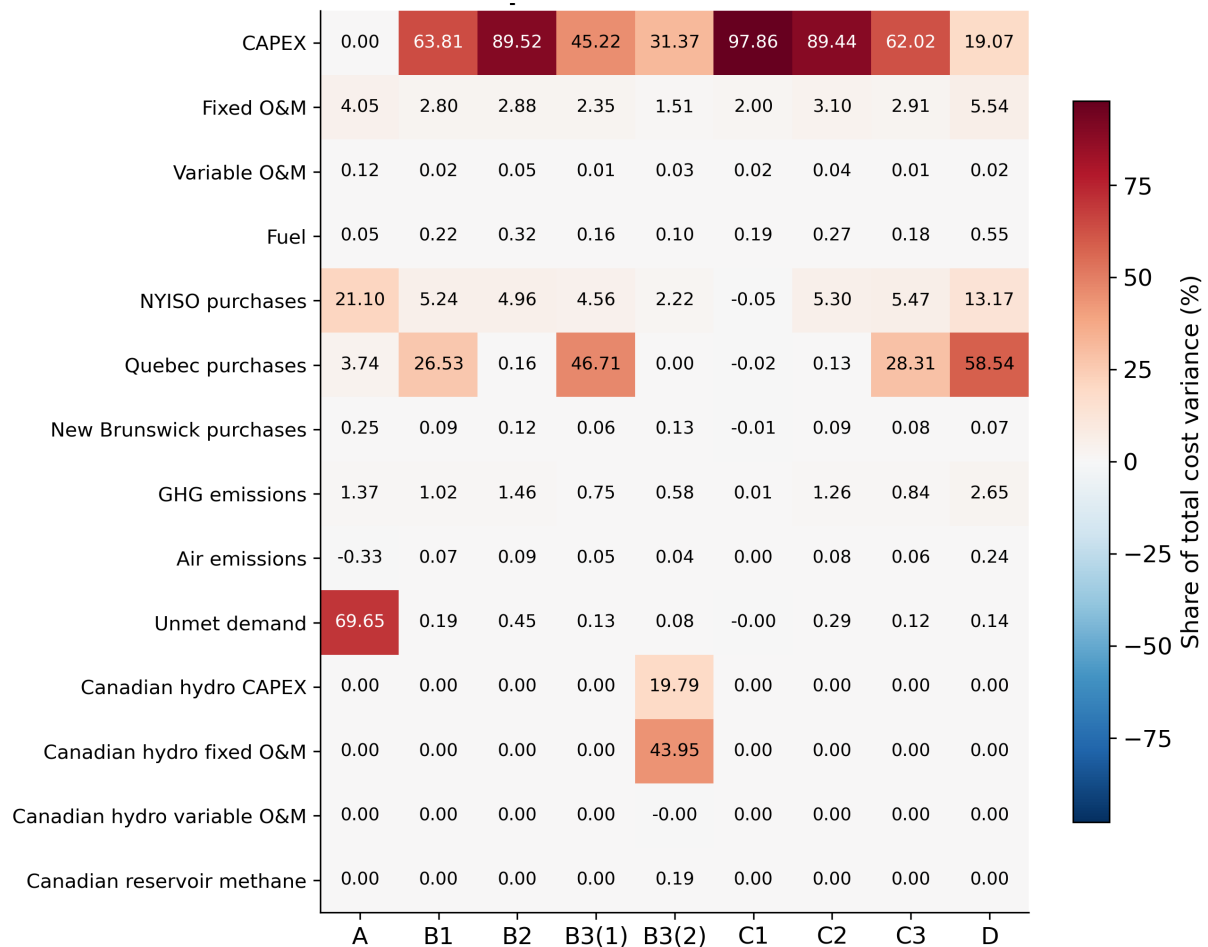


Figure S6: Contributions to total-cost variance across 1,000 simulations at 2%.

Contributions sum to 100% within each pathway and may be negative when a cost category varies in the opposite direction to total cost.

Table S2: Annual capacity schedules for eight decarbonization pathways, including the 2024 baseline and 2025–2050 projections.

Source capacity schedules are in MW. Storage is operated hourly using the limits described in SI Section 2.5.

Pathway A												
Year	Large nuclear	Hydropower	Biomass	Solar	Onshore Wind	Offshore Wind	Small modular reactor	New natural gas	Imports from Hydro-Québec	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-Québec	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-Québec	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-Québec	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-Québec	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-Québec	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-Québec	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- Québec	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 characteristics, primary fuels, ramp categories, retirement years and mean emission rates for the New England fossil-fuel units in the model input. This table includes each facility's nameplate capacity (MW) and capacity factor (in brackets), ramp designation, projected retirement year, and average CO₂, NO_x, SO₂, and heat input rates per MWh of generation. Note this retirement schedule in this study applies to all pathways except A and D. The table reports the unit inventory and historical or estimated average rates. Sourced from U.S. EPA CAMPD records for 2013–2023, supplemented by facility metadata from EIA Form 860 and U.S. EPA eGRID.

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Alfred L Pierce Generating Station Fuel: Pipeline Natural Gas	6635 [AP-1]	New Haven County, CT	84 [0.62]	1H	2062	0.63	0.56	0.01	6.29
Bellingham Fuel: Pipeline Natural Gas	10307 [1]	Norfolk County, MA	257.4 [0.37]	12H	2046	0.67	0.88	0.03	4.11
Bellingham Fuel: Pipeline Natural Gas	10307 [2]	Norfolk County, MA	257.4 [0.37]	12H	2046	0.68	0.92	0.03	4.24
Bellingham Power Generation LLC Fuel: Pipeline Natural Gas	55211 [2]	Norfolk County, MA	289 [0.45]	12H	2057	0.65	0.1	0.01	4.9

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Bellingham Power Generation LLC Fuel: Pipeline Natural Gas	55211 [1]	Norfolk County, MA	289 [0.44]	12H	2057	0.66	0.1	0.01	4.93
Berkshire Power Fuel: Pipeline Natural Gas	55041 [1]	Hampden County, MA	289 [0.67]	12H	2054	0.43	0.11	0	4.85
Berlin 5 Fuel: Diesel Oil	3734 [A]	Washington County, VT	41.8 [0.89]	10M	2027	0.79	0.12	0.01	13.22
Berlin 5 Fuel: Diesel Oil	3734 [B]	Washington County, VT	41.8 [0.89]	10M	2027	0.79	0.12	0.01	13.22
Blackstone Power Generation LLC Fuel: Pipeline Natural Gas	55212 [1]	Worcester County, MA	289 [0.44]	12H	2056	0.64	0.1	0.01	4.78
Blackstone Power Generation LLC Fuel: Pipeline Natural Gas	55212 [2]	Worcester County, MA	289 [0.45]	12H	2056	0.65	0.09	0.01	4.89

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Branford Fuel: Other Oil	540 [10]	New Haven County, CT	21.8 [0.53]	10M	2024	0.78	14.91	0.01	7
Bridgeport Energy Fuel: Pipeline Natural Gas	55042 [BE1]	Fairfield County, CT	350 [0.62]	12H	2053	0.44	0.13	0	4.55
Bridgeport Energy Fuel: Pipeline Natural Gas	55042 [BE2]	Fairfield County, CT	350 [0.64]	12H	2053	0.43	0.13	0	4.57
Bridgeport Harbor Station Fuel: Pipeline Natural Gas	568 [BHB5]	Fairfield County, CT	575.6 [0.78]	1H	2074	0.38	0.04	0	5.03
Bridgeport Harbor Station Fuel: Residual Oil	568 [BHB2]	Fairfield County, CT	179.5 [0.78]	1H	2016	1.02	1.39	3.35	9.95
Burgess BioPower Fuel: Wood	58054 [ST01]	Coos County, NH	75 [0.94]	OVER	2058	1.52	0.92	0.07	13.69

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Canal Station Fuel: Residual Oil	1599 [2]	Barnstable County, MA	580 [0.35]	12H	2030	0.76	1.49	2.2	3.77
Canal Station Fuel: Pipeline Natural Gas	1599 [3]	Barnstable County, MA	367.7 [0.69]	12H	2030	0.6	0.1	0.01	6.62
Canal Station Fuel: Residual Oil	1599 [1]	Barnstable County, MA	585 [0.53]	12H	2023	0.78	0.98	3.51	5.07
Cleary Flood Fuel: Residual Oil	1682 [8]	Bristol County, MA	28 [0.61]	10M	2021	1.19	3.87	10.45	9.01
Cleary Flood Fuel: Pipeline Natural Gas	1682 [9]	Bristol County, MA	118 [0.49]	10M	2030	0.63	1.6	0.07	5.15
Cos Cob Fuel: Other Oil	542 [10]	Fairfield County, CT	25 [0.56]	10M	2024	0.78	13.5	0.01	6.27
Cos Cob Fuel: Other Oil	542 [11]	Fairfield County, CT	25 [0.58]	10M	2024	0.78	13.36	0.01	6.51
Cos Cob Fuel: Other Oil	542 [12]	Fairfield County, CT	25 [0.58]	10M	2024	0.78	13.7	0.01	6.58

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Cos Cob Fuel: Other Oil	542 [14]	Fairfield County, CT	20 [0.72]	10M	2030	0.78	16.34	0.01	10.33
Cos Cob Fuel: Other Oil	542 [13]	Fairfield County, CT	20 [0.68]	10M	2030	0.78	18.2	0.01	10.38
CPV Towantic Energy Center Fuel: Pipeline Natural Gas	56047 [2]	New Haven County, CT	565.5 [0.62]	12H	2073	0.39	0.04	0	4.1
CPV Towantic Energy Center Fuel: Pipeline Natural Gas	56047 [1]	New Haven County, CT	565.5 [0.63]	12H	2073	0.38	0.04	0	4.1
Dartmouth Power Fuel: Pipeline Natural Gas	52026 [2]	Bristol County, MA	24.7 [0.7]	12H	2064	0.63	0.13	0.01	7.4
Dartmouth Power Fuel: Pipeline Natural Gas	52026 [1]	Bristol County, MA	77 [0.63]	12H	2047	0.48	0.26	0.01	5.06
Devon Fuel: Other Oil	544 [10]	New Haven County, CT	18.6 [0.67]	1H	2040	0.78	13.74	0.01	7.67

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Devon Fuel: Pipeline Natural Gas	544 [14]	New Haven County, CT	43 [0.55]	1H	2051	0.79	8.21	0.18	5.98
Devon Fuel: Pipeline Natural Gas	544 [13]	New Haven County, CT	43 [0.56]	1H	2051	0.8	8.41	0.21	6.03
Devon Fuel: Pipeline Natural Gas	544 [12]	New Haven County, CT	43 [0.56]	1H	2051	0.78	8.27	0.19	6.07
Devon Fuel: Pipeline Natural Gas	544 [11]	New Haven County, CT	43 [0.56]	1H	2051	0.79	8.66	0.2	6.1
Devon Fuel: Diesel Oil	544 [16]	New Haven County, CT	51 [0.72]	1H	2065	0.58	0.11	0.01	5.17
Devon Fuel: Diesel Oil	544 [15]	New Haven County, CT	51 [0.72]	1H	2065	0.58	0.12	0.01	5.22
Devon Fuel: Diesel Oil	544 [18]	New Haven County, CT	51 [0.74]	1H	2065	0.58	0.13	0.01	5.44
Devon Fuel: Diesel Oil	544 [17]	New Haven County, CT	51 [0.75]	1H	2065	0.59	0.11	0.01	5.53

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Dighton Fuel: Pipeline Natural Gas	55026 [1]	Bristol County, MA	200 [0.74]	12H	2054	0.46	0.1	0	5.72
Exelon West Medway II Fuel: Pipeline Natural Gas	59882 [J5]	Norfolk County, MA	131.8 [0.39]	10M	2074	0.55	0.09	0.01	3.62
Exelon West Medway II Fuel: Pipeline Natural Gas	59882 [J4]	Norfolk County, MA	131.8 [0.4]	10M	2074	0.55	0.09	0.01	3.69
Fore River Energy Center Fuel: Pipeline Natural Gas	55317 [11]	Norfolk County, MA	593.6 [0.53]	OVER	2058	0.42	0.05	0	3.74
Fore River Energy Center Fuel: Pipeline Natural Gas	55317 [12]	Norfolk County, MA	593.6 [0.55]	OVER	2058	0.44	0.05	0	4.01
Framingham Station Fuel: Diesel Oil	1586 [FJ-3]	Middlesex County, MA	14.2 [0.41]	10M	2024	0.78	11.86	0.01	8.46

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Framingham Station Fuel: Diesel Oil	1586 [FJ-2]	Middlesex County, MA	14.2 [0.4]	10M	2024	0.78	11.18	0.01	8.74
Framingham Station Fuel: Diesel Oil	1586 [FJ-1]	Middlesex County, MA	14.2 [0.43]	10M	2024	0.78	11.44	0.01	8.87
Franklin Drive Fuel: Other Oil	561 [10]	Litchfield County, CT	21.8 [0.47]	10M	2024	0.78	18.45	0.01	7.26
Granite Ridge Energy Fuel: Pipeline Natural Gas	55170 [1]	Rockingham County, NH	530 [0.36]	12H	2058	0.64	0.1	0.01	3.9
Granite Ridge Energy Fuel: Pipeline Natural Gas	55170 [2]	Rockingham County, NH	530 [0.36]	12H	2058	0.64	0.1	0.01	3.91
J C McNeil Fuel: Wood	589 [1]	Chittenden County, VT	59.5 [0.82]	OVER	2029	1.48	0.98	0.01	11.55
Kendall Green Energy LLC Fuel: Diesel Oil	1595 [S6]	Middlesex County, MA	20 [0.44]	12H	2025	0.78	23.04	0.01	9.98

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Kendall Green Energy LLC Fuel: Pipeline Natural Gas	1595 [4]	Middlesex County, MA	253.6 [1.03]	12H	2030	0.39	0.05	0	6.65
Kendall Green Energy LLC Fuel: Pipeline Natural Gas	1595 [3]	Middlesex County, MA	54.4 [0.82]	12H	2009	1.47	1.28	8.28	13.57
Kendall Green Energy LLC Fuel: Pipeline Natural Gas	1595 [2]	Middlesex County, MA	50.2 [0.87]	12H	2004	1.54	1	0.01	14.75
Kleen Energy Systems Project Fuel: Pipeline Natural Gas	56798 [U1]	Middlesex County, CT	494 [0.55]	12H	2066	0.41	0.05	0	3.79
Kleen Energy Systems Project Fuel: Pipeline Natural Gas	56798 [U2]	Middlesex County, CT	494 [0.55]	12H	2066	0.41	0.05	0	3.8

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MW h	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MW h
Lake Road Generating Company Fuel: Pipeline Natural Gas	55149 [LRG3]	Windham County, CT	280 [0.52]	12H	2056	0.66	0.07	0.01	5.75
Lake Road Generating Company Fuel: Pipeline Natural Gas	55149 [LRG1]	Windham County, CT	280 [0.51]	12H	2056	0.67	0.08	0.01	5.76
Lake Road Generating Company Fuel: Pipeline Natural Gas	55149 [LRG2]	Windham County, CT	280 [0.52]	12H	2056	0.66	0.08	0.01	5.84
Lost Nation Fuel: Diesel Oil	2362 [CT1]	Coos County, NH	18 [0.42]	10M	2024	0.78	21.48	0.01	14.44
Maine Independence Station Fuel: Pipeline Natural Gas	55068 [2]	Penobscot County, ME	371.2 [0.28]	12H	2055	0.7	0.21	0.01	3.33

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Maine Independence Station Fuel: Pipeline Natural Gas	55068 [1]	Penobscot County, ME	371.2 [0.29]	12H	2055	0.7	0.2	0.01	3.34
Manchester Street Station Fuel: Pipeline Natural Gas	3236 [9]	Providence County, RI	171 [0.5]	12H	2050	0.72	0.41	0.01	5.97
Manchester Street Station Fuel: Pipeline Natural Gas	3236 [10]	Providence County, RI	173 [0.51]	12H	2050	0.7	0.35	0.01	6.03
Manchester Street Station Fuel: Pipeline Natural Gas	3236 [11]	Providence County, RI	171 [0.52]	12H	2050	0.71	0.37	0.01	6.16
MBTA South Boston Power Facility Fuel: Other Oil	10176 [B]	Suffolk County, MA	69 [0.4]	10M	2030	0.72	1.41	0.01	3.61
MBTA South Boston Power Facility Fuel: Other Oil	10176 [A]	Suffolk County, MA	69 [0.41]	10M	2030	0.71	1.36	0.01	3.61

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MW h	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MW h
Medway Station Fuel: Diesel Oil	1592 [J1T1]	Norfolk County, MA	45 [0.24]	1H	2025	1.69	11.23	0.01	4.95
Medway Station Fuel: Diesel Oil	1592 [J1T2]	Norfolk County, MA	45 [0.26]	1H	2025	1.55	10.72	0.01	4.98
Medway Station Fuel: Diesel Oil	1592 [J2T1]	Norfolk County, MA	45 [0.26]	1H	2025	1.6	9.44	0.01	5.04
Medway Station Fuel: Diesel Oil	1592 [J2T2]	Norfolk County, MA	45 [0.25]	1H	2025	1.63	10.37	0.01	5.04
Medway Station Fuel: Diesel Oil	1592 [J3T2]	Norfolk County, MA	45 [0.28]	1H	2025	1.54	9.75	0.01	5.37
Medway Station Fuel: Diesel Oil	1592 [J3T1]	Norfolk County, MA	45 [0.28]	1H	2025	1.57	10.55	0.01	5.42
Merrimack Fuel: Other Oil	2364 [CT2]	Merrimack County, NH	18.6 [0.42]	OVER	2024	0.78	24.04	0.01	12.81
Merrimack Fuel: Other Oil	2364 [CT1]	Merrimack County, NH	18.6 [0.43]	OVER	2024	0.78	23.18	0.01	12.88
Merrimack Fuel: Coal	2364 [1]	Merrimack County, NH	113.6 [0.87]	OVER	2030	1.02	2.77	1.32	8.67

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MW h	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MW h
Merrimack Fuel: Coal	2364 [2]	Merrimack County, NH	345.6 [0.77]	OVER	2030	1.01	2.57	1.53	7.62
Middletown Fuel: Other Oil	562 [10]	Middlesex County, CT	18.6 [0.49]	10M	2021	0.78	17.23	0.01	7.87
Middletown Fuel: Diesel Oil	562 [14]	Middlesex County, CT	60.5 [0.58]	10M	2030	0.58	0.05	0.01	4.23
Middletown Fuel: Diesel Oil	562 [15]	Middlesex County, CT	60.5 [0.58]	10M	2030	0.6	0.06	0.01	4.36
Middletown Fuel: Diesel Oil	562 [12]	Middlesex County, CT	60.5 [0.59]	10M	2030	0.59	0.07	0.01	4.43
Middletown Fuel: Diesel Oil	562 [13]	Middlesex County, CT	60.5 [0.59]	10M	2030	0.59	0.06	0.01	4.44
Middletown Fuel: Pipeline Natural Gas	562 [2]	Middlesex County, CT	113.6 [0.58]	10M	2013	0.68	1.21	0.54	6.36
Middletown Fuel: Pipeline Natural Gas	562 [3]	Middlesex County, CT	239.4 [0.53]	10M	2019	0.62	2	0.3	5.36

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Middletown Fuel: Residual Oil	562 [4]	Middlesex County, CT	414.9 [0.39]	10M	2028	1.11	3.15	3.64	5.33
Milford Power Company LLC Fuel: Pipeline Natural Gas	55126 [CT02]	New Haven County, CT	289 [0.81]	12H	2057	0.42	0.05	0	5.7
Milford Power Company LLC Fuel: Pipeline Natural Gas	55126 [CT01]	New Haven County, CT	289 [0.83]	12H	2057	0.42	0.05	0	5.85
Milford Power, LLC Fuel: Pipeline Natural Gas	54805 [1]	Worcester County, MA	249.3 [0.45]	1H	2048	0.59	0.3	0.01	4.44
Millennium Power Fuel: Pipeline Natural Gas	55079 [1]	Worcester County, MA	360 [0.55]	12H	2055	0.64	0.14	0.01	5.87
Montville Fuel: Residual Oil	546 [5]	New London County, CT	80.4 [0.59]	10M	2009	0.82	1.46	1.92	6.74

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Montville Fuel: Residual Oil	546 [6]	New London County, CT	414.9 [0.33]	10M	2026	1.05	2.57	3.53	4.24
Mystic Fuel: Pipeline Natural Gas	1588 [94]	Middlesex County, MA	593.6 [0.49]	12H	2024	0.43	0.05	0	3.51
Mystic Fuel: Pipeline Natural Gas	1588 [93]	Middlesex County, MA	593.6 [0.49]	12H	2024	0.43	0.06	0	3.53
Mystic Fuel: Pipeline Natural Gas	1588 [82]	Middlesex County, MA	593.6 [0.51]	12H	2024	0.42	0.06	0	3.62
Mystic Fuel: Pipeline Natural Gas	1588 [81]	Middlesex County, MA	593.6 [0.51]	12H	2024	0.42	0.05	0	3.65
New Haven Harbor Fuel: Diesel Oil	6156 [NHHS2]	New Haven County, CT	60.5 [0.59]	OVER	2030	0.58	0.19	0.01	4.36
New Haven Harbor Fuel: Diesel Oil	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	CO ₂ short tons/MW h	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MW h
New Haven Harbor Fuel: Diesel Oil	6156 [NHHS4]	New Haven County, CT	60.5 [0.6]	OVER	2030	0.58	0.15	0.01	4.4
New Haven Harbor Fuel: Residual Oil	6156 [NHB1]	New Haven County, CT	460 [0.35]	OVER	2030	0.78	1.19	1.89	3.7
Newington Fuel: Residual Oil	8002 [1]	Rockingham County, NH	414 [0.35]	OVER	2029	0.95	2.33	4.08	4.54
Newington Energy Fuel: Pipeline Natural Gas	55661 [2]	Rockingham County, NH	419.9 [0.48]	12H	2057	0.44	0.1	0.01	3.48
Newington Energy Fuel: Pipeline Natural Gas	55661 [1]	Rockingham County, NH	419.9 [0.5]	12H	2057	0.45	0.1	0.01	3.62
Ocean State Power Fuel: Pipeline Natural Gas	51030 [2]	Providence County, RI	171.4 [0.41]	12H	2045	0.73	0.34	0.01	5.05

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Ocean State Power Fuel: Pipeline Natural Gas	51030 [1]	Providence County, RI	171.4 [0.43]	12H	2045	0.71	0.31	0.01	5.06
Ocean State Power II Fuel: Pipeline Natural Gas	54324 [3]	Providence County, RI	171.4 [0.4]	12H	2046	0.76	0.35	0.01	5.14
Ocean State Power II Fuel: Pipeline Natural Gas	54324 [4]	Providence County, RI	171.4 [0.42]	12H	2046	0.75	0.37	0.01	5.23
Penny Lane Gas Turbine Fuel: Diesel Oil	3754 [CT1]	Chittenden County, VT	25.5 [0.92]	1H	2026	0.78	0.1	0.01	13.17
Penny Lane Gas Turbine Fuel: Diesel Oil	3754 [CT2]	Chittenden County, VT	25.5 [0.92]	1H	2026	0.78	0.1	0.01	13.17
Pittsfield Generating Fuel: Pipeline Natural Gas	50002 [1]	Berkshire County, MA	93.4 [0.34]	12H	2045	0.71	0.28	0	3.94

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Pittsfield Generating Fuel: Pipeline Natural Gas	50002 [3]	Berkshire County, MA	93.4 [0.35]	12H	2045	0.71	0.25	0	4.07
Pittsfield Generating Fuel: Pipeline Natural Gas	50002 [2]	Berkshire County, MA	93.4 [0.35]	12H	2045	0.72	0.27	0	4.08
Potter Fuel: Pipeline Natural Gas	1660 [4]	Norfolk County, MA	58 [0.67]	12H	2024	0.53	0.11	0.01	5.6
Potter Fuel: Pipeline Natural Gas	1660 [5]	Norfolk County, MA	58 [0.67]	12H	2024	0.53	0.14	0.01	5.62
Potter Fuel: Pipeline Natural Gas	1660 [3]	Norfolk County, MA	101 [0.44]	12H	2024	0.74	4.75	0	5.5
Rhode Island State Energy Center Fuel: Pipeline Natural Gas	55107 [RISEP2]	Providence County, RI	400 [0.62]	12H	2057	0.4	0.05	0	4.18

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Rhode Island State Energy Center Fuel: Pipeline Natural Gas	55107 [RISEP1]	Providence County, RI	400 [0.62]	12H	2057	0.4	0.05	0	4.21
Rumford Power Fuel: Pipeline Natural Gas	55100 [1]	Oxford County, ME	272.9 [0.64]	12H	2055	0.43	0.16	0	4.7
Ryegate Associates Fuel: Wood	51026 [1]	Caledonia County, VT	20 [0.95]		2037	1.48	0.55	0.01	14.24
Salem Harbor Station NGCC Fuel: Pipeline Natural Gas	60903 [2]	Essex County, MA	399.1 [0.56]	12H	2073	0.41	0.07	0	3.93
Salem Harbor Station NGCC Fuel: Pipeline Natural Gas	60903 [1]	Essex County, MA	399.1 [0.56]	12H	2072	0.42	0.06	0	3.97
Schiller Fuel: Other Oil	2367 [CT1]	Rockingham County, NH	21.3 [0.4]	12H	2024	0.78	25.56	0.01	13.27
Schiller Fuel: Coal	2367 [6]	Rockingham County, NH	50 [0.55]	12H	2030	1.23	2.82	9.97	6.7

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Schiller Fuel: Coal	2367 [4]	Rockingham County, NH	50 [0.54]	12H	2027	1.26	3.14	10.77	6.76
Schiller Fuel: Wood	2367 [5]	Rockingham County, NH	50 [0.87]	12H	2000	1.54	1	0.01	12.79
Stony Brook Energy Center Fuel: Diesel Oil	6081 [4]	Hampden County, MA	85 [0.48]	10M	2030	1.07	15.82	0.01	6.39
Stony Brook Energy Center Fuel: Diesel Oil	6081 [5]	Hampden County, MA	85 [0.48]	10M	2030	1.1	16.24	0.01	6.55
Stony Brook Energy Center Fuel: Pipeline Natural Gas	6081 [2]	Hampden County, MA	190 [0.32]	10M	2030	0.85	1.89	0	3.69
Stony Brook Energy Center Fuel: Pipeline Natural Gas	6081 [3]	Hampden County, MA	190 [0.33]	10M	2030	0.77	1.9	0	3.92
Stony Brook Energy Center Fuel: Pipeline Natural Gas	6081 [1]	Hampden County, MA	190 [0.34]	10M	2030	0.77	2.02	0	3.97

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Tiverton Power, LLC Fuel: Pipeline Natural Gas	55048 [1]	Newport County, RI	272.5 [0.83]	12H	2055	0.42	0.08	0	5.82
Torrington Terminal Fuel: Other Oil	565 [10]	Litchfield County, CT	21.8 [0.5]	10M	2024	0.78	17.23	0.01	7.23
Wallingford Energy, LLC Fuel: Pipeline Natural Gas	55517 [CT01]	New Haven County, CT	50 [0.74]	1H	2056	0.47	0.08	0	5.82
Wallingford Energy, LLC Fuel: Pipeline Natural Gas	55517 [CT07]	New Haven County, CT	50 [0.69]	1H	2072	0.5	0.1	0.01	5.83
Wallingford Energy, LLC Fuel: Pipeline Natural Gas	55517 [CT02]	New Haven County, CT	50 [0.73]	1H	2056	0.48	0.09	0	5.86
Wallingford Energy, LLC Fuel: Pipeline Natural Gas	55517 [CT03]	New Haven County, CT	50 [0.7]	1H	2056	0.5	0.09	0.01	5.86

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Wallingford Energy, LLC Fuel: Pipeline Natural Gas	55517 [CT05]	New Haven County, CT	50 [0.73]	1H	2056	0.48	0.08	0	5.86
Wallingford Energy, LLC Fuel: Pipeline Natural Gas	55517 [CT06]	New Haven County, CT	50 [0.7]	1H	2072	0.51	0.1	0.01	5.97
Wallingford Energy, LLC Fuel: Pipeline Natural Gas	55517 [CT04]	New Haven County, CT	50 [0.74]	1H	2056	0.48	0.08	0.01	5.98
Waterbury Generation Fuel: Pipeline Natural Gas	56629 [10]	New Haven County, CT	96 [0.69]	1H	2064	0.47	0.14	0.02	5.47
Waters River Fuel: Pipeline Natural Gas	1678 [1]	Essex County, MA	21.3 [0.68]	1H	2026	0.78	5.47	0.01	7.97
Waters River Fuel: Pipeline Natural Gas	1678 [2]	Essex County, MA	49.9 [0.49]	1H	2026	0.75	3.39	0.01	5.64

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
Waterside Power, LLC Fuel: Diesel Oil	56189 [4]	Fairfield County, CT	23.2 [0.92]	1H	2059	0.78	0.1	0.01	13.17
Waterside Power, LLC Fuel: Diesel Oil	56189 [5]	Fairfield County, CT	23.2 [0.92]	1H	2059	0.78	0.1	0.01	13.17
Waterside Power, LLC Fuel: Diesel Oil	56189 [7]	Fairfield County, CT	23.2 [0.92]	1H	2061	0.78	0.1	0.01	13.17
Westbrook Energy Center Fuel: Pipeline Natural Gas	55294 [2]	Cumberland County, ME	379.7 [0.59]	12H	2056	0.38	0.1	0	3.76
Westbrook Energy Center Fuel: Pipeline Natural Gas	55294 [1]	Cumberland County, ME	379.7 [0.59]	12H	2056	0.38	0.1	0	3.78
White Lake Fuel: Other Oil	2369 [CT1]	Carroll County, NH	18.6 [0.42]	10M	2024	0.78	23.01	0.01	12.95
William F Wyman Fuel: Residual Oil	1507 [2]	Cumberland County, ME	50 [0.17]	OVER	2013	1.35	3.97	10.65	2.62

Facility name	Facility [unit] ID	Location	Nameplate capacity (MW) [capacity factor]	Ramp	Retirement year	CO ₂ short tons/MWh	NO _x lb/MWh	SO ₂ lb/MWh	Heat input mmBtu/MWh
William F Wyman Fuel: Residual Oil	1507 [1]	Cumberland County, ME	50 [0.24]	OVER	2012	1.22	3.45	9.63	3.34
William F Wyman Fuel: Residual Oil	1507 [3]	Cumberland County, ME	213.6 [0.18]	OVER	2020	0.9	1.6	7.09	1.92
William F Wyman Fuel: Residual Oil	1507 [4]	Cumberland County, ME	649.1 [0.35]	OVER	2030	0.87	1.75	6.52	3.54

Table S5: Inputs to the generation model and their probabilistic treatment. Fixed inputs are exogenous assumptions.

Description	Probabilistic treatment	Calculation method or source	Location in SI
Hourly electricity demand through 2050	Exogenous; fixed	Data provided by ISO-NE (Commonwealth of Massachusetts, 2020).	SI 2.2
Hourly nuclear, hydropower and biomass capacity factors	Exogenous; fixed	Data provided by ISO-NE (Commonwealth of Massachusetts, 2020).	SI 2.4.2
Solar PV, onshore wind and offshore wind capacity factors	Exogenous; sampled. Separate technology profile indices; interpolated labels 1–99	ISO-NE stochastic annual-percentile profiles (ISO-NE, 2024a); linear interpolation between supplied labels and technology-specific selection by calendar day and hour.	SI 2.4.1
Energy storage operating constraints	Exogenous; fixed	Data provided by ISO-NE (Commonwealth of Massachusetts, 2020).	SI 2.5
Hourly electricity imports from other jurisdictions	Exogenous; sampled. Empirical distributions (1st to 99th percentiles)	Empirical distributions for percentiles ranging from 1 to 99 were simulated using historical data (ISO-NE, 2024b).	SI 2.6
Fossil fuel facility data (e.g., nameplate capacity, stack heights, age and planned retirements)	Exogenous; fixed	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).	SI 2.7
Fossil fuel hourly generation data	Exogenous; sampled. 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.	SI 2.7.3
	Exogenous; fixed	Where historical data were unavailable, data were pooled from comparable facility types within the U.S. EPA CAMPD.	SI 2.7.3
Fossil fuel hourly emissions data (CO₂, SO₂ and NO_x)	Exogenous; fixed	CAMPD 2013–2023; unit mean/load/load-ramp structures selected using validation; see Sections 2.7.3 and 2.13.	SI 2.7.3, 2.13

Description	Probabilistic treatment	Calculation method or source	Location in SI
	Exogenous; fixed	Where historical data were unavailable, data were pooled from comparable facility types within the U.S. EPA CAMPD.	SI 2.7.3, 2.13

Table S6: Inputs to the cost calculations and their probabilistic treatment. Charts show the normalized uniform draw U between 0 and 1, used to interpolate between each coefficient's specified caps. Draws are shared across pathways and years for the same simulation and cost coefficient. Fixed inputs have no distribution chart.

Description	Probabilistic treatment	Calculation method or source	Location in the SI
CAPEX and FOM costs	Shared uniform interpolation between lower and upper cost cases; single-valued caps remain fixed.	Data provided by NREL (2024).	SI 2.8
VOM costs	Shared uniform interpolation between cost cases.	Data provided by NREL (2024).	SI 2.8
Fossil generation fuel costs	Fixed fuel/year coefficients; totals vary with generation.	Data provided by NREL (2021).	SI 2.8
Non-fossil generation fuel costs	Shared uniform interpolation between retained cases.	Data provided by NREL (2024).	SI 2.8
Electricity purchases and intertie costs	Shared uniform interpolation between retained price and cost caps.	Imports from Canada provided by Calder et al., (2022) and imports from NYISO provided by DeSantis et al., (2021).	SI 2.10
GHG economic cost	Fixed year-specific social-cost schedules within each discount case.	U.S. EPA (2023).	SI 2.12
GHG emission factors	Fixed fuel-specific coefficients.	Data provided by U.S. EPA GHGRP (2024) to identify the CO _{2eq} of CH ₄ and N ₂ O emissions for different fuel type.	SI 2.7, 2.12

Description	Probabilistic treatment	Calculation method or source	Location in the SI
Air-pollution economic cost	Fixed source-specific coefficients; totals vary with emissions.	AP4; pollutant-specific exceptions described in SI Section 2.13 and Table S8.	SI 2.13
CO economic cost	Fixed published reference coefficient.	Data provided by Calder et al., (2022).	SI 2.13
CO, total particulate and VOC emission factors	Fixed fuel/technology-specific factors.	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 2.7, 2.13
Unmet demand penalty	Fixed \$3,500/MWh.	Fixed ISO-NE penalty; Figure S2 provides the value-of-lost-load curve for context (Potomac Economics, 2024).	SI 2.14
Canadian hydro costs and reservoir methane	Shared uniform interpolation between retained coefficient caps; prescribed capacity allocation.	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 2.11
CPI factors and discount rates	Fixed conversion factors; separate 1.5%, 2% and 2.5% cases.	Data provided by U.S. Bureau of Labor Statistics (2024) API.	SI 2.17

Table S7: Summary of fuel-specific emission factors, including non-biogenic CO₂-eq for CH₄ and N₂O emissions, PM rates and ratios, and estimated CO and VOC emissions.

Fuel category	non-biogenic CH ₄ -to-CO ₂ (ratio %)	non-biogenic N ₂ O-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 marginal air-pollution damage coefficients. The pollutant sources and particulate-mass calculation are described in Section 2.13. Pollutant's damage coefficients are expressed in 2024 USD per metric tonne and assigned by source county. Units without represented generation do not contribute to calculated damages.

Unit ID	FIPS	AP4 Model Match	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
10176_A	25025	EGU	10,975	65,992	110,681	9,606	2,427	1,688
10176_B	25025	EGU	10,975	65,992	110,681	9,606	2,427	1,688
10307_1	25021	EGU	10,547	62,890	85,048	7,430	2,084	1,653
10307_2	25021	EGU	10,547	62,890	85,048	7,430	2,084	1,653
1507_4	23005	EGU	7,165	37,569	38,505	3,355	210	422
1592_J1T1	25021	EGU	13,639	85,937	138,036	11,995	2,084	1,653
1592_J1T2	25021	EGU	13,639	85,937	138,036	11,995	2,084	1,653
1592_J2T1	25021	EGU	13,639	85,937	138,036	11,995	2,084	1,653
1592_J2T2	25021	EGU	13,639	85,937	138,036	11,995	2,084	1,653
1592_J3T1	25021	EGU	13,639	85,937	138,036	11,995	2,084	1,653
1592_J3T2	25021	EGU	13,639	85,937	138,036	11,995	2,084	1,653
1595_4	25017	EGU	13,061	69,979	90,251	7,856	2,718	2,401
1595_S6	25017	EGU	13,061	69,979	90,251	7,856	2,718	2,401
1599_2	25001	EGU	7,036	40,989	31,838	2,810	212	466
1599_3	25001	EGU	7,036	40,989	31,838	2,810	212	466

Unit ID	FIPS	AP4 Model Match	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
1678_1	25009	EGU	9,515	59,569	92,412	8,004	1,184	1,056
1678_2	25009	EGU	9,515	59,569	92,412	8,004	1,184	1,056
1682_9	25005	EGU	13,875	117,205	121,318	10,510	1,346	1,354
2364_1	33013	EGU	20,635	109,982	76,581	6,787	414	675
2364_2	33013	EGU	20,635	109,982	76,581	6,787	414	675
2367_4	33015	county_nonEGU_proxy	16,935	76,029	105,324	9,232	1,209	1,278
2367_6	33015	county_nonEGU_proxy	16,935	76,029	105,324	9,232	1,209	1,278
3236_10	44007	EGU	21,285	150,241	263,971	22,749	1,642	1,428
3236_11	44007	EGU	21,285	150,241	263,971	22,749	1,642	1,428
3236_9	44007	EGU	21,285	150,241	263,971	22,749	1,642	1,428
50002_1	25003	EGU	26,538	177,182	173,344	15,897	777	997
50002_2	25003	EGU	26,538	177,182	173,344	15,897	777	997
50002_3	25003	EGU	26,538	177,182	173,344	15,897	777	997
51030_1	44007	EGU	22,366	157,661	205,267	17,814	1,642	1,428
51030_2	44007	EGU	22,366	157,661	205,267	17,814	1,642	1,428
52026_1	25005	EGU	14,128	89,070	118,485	10,262	1,346	1,354
52026_2	25005	EGU	14,128	89,070	118,485	10,262	1,346	1,354
542_13	9001	EGU	21,179	139,470	183,948	17,105	2,298	2,096

Unit ID	FIPS	AP4 Model Match	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
542_14	9001	EGU	21,179	139,470	183,948	17,105	2,298	2,096
54324_3	44007	county_nonEGU_proxy	14,056	65,896	192,570	16,661	1,642	1,428
54324_4	44007	county_nonEGU_proxy	14,056	65,896	192,570	16,661	1,642	1,428
544_10	9009	EGU	18,451	109,571	116,765	10,493	563	755
544_11	9009	EGU	18,451	109,571	116,765	10,493	563	755
544_12	9009	EGU	18,451	109,571	116,765	10,493	563	755
544_13	9009	EGU	18,451	109,571	116,765	10,493	563	755
544_14	9009	EGU	18,451	109,571	116,765	10,493	563	755
544_15	9009	EGU	18,451	109,571	116,765	10,493	563	755
544_16	9009	EGU	18,451	109,571	116,765	10,493	563	755
544_17	9009	EGU	18,451	109,571	116,765	10,493	563	755
544_18	9009	EGU	18,451	109,571	116,765	10,493	563	755
546_6	9011	EGU	10,147	58,068	45,156	3,975	1,253	1,485
54805_1	25027	EGU	13,777	82,290	122,339	10,580	2,135	2,098
55026_1	25005	EGU	14,415	95,052	124,713	10,795	1,346	1,354
55041_1	25013	EGU	15,813	103,965	142,495	12,580	1,071	1,048
55042_BE1	9001	EGU	22,875	155,001	193,316	17,748	2,298	2,096
55042_BE2	9001	EGU	22,875	155,001	193,316	17,748	2,298	2,096

Unit ID	FIPS	AP4 Model Match	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
55048_1	44005	EGU	17,147	121,915	159,413	13,769	981	1,014
55068_1	23019	EGU	7,854	38,462	36,557	3,156	71	172
55068_2	23019	EGU	7,854	38,462	36,557	3,156	71	172
55079_1	25027	EGU	11,652	66,788	87,595	7,600	2,135	2,098
55100_1	23017	EGU	11,700	68,166	47,658	4,147	210	441
55107_RISEP1	44007	EGU	37,196	284,565	531,891	45,691	1,642	1,428
55107_RISEP2	44007	EGU	37,196	284,565	531,891	45,691	1,642	1,428
55126_CT01	9009	EGU	21,140	139,743	160,725	14,519	1,378	1,406
55126_CT02	9009	EGU	21,140	139,743	160,725	14,519	1,378	1,406
55149_LRG1	9015	EGU	20,103	137,343	149,810	13,103	1,069	1,318
55149_LRG2	9015	EGU	20,103	137,343	149,810	13,103	1,069	1,318
55149_LRG3	9015	EGU	20,103	137,343	149,810	13,103	1,069	1,318
55170_0001	33015	EGU	20,542	118,758	120,427	10,537	1,209	1,278
55170_0002	33015	EGU	20,542	118,758	120,427	10,537	1,209	1,278
55211_1	25021	EGU	12,243	75,303	112,160	9,769	2,084	1,653
55211_2	25021	EGU	12,243	75,303	112,160	9,769	2,084	1,653
55212_1	25027	EGU	12,923	74,702	108,894	9,427	2,135	2,098
55212_2	25027	EGU	12,923	74,702	108,894	9,427	2,135	2,098

Unit ID	FIPS	AP4 Model Match	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
55294_1	23005	EGU	9,910	58,340	65,448	5,660	444	659
55294_2	23005	EGU	9,910	58,340	65,448	5,660	444	659
55317_11	25021	EGU	9,533	55,315	62,611	5,482	811	914
55317_12	25021	EGU	9,533	55,315	62,611	5,482	811	914
55517_CT01	9009	EGU	19,298	126,936	146,356	13,020	1,378	1,406
55517_CT02	9009	EGU	19,298	126,936	146,356	13,020	1,378	1,406
55517_CT03	9009	EGU	19,298	126,936	146,356	13,020	1,378	1,406
55517_CT04	9009	EGU	19,298	126,936	146,356	13,020	1,378	1,406
55517_CT05	9009	EGU	19,298	126,936	146,356	13,020	1,378	1,406
55517_CT06	9009	EGU	19,298	126,936	146,356	13,020	1,378	1,406
55517_CT07	9009	EGU	19,298	126,936	146,356	13,020	1,378	1,406
55661_1	33015	EGU	16,792	94,661	79,467	6,968	1,209	1,278
55661_2	33015	EGU	16,792	94,661	79,467	6,968	1,209	1,278
56047_1	9009	county_nonEGU_proxy	17,944	87,991	181,081	16,142	1,378	1,406
56047_2	9009	county_nonEGU_proxy	17,944	87,991	181,081	16,142	1,378	1,406
562_12	9007	EGU	10,444	50,838	48,952	4,290	375	557
562_13	9007	EGU	10,444	50,838	48,952	4,290	375	557
562_14	9007	EGU	10,444	50,838	48,952	4,290	375	557

Unit ID	FIPS	AP4 Model Match	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
562_15	9007	EGU	10,444	50,838	48,952	4,290	375	557
562_4	9007	EGU	10,444	50,838	48,952	4,290	375	557
56629_10	9009	EGU	17,821	113,804	136,479	12,165	1,378	1,406
56798_U1	9007	EGU	12,297	77,174	101,047	8,817	763	863
56798_U2	9007	EGU	12,297	77,174	101,047	8,817	763	863
568_BHB5	9001	EGU	16,361	100,826	99,005	8,974	1,003	1,086
58054_ST01	33007	county_nonEGU_proxy	16,400	64,792	49,071	4,284	202	428
589_1	50007	county_nonEGU_proxy	17,116	67,894	63,455	5,573	311	455
59882_J4	25021	county_nonEGU_proxy	10,342	49,955	114,032	9,909	2,084	1,653
59882_J5	25021	county_nonEGU_proxy	10,342	49,955	114,032	9,909	2,084	1,653
6081_001	25013	EGU	13,411	84,349	111,565	9,831	1,071	1,048
6081_002	25013	EGU	13,411	84,349	111,565	9,831	1,071	1,048
6081_003	25013	EGU	13,411	84,349	111,565	9,831	1,071	1,048
6081_004	25013	EGU	13,411	84,349	111,565	9,831	1,071	1,048
6081_005	25013	EGU	13,411	84,349	111,565	9,831	1,071	1,048
60903_1	25009	EGU	10,450	65,841	87,087	7,560	1,184	1,056
60903_2	25009	EGU	10,450	65,841	87,087	7,560	1,184	1,056
6156_NHB1	9009	EGU	16,062	99,290	130,410	11,605	563	755

Unit ID	FIPS	AP4 Model Match	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
6156_NHHS2	9009	EGU	16,062	99,290	130,410	11,605	563	755
6156_NHHS3	9009	EGU	16,062	99,290	130,410	11,605	563	755
6156_NHHS4	9009	EGU	16,062	99,290	130,410	11,605	563	755
6635_AP-1	9009	EGU	12,558	76,638	76,762	6,797	1,378	1,406
8002_1	33015	EGU	11,439	60,780	43,712	3,864	517	681

Table S8 continued: Reference facilities used to assign damage coefficients to hypothetical new gas plants.

New facility	Reference facility	County, state	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
NGCC3000	56798_U1	Middlesex, CT	12,297	77,174	101,047	8,817	763	863
NGCC3001	3236_9	Providence, RI	21,285	150,241	263,971	22,749	1,642	1,428
NGCC3002	54324_3	Providence, RI	14,056	65,896	192,570	16,661	1,642	1,428
NGCC3003	568_BHB5	Fairfield, CT	16,361	100,826	99,005	8,974	1,003	1,086
NGCC3004	3236_10	Providence, RI	21,285	150,241	263,971	22,749	1,642	1,428
NGCC3005	55048_1	Newport, RI	17,147	121,915	159,413	13,769	981	1,014
NGCC3006	55126_CT01	New Haven, CT	21,140	139,743	160,725	14,519	1,378	1,406
NGCC3007	55149_LRG3	Windham, CT	20,103	137,343	149,810	13,103	1,069	1,318
NGCC3008	56047_1	New Haven, CT	17,944	87,991	181,081	16,142	1,378	1,406
NGCC3009	55042_BE2	Fairfield, CT	22,875	155,001	193,316	17,748	2,298	2,096
NGCC3010	51030_2	Providence, RI	22,366	157,661	205,267	17,814	1,642	1,428

New facility	Reference facility	County, state	NO _x	SO ₂	PM _{2.5}	VOC	PM ₁₀	CO
NGCC3011	55170_0002	Rockingham, NH	20,542	118,758	120,427	10,537	1,209	1,278
NGCC3012	55149_LRG2	Windham, CT	20,103	137,343	149,810	13,103	1,069	1,318
NGCC3013	56047_2	New Haven, CT	17,944	87,991	181,081	16,142	1,378	1,406
NGCC3014	55042_BE1	Fairfield, CT	22,875	155,001	193,316	17,748	2,298	2,096
NGCC3015	51030_1	Providence, RI	22,366	157,661	205,267	17,814	1,642	1,428
NGCC3016	55661_1	Rockingham, NH	16,792	94,661	79,467	6,968	1,209	1,278
NGCC3017	55107_RISEP 1	Providence, RI	37,196	284,565	531,891	45,691	1,642	1,428

Table S9: Methane emissions from Canadian reservoirs and relevant facilities

Total reservoir capacity is 7,892 MW, with a hydroelectric capacity factor of 65%. Sources and calculations are described in SI Section 2.11.

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				480			
	Eastmain-1-A	9.43	602.9	5.69e+09	768	4.07e+06	714.22	0.26
	Sarcelle				150			
Laforge-1 Reservoir	Laforge-1	13	1,288	1.67e+10	878	1.91e+07	3349.24	1.22
Robert-Bourassa Reservoir	Robert-Bourassa	5	2,835	1.42e+10	5,616	2.52e+06	443.28	0.16

Table S10: Mean net present costs and central 90% simulation ranges at 1.5% (billion 2024 USD).

Cost Category	A	B1	B2	B3(1)	B3(2)	C1	C2	C3	D
CAPEX	0.00 [0.00, 0.00]	216.45 [189.35, 243.38]	243.83 [210.94, 275.86]	203.71 [178.87, 228.10]	203.71 [178.87, 228.10]	243.24 [133.85, 347.54]	240.73 [209.57, 270.11]	218.48 [191.63, 243.27]	85.53 [76.90, 94.28]
Fixed O&M	45.41 [42.71, 48.16]	84.24 [78.58, 90.00]	90.29 [84.36, 96.30]	81.44 [75.92, 87.09]	81.44 [75.92, 87.09]	99.48 [84.00, 115.25]	91.75 [85.43, 97.90]	86.28 [80.36, 91.96]	64.13 [59.29, 68.82]
Variable O&M	8.12 [7.78, 8.45]	3.50 [3.16, 3.83]	3.94 [3.59, 4.26]	3.50 [3.15, 3.82]	3.50 [3.15, 3.82]	10.52 [9.66, 11.36]	4.68 [4.32, 5.02]	3.94 [3.58, 4.26]	7.65 [7.30, 7.99]
Fuel	58.69 [58.17, 59.21]	23.55 [22.69, 24.34]	28.15 [27.26, 28.99]	23.38 [22.53, 24.15]	23.38 [22.53, 24.15]	54.67 [52.02, 57.32]	30.32 [29.41, 31.21]	24.53 [23.69, 25.34]	61.39 [60.55, 62.17]
Electricity purchases	20.57 [13.62, 27.51]	54.68 [35.73, 73.52]	19.80 [12.08, 27.65]	71.94 [45.84, 97.49]	0.00 [0.00, 0.00]	12.76 [7.98, 17.50]	19.63 [11.93, 27.44]	54.41 [35.56, 73.13]	53.10 [34.74, 71.34]
GHG damages	439.53 [437.58, 441.54]	140.42 [134.76, 145.93]	177.28 [171.17, 183.33]	138.41 [133.04, 143.69]	138.41 [133.04, 143.69]	140.49 [137.46, 143.21]	161.47 [155.80, 166.98]	127.85 [122.80, 132.83]	403.21 [397.42, 408.37]
Air damages	30.18 [30.04, 30.33]	8.44 [8.21, 8.66]	9.82 [9.59, 10.05]	8.40 [8.19, 8.61]	8.40 [8.19, 8.61]	8.83 [8.72, 8.93]	9.34 [9.14, 9.55]	8.02 [7.82, 8.23]	22.45 [22.14, 22.73]
Unmet demand	504.94 [492.62, 516.97]	6.33 [5.78, 6.92]	14.11 [12.93, 15.40]	5.46 [4.98, 5.94]	5.46 [4.98, 5.94]	6.89 [6.57, 7.24]	8.35 [7.67, 9.07]	3.82 [3.46, 4.18]	3.52 [3.30, 3.76]

Cost Category	A	B1	B2	B3(1)	B3(2)	C1	C2	C3	D
Québec purchase adjustment	n/a	n/a	n/a	n/a	18.12 [10.45, 25.82]	n/a	n/a	n/a	n/a
Canadian variable O&M	n/a	n/a	n/a	n/a	0.37 [0.37, 0.37]	n/a	n/a	n/a	n/a
Canadian CAPEX	n/a	n/a	n/a	n/a	49.57 [31.62, 67.47]	n/a	n/a	n/a	n/a
Canadian fixed O&M	n/a	n/a	n/a	n/a	54.24 [25.65, 83.23]	n/a	n/a	n/a	n/a
Reservoir methane	n/a	n/a	n/a	n/a	2.91 [0.90, 5.01]	n/a	n/a	n/a	n/a
Total	1,107.45 [1,093.05, 1,121.47]	537.61 [502.14, 572.47]	587.21 [551.96, 621.61]	536.24 [497.39, 574.02]	589.50 [545.86, 634.18]	576.89 [464.17, 679.30]	566.27 [534.67, 597.65]	527.33 [493.58, 560.33]	700.99 [679.30, 723.99]

Table S11: Mean net present costs and central 90% simulation ranges at 2% (billion 2024 USD).

Cost Category	A	B1	B2	B3(1)	B3(2)	C1	C2	C3	D
CAPEX	0.00 [0.00, 0.00]	203.01 [177.54, 228.31]	228.50 [197.60, 258.63]	191.10 [167.78, 213.98]	191.10 [167.78, 213.98]	226.05 [124.64, 322.74]	225.76 [196.49, 253.30]	205.20 [179.95, 228.53]	79.96 [71.87, 88.13]
Fixed O&M	42.65 [40.15, 45.21]	78.24 [73.02, 83.55]	83.79 [78.33, 89.33]	75.68 [70.60, 80.88]	75.68 [70.60, 80.88]	91.78 [77.65, 106.14]	85.09 [79.28, 90.75]	80.12 [74.66, 85.35]	59.80 [55.34, 64.13]
Variable O&M	7.61 [7.30, 7.92]	3.33 [3.01, 3.63]	3.74 [3.42, 4.04]	3.33 [3.01, 3.63]	3.33 [3.01, 3.63]	9.75 [8.96, 10.51]	4.42 [4.08, 4.73]	3.73 [3.40, 4.03]	7.16 [6.83, 7.47]
Fuel	54.94 [54.45, 55.42]	22.41 [21.59, 23.15]	26.72 [25.88, 27.52]	22.27 [21.48, 23.00]	22.27 [21.48, 23.00]	51.02 [48.61, 53.43]	28.74 [27.89, 29.57]	23.31 [22.50, 24.06]	57.09 [56.29, 57.82]
Electricity purchases	19.14 [12.68, 25.59]	50.55 [33.05, 67.94]	18.45 [11.26, 25.77]	66.17 [42.27, 89.66]	0.00 [0.00, 0.00]	12.02 [7.53, 16.48]	18.30 [11.12, 25.58]	50.30 [32.89, 67.60]	49.09 [32.13, 65.93]
GHG damages	253.33 [252.20, 254.50]	81.54 [78.26, 84.73]	102.81 [99.26, 106.31]	80.43 [77.31, 83.48]	80.43 [77.31, 83.48]	82.01 [80.24, 83.59]	93.81 [90.52, 97.00]	74.32 [71.40, 77.21]	232.05 [228.69, 235.04]
Air damages	28.33 [28.19, 28.47]	8.17 [7.96, 8.38]	9.47 [9.26, 9.69]	8.14 [7.94, 8.34]	8.14 [7.94, 8.34]	8.63 [8.52, 8.72]	9.05 [8.85, 9.24]	7.79 [7.60, 7.98]	21.22 [20.93, 21.49]
Unmet demand	458.06 [446.84, 469.03]	5.86 [5.35, 6.40]	13.05 [11.95, 14.24]	5.07 [4.62, 5.51]	5.07 [4.62, 5.51]	6.62 [6.31, 6.96]	7.78 [7.15, 8.45]	3.54 [3.20, 3.87]	3.32 [3.11, 3.53]
Québec purchase adjustment	n/a	n/a	n/a	n/a	16.88 [9.74, 24.06]	n/a	n/a	n/a	n/a

Cost Category	A	B1	B2	B3(1)	B3(2)	C1	C2	C3	D
Canadian variable O&M	n/a	n/a	n/a	n/a	0.34 [0.34, 0.34]	n/a	n/a	n/a	n/a
Canadian CAPEX	n/a	n/a	n/a	n/a	48.88 [31.18, 66.54]	n/a	n/a	n/a	n/a
Canadian fixed O&M	n/a	n/a	n/a	n/a	50.39 [23.83, 77.32]	n/a	n/a	n/a	n/a
Reservoir methane	n/a	n/a	n/a	n/a	2.10 [0.65, 3.62]	n/a	n/a	n/a	n/a
Total	864.07 [850.82, 877.08]	453.10 [420.36, 485.63]	486.53 [454.28, 518.20]	452.18 [416.74, 487.19]	504.60 [463.45, 546.86]	487.88 [383.69, 582.57]	472.95 [443.54, 502.33]	448.32 [417.42, 478.94]	509.68 [490.06, 529.84]

Table S12: Mean net present costs and central 90% simulation ranges at 2.5% (billion 2024 USD).

Cost Category	A	B1	B2	B3(1)	B3(2)	C1	C2	C3	D
CAPEX	0.00 [0.00, 0.00]	190.70 [166.71, 214.52]	214.48 [185.41, 242.89]	179.54 [157.63, 201.07]	179.54 [157.63, 201.07]	210.32 [116.20, 300.05]	212.04 [184.50, 237.94]	193.03 [169.24, 215.01]	74.86 [67.30, 82.51]
Fixed O&M	40.13 [37.80, 42.51]	72.79 [67.97, 77.69]	77.88 [72.85, 83.00]	70.44 [65.76, 75.25]	70.44 [65.76, 75.25]	84.80 [71.92, 97.88]	79.05 [73.67, 84.25]	74.52 [69.49, 79.35]	55.86 [51.73, 59.86]
Variable O&M	7.15 [6.85, 7.43]	3.17 [2.87, 3.45]	3.56 [3.26, 3.84]	3.17 [2.87, 3.45]	3.17 [2.87, 3.45]	9.05 [8.33, 9.75]	4.19 [3.87, 4.47]	3.54 [3.23, 3.82]	6.71 [6.40, 7.00]
Fuel	51.51 [51.05, 51.95]	21.35 [20.58, 22.06]	25.41 [24.62, 26.15]	21.25 [20.49, 21.94]	21.25 [20.49, 21.94]	47.70 [45.50, 49.91]	27.27 [26.48, 28.05]	22.18 [21.41, 22.89]	53.17 [52.42, 53.87]
Electricity purchases	17.84 [11.81, 23.87]	46.80 [30.62, 62.88]	17.23 [10.52, 24.06]	60.96 [39.04, 82.56]	0.00 [0.00, 0.00]	11.35 [7.11, 15.55]	17.09 [10.39, 23.88]	46.57 [30.47, 62.57]	45.45 [29.76, 61.02]
GHG damages	152.31 [151.62, 153.02]	49.38 [47.40, 51.31]	62.18 [60.03, 64.30]	48.73 [46.84, 50.58]	48.73 [46.84, 50.58]	49.91 [48.84, 50.87]	56.84 [54.85, 58.76]	45.06 [43.29, 46.80]	139.30 [137.27, 141.11]
Air damages	26.63 [26.50, 26.77]	7.91 [7.71, 8.12]	9.14 [8.94, 9.35]	7.90 [7.70, 8.09]	7.90 [7.70, 8.09]	8.43 [8.33, 8.53]	8.77 [8.58, 8.95]	7.57 [7.38, 7.75]	20.09 [19.82, 20.34]
Unmet demand	415.93 [405.71, 425.94]	5.43 [4.96, 5.93]	12.08 [11.06, 13.18]	4.70 [4.30, 5.12]	4.70 [4.30, 5.12]	6.37 [6.07, 6.69]	7.25 [6.67, 7.87]	3.28 [2.97, 3.59]	3.12 [2.92, 3.33]
Québec purchase adjustment	n/a	n/a	n/a	n/a	15.75 [9.09, 22.44]	n/a	n/a	n/a	n/a

Cost Category	A	B1	B2	B3(1)	B3(2)	C1	C2	C3	D
Canadian variable O&M	n/a	n/a	n/a	n/a	0.31 [0.31, 0.31]	n/a	n/a	n/a	n/a
Canadian CAPEX	n/a	n/a	n/a	n/a	48.21 [30.76, 65.63]	n/a	n/a	n/a	n/a
Canadian fixed O&M	n/a	n/a	n/a	n/a	46.89 [22.17, 71.95]	n/a	n/a	n/a	n/a
Reservoir methane	n/a	n/a	n/a	n/a	1.60 [0.50, 2.75]	n/a	n/a	n/a	n/a
Total	711.49 [699.45, 723.56]	397.53 [366.97, 427.13]	421.95 [392.07, 451.98]	396.70 [363.56, 429.29]	448.50 [409.50, 488.50]	427.92 [331.67, 516.08]	412.49 [384.81, 439.58]	395.75 [367.22, 424.32]	398.56 [380.38, 417.22]

Table S13: B1 direct costs and the ISO-NE estimate for 2025–2050 at a 2% discount rate.

Cost category or comparison	Billion 2024 USD
B1 CAPEX	203.01
B1 fixed O&M	78.24
B1 variable O&M	3.33
B1 fuel	22.41
B1 electricity imports	50.55
B1 direct-cost subtotal	357.54
ISO-NE estimate	343.57
B1 minus ISO-NE	13.97
Difference relative to ISO-NE	4.07%

Table S14: Mean source-county air-pollution damages and central 90% simulation ranges at 1.5% (million 2024 USD).

Source county	A	B1	B2	B3	C1	C2	C3	D
Suffolk, MA	5.50 [5.37, 5.63]	0.72 [0.70, 0.73]	0.75 [0.73, 0.77]	0.72 [0.71, 0.74]	0.91 [0.87, 0.95]	0.76 [0.74, 0.78]	0.72 [0.71, 0.74]	2.74 [2.70, 2.79]
Norfolk, MA	948.32 [936.78, 958.77]	261.33 [241.39, 280.82]	378.43 [355.71, 401.73]	255.78 [236.84, 274.30]	300.16 [287.45, 311.81]	330.07 [308.98, 350.73]	229.11 [211.44, 246.19]	317.51 [297.91, 336.14]
Middlesex, MA	220.56 [219.22, 221.76]	47.93 [47.60, 48.24]	48.27 [47.94, 48.59]	48.05 [47.71, 48.36]	49.41 [49.05, 49.75]	48.50 [48.15, 48.82]	48.05 [47.71, 48.36]	159.93 [158.29, 161.43]
Essex, MA	260.17 [259.61, 260.73]	121.39 [117.96, 124.71]	141.79 [138.55, 145.10]	120.05 [116.72, 123.25]	108.66 [107.39, 109.88]	132.84 [129.79, 135.79]	111.96 [108.53, 115.14]	146.82 [143.51, 149.71]
Bristol, MA	372.36 [370.56, 374.07]	167.63 [163.70, 171.44]	191.13 [187.67, 194.42]	165.49 [161.54, 169.20]	148.02 [146.10, 149.66]	180.29 [176.85, 183.72]	155.81 [151.80, 159.59]	198.82 [194.63, 202.65]
Rockingham, NH	6,928.14 [6,870.27, 6,985.03]	1,204.62 [1,179.33, 1,230.43]	1,324.49 [1,297.97, 1,352.69]	1,213.15 [1,188.15, 1,238.57]	1,423.02 [1,402.42, 1,443.23]	1,315.14 [1,289.88, 1,340.46]	1,195.50 [1,171.34, 1,220.30]	4,279.76 [4,208.51, 4,348.35]
Providence, RI	3,473.35 [3,458.26, 3,488.22]	1,334.09 [1,268.73, 1,396.19]	1,741.19 [1,674.68, 1,805.52]	1,315.00 [1,252.15, 1,373.66]	1,357.72 [1,328.29, 1,385.79]	1,574.02 [1,512.60, 1,633.22]	1,197.71 [1,137.79, 1,252.63]	3,628.60 [3,573.68, 3,677.79]
Berkshire, MA	112.02 [107.75, 115.98]	10.98 [9.49, 12.49]	18.86 [16.52, 21.22]	11.14 [9.63, 12.67]	20.26 [17.95, 22.52]	16.55 [14.39, 18.74]	9.29 [7.96, 10.65]	15.41 [13.33, 17.50]

Source county	A	B1	B2	B3	C1	C2	C3	D
Fairfield, CT	1,068.15 [1,061.71, 1,074.49]	425.93 [411.72, 439.71]	530.01 [516.21, 543.60]	423.38 [409.31, 436.29]	446.23 [441.62, 450.73]	492.46 [479.95, 504.68]	389.92 [376.23, 402.13]	1,149.95 [1,138.22, 1,160.53]
New London, CT	419.62 [415.55, 423.45]	19.05 [18.24, 19.87]	20.20 [19.29, 21.06]	19.36 [18.53, 20.19]	23.46 [22.58, 24.31]	20.86 [19.98, 21.68]	19.36 [18.53, 20.19]	170.48 [164.26, 176.55]
Worcester, MA	585.69 [576.82, 593.32]	154.91 [140.67, 168.24]	229.53 [212.77, 245.43]	152.48 [138.88, 165.20]	188.50 [178.69, 197.10]	200.53 [185.19, 214.61]	135.79 [123.43, 147.56]	192.25 [178.00, 205.49]
Hampden, MA	445.48 [439.82, 451.01]	158.90 [153.52, 164.12]	184.84 [179.63, 189.79]	156.73 [151.48, 161.77]	144.59 [141.26, 147.78]	173.12 [168.12, 178.01]	147.21 [142.04, 152.20]	206.22 [200.06, 212.35]
Newport, RI	292.87 [289.22, 296.24]	199.97 [196.84, 202.97]	222.45 [218.89, 225.82]	196.66 [193.72, 199.48]	153.04 [151.27, 154.61]	208.55 [205.59, 211.48]	186.26 [183.33, 189.04]	518.50 [516.27, 520.70]
Penobscot, ME	56.81 [55.03, 58.44]	5.10 [4.46, 5.77]	9.23 [8.18, 10.29]	5.04 [4.40, 5.68]	9.04 [8.09, 9.97]	7.65 [6.73, 8.59]	4.22 [3.64, 4.79]	6.57 [5.70, 7.44]
Oxford, ME	90.88 [90.69, 91.07]	68.43 [66.94, 69.98]	77.28 [75.71, 78.80]	66.99 [65.56, 68.39]	48.81 [48.38, 49.26]	71.67 [70.33, 73.02]	62.86 [61.41, 64.32]	66.85 [65.99, 67.65]
New Haven, CT	3,991.67 [3,950.50, 4,030.16]	1,455.97 [1,425.17, 1,483.43]	1,648.96 [1,621.23, 1,675.34]	1,444.61 [1,415.34, 1,470.75]	1,404.57 [1,392.37, 1,416.22]	1,572.48 [1,546.15, 1,597.01]	1,379.20 [1,350.43, 1,405.74]	3,230.88 [3,192.08, 3,267.49]
Windham, CT	771.45 [765.17, 777.71]	232.08 [212.44, 251.54]	339.68 [316.89, 361.70]	228.72 [209.96, 247.61]	278.54 [267.74, 288.76]	298.72 [278.45, 318.27]	204.66 [187.53, 221.74]	678.68 [659.36, 697.85]
Cumberland, ME	3,239.29 [3,190.49, 3,285.68]	809.45 [792.33, 827.09]	859.86 [843.14, 876.24]	814.96 [797.96, 831.79]	879.14 [864.98, 892.67]	860.98 [845.04, 876.89]	805.98 [789.12, 822.74]	2,305.49 [2,257.40, 2,354.34]

Source county	A	B1	B2	B3	C1	C2	C3	D
Middlesex, CT	820.05 [816.50, 823.54]	176.80 [166.42, 187.09]	236.22 [224.94, 247.24]	175.14 [164.92, 184.74]	206.28 [201.06, 211.10]	215.51 [205.38, 225.31]	161.20 [151.65, 170.44]	664.25 [650.43, 677.14]
Coos, NH	159.59 [159.00, 160.14]	124.50 [122.50, 126.29]	135.44 [133.75, 137.02]	121.91 [120.02, 123.68]	87.75 [87.06, 88.41]	127.66 [125.86, 129.35]	116.84 [114.81, 118.78]	118.76 [117.62, 119.86]
Chittenden, VT	118.20 [117.43, 118.86]	25.37 [25.23, 25.50]	25.65 [25.50, 25.78]	25.45 [25.31, 25.58]	26.26 [26.10, 26.40]	25.78 [25.63, 25.91]	25.45 [25.31, 25.58]	85.86 [85.09, 86.59]
Barnstable, MA	627.94 [621.96, 634.11]	129.12 [126.22, 131.94]	134.88 [131.97, 137.71]	130.71 [127.82, 133.49]	153.93 [151.49, 156.16]	138.03 [135.24, 140.80]	130.71 [127.82, 133.49]	397.62 [388.54, 406.28]
Merrimack, NH	5,173.56 [5,153.36, 5,191.23]	1,300.96 [1,292.95, 1,308.64]	1,322.27 [1,315.64, 1,328.57]	1,306.93 [1,299.47, 1,314.31]	1,369.47 [1,364.19, 1,374.29]	1,331.86 [1,325.85, 1,337.40]	1,306.93 [1,299.47, 1,314.31]	3,908.76 [3,870.88, 3,947.04]

Table S15: Mean source-county air-pollution damages and central 90% simulation ranges at 2% (million 2024 USD).

Source county	A	B1	B2	B3	C1	C2	C3	D
Suffolk, MA	5.12 [5.00, 5.25]	0.70 [0.69, 0.72]	0.73 [0.72, 0.75]	0.71 [0.69, 0.72]	0.90 [0.86, 0.94]	0.75 [0.73, 0.77]	0.71 [0.69, 0.72]	2.58 [2.54, 2.63]
Norfolk, MA	887.03 [875.82, 897.19]	249.64 [230.58, 268.24]	359.75 [338.09, 381.92]	244.98 [227.01, 262.70]	291.90 [279.54, 303.19]	316.12 [295.97, 335.86]	219.98 [203.07, 236.36]	305.81 [286.92, 323.71]
Middlesex, MA	207.34 [206.09, 208.47]	47.15 [46.82, 47.45]	47.48 [47.15, 47.79]	47.26 [46.93, 47.58]	48.60 [48.25, 48.93]	47.70 [47.36, 48.02]	47.26 [46.93, 47.58]	152.39 [150.87, 153.79]
Essex, MA	244.39 [243.86, 244.93]	115.98 [112.76, 119.09]	135.02 [132.00, 138.11]	114.87 [111.72, 117.89]	105.38 [104.18, 106.56]	126.99 [124.10, 129.77]	107.31 [104.06, 110.30]	140.91 [137.79, 143.63]
Bristol, MA	349.43 [347.74, 351.05]	160.19 [156.51, 163.76]	182.07 [178.83, 185.16]	158.37 [154.65, 161.87]	143.71 [141.90, 145.29]	172.39 [169.14, 175.59]	149.36 [145.55, 152.92]	190.74 [186.76, 194.36]
Rockingham, NH	6,502.24 [6,447.59, 6,555.69]	1,182.88 [1,158.37, 1,207.85]	1,297.55 [1,271.71, 1,324.68]	1,191.70 [1,167.42, 1,216.44]	1,399.82 [1,379.68, 1,419.60]	1,290.77 [1,266.35, 1,315.22]	1,175.15 [1,151.56, 1,199.26]	4,075.44 [4,008.24, 4,140.56]
Providence, RI	3,257.65 [3,242.96, 3,272.07]	1,275.40 [1,213.25, 1,334.34]	1,657.47 [1,594.76, 1,718.15]	1,259.73 [1,199.90, 1,315.38]	1,318.34 [1,289.89, 1,345.46]	1,506.99 [1,448.89, 1,562.96]	1,149.82 [1,092.72, 1,202.48]	3,382.37 [3,329.95, 3,429.47]
Berkshire, MA	103.83 [99.75, 107.61]	10.45 [9.03, 11.90]	17.93 [15.69, 20.18]	10.62 [9.17, 12.09]	19.67 [17.42, 21.87]	15.84 [13.76, 17.95]	8.88 [7.60, 10.19]	14.78 [12.77, 16.80]
Fairfield, CT	1,003.27 [997.26, 1,009.13]	408.31 [394.79, 421.32]	506.03 [493.11, 518.82]	406.56 [393.20, 418.76]	433.54 [429.14, 437.82]	472.51 [460.64, 484.07]	375.19 [362.18, 386.79]	1,069.15 [1,058.01, 1,079.18]

Source county	A	B1	B2	B3	C1	C2	C3	D
New London, CT	391.98 [388.08, 395.71]	18.92 [18.11, 19.73]	20.06 [19.15, 20.90]	19.22 [18.40, 20.05]	23.29 [22.41, 24.13]	20.71 [19.83, 21.52]	19.22 [18.40, 20.05]	163.24 [157.30, 169.00]
Worcester, MA	548.04 [539.49, 555.46]	148.11 [134.49, 160.89]	218.37 [202.46, 233.45]	146.18 [133.07, 158.36]	183.42 [173.89, 191.77]	192.26 [177.59, 205.69]	130.50 [118.73, 141.85]	185.32 [171.59, 198.05]
Hampden, MA	416.56 [411.20, 421.86]	151.91 [146.85, 156.83]	176.09 [171.18, 180.73]	150.08 [145.12, 154.84]	140.46 [137.26, 143.55]	165.63 [160.90, 170.23]	141.20 [136.32, 145.92]	197.49 [191.67, 203.29]
Newport, RI	275.37 [271.94, 278.53]	190.28 [187.39, 193.08]	210.99 [207.65, 214.11]	187.36 [184.65, 190.03]	148.00 [146.30, 149.53]	198.45 [195.73, 201.18]	177.69 [174.95, 180.28]	480.37 [478.22, 482.42]
Penobscot, ME	52.59 [50.89, 54.15]	4.83 [4.22, 5.47]	8.73 [7.74, 9.73]	4.80 [4.19, 5.41]	8.79 [7.86, 9.69]	7.30 [6.42, 8.20]	4.02 [3.47, 4.57]	6.32 [5.48, 7.16]
Oxford, ME	85.50 [85.33, 85.69]	65.04 [63.65, 66.47]	73.18 [71.73, 74.58]	63.77 [62.43, 65.08]	47.22 [46.81, 47.63]	68.12 [66.89, 69.38]	59.93 [58.57, 61.29]	63.91 [63.11, 64.65]
New Haven, CT	3,749.28 [3,710.33, 3,785.52]	1,402.39 [1,373.12, 1,428.17]	1,582.96 [1,556.97, 1,608.11]	1,393.18 [1,365.38, 1,418.08]	1,368.57 [1,356.73, 1,379.87]	1,514.89 [1,490.40, 1,537.99]	1,332.09 [1,304.53, 1,357.25]	3,047.23 [3,010.70, 3,081.67]
Windham, CT	723.62 [717.42, 729.70]	222.11 [203.28, 240.78]	323.44 [301.83, 344.44]	219.45 [201.35, 237.56]	271.08 [260.59, 280.99]	286.61 [267.17, 305.40]	196.86 [180.31, 213.28]	629.04 [610.38, 647.50]
Cumberland, ME	3,043.11 [2,997.04, 3,086.54]	792.40 [775.74, 809.67]	840.63 [824.25, 856.62]	798.06 [781.41, 814.58]	862.69 [848.76, 876.02]	842.68 [827.27, 858.22]	789.67 [773.13, 806.23]	2,194.40 [2,149.09, 2,239.98]
Middlesex, CT	768.35 [764.83, 771.80]	170.55 [160.58, 180.37]	226.55 [215.83, 236.99]	169.31 [159.47, 178.50]	201.52 [196.44, 206.18]	208.07 [198.45, 217.41]	156.23 [147.07, 165.09]	625.51 [612.35, 637.82]

Source county	A	B1	B2	B3	C1	C2	C3	D
Coos, NH	150.06 [149.50, 150.57]	118.02 [116.18, 119.67]	128.03 [126.48, 129.48]	115.71 [113.96, 117.35]	84.72 [84.07, 85.33]	121.02 [119.37, 122.56]	111.02 [109.15, 112.79]	113.23 [112.18, 114.24]
Chittenden, VT	111.13 [110.41, 111.75]	25.01 [24.87, 25.13]	25.28 [25.13, 25.41]	25.09 [24.94, 25.21]	25.88 [25.72, 26.02]	25.41 [25.26, 25.54]	25.09 [24.94, 25.21]	81.91 [81.21, 82.58]
Barnstable, MA	589.33 [583.68, 595.11]	127.00 [124.15, 129.77]	132.64 [129.78, 135.42]	128.55 [125.71, 131.28]	151.30 [148.89, 153.50]	135.74 [132.99, 138.46]	128.55 [125.71, 131.28]	379.24 [370.66, 387.39]
Merrimack, NH	4,864.09 [4,845.11, 4,880.58]	1,279.36 [1,271.48, 1,286.90]	1,300.24 [1,293.73, 1,306.43]	1,285.20 [1,277.89, 1,292.46]	1,346.42 [1,341.23, 1,351.15]	1,309.62 [1,303.73, 1,315.08]	1,285.20 [1,277.89, 1,292.46]	3,719.89 [3,685.10, 3,755.55]

Table S16: Mean source-county air-pollution damages and central 90% simulation ranges at 2.5% (million 2024 USD).

Source county	A	B1	B2	B3	C1	C2	C3	D
Suffolk, MA	4.78 [4.66, 4.89]	0.69 [0.68, 0.71]	0.72 [0.71, 0.74]	0.70 [0.68, 0.71]	0.88 [0.84, 0.92]	0.74 [0.72, 0.76]	0.70 [0.68, 0.71]	2.44 [2.40, 2.48]
Norfolk, MA	831.02 [820.09, 840.90]	238.78 [220.57, 256.53]	342.46 [321.83, 363.33]	234.92 [217.79, 251.88]	283.99 [271.97, 294.94]	303.11 [283.75, 321.99]	211.45 [195.25, 227.15]	294.78 [276.56, 312.00]
Middlesex, MA	195.24 [194.06, 196.30]	46.38 [46.07, 46.69]	46.72 [46.39, 47.02]	46.50 [46.18, 46.81]	47.81 [47.47, 48.14]	46.93 [46.60, 47.25]	46.50 [46.18, 46.81]	145.38 [143.96, 146.68]
Essex, MA	229.94 [229.45, 230.45]	110.95 [107.90, 113.87]	128.74 [125.90, 131.64]	110.04 [107.05, 112.90]	102.26 [101.12, 103.38]	121.55 [118.83, 124.17]	102.97 [99.89, 105.79]	135.36 [132.41, 137.92]
Bristol, MA	328.44 [326.84, 329.99]	153.28 [149.83, 156.63]	173.68 [170.69, 176.60]	151.74 [148.24, 155.04]	139.60 [137.86, 141.12]	165.03 [162.00, 168.04]	143.33 [139.73, 146.70]	183.14 [179.38, 186.58]
Rockingham, NH	6,112.44 [6,060.67, 6,162.67]	1,161.97 [1,138.21, 1,186.30]	1,271.82 [1,246.72, 1,297.92]	1,171.04 [1,147.48, 1,195.12]	1,377.26 [1,357.56, 1,396.62]	1,267.33 [1,243.72, 1,291.08]	1,155.50 [1,132.49, 1,178.98]	3,885.85 [3,822.52, 3,947.40]
Providence, RI	3,060.28 [3,045.72, 3,074.37]	1,220.79 [1,161.62, 1,276.45]	1,579.87 [1,520.82, 1,637.71]	1,208.18 [1,151.16, 1,261.26]	1,280.75 [1,253.24, 1,306.97]	1,444.47 [1,389.06, 1,497.20]	1,105.11 [1,050.62, 1,155.35]	3,158.22 [3,108.18, 3,203.27]
Berkshire, MA	96.37 [92.47, 99.99]	9.96 [8.59, 11.35]	17.06 [14.92, 19.23]	10.13 [8.74, 11.55]	19.10 [16.91, 21.25]	15.17 [13.17, 17.21]	8.50 [7.26, 9.76]	14.19 [12.25, 16.14]
Fairfield, CT	943.86 [938.23, 949.28]	391.87 [379.00, 404.19]	483.76 [471.64, 495.90]	390.84 [378.18, 402.36]	421.40 [417.21, 425.48]	453.87 [442.62, 464.69]	361.41 [349.00, 372.44]	995.93 [985.38, 1,005.38]

Source county	A	B1	B2	B3	C1	C2	C3	D
New London, CT	366.73 [362.99, 370.34]	18.79 [17.99, 19.59]	19.91 [19.01, 20.75]	19.08 [18.27, 19.91]	23.11 [22.25, 23.96]	20.56 [19.68, 21.36]	19.08 [18.27, 19.91]	156.45 [150.80, 161.92]
Worcester, MA	513.62 [505.30, 520.85]	141.80 [128.78, 154.09]	208.02 [192.90, 222.38]	140.29 [127.72, 151.98]	178.56 [169.29, 186.65]	184.52 [170.49, 197.36]	125.56 [114.27, 136.49]	178.77 [165.54, 191.02]
Hampden, MA	390.14 [385.03, 395.20]	145.42 [140.64, 150.05]	167.98 [163.34, 172.31]	143.89 [139.19, 148.39]	136.51 [133.43, 139.52]	158.65 [154.21, 163.00]	135.60 [130.97, 140.07]	189.31 [183.81, 194.79]
Newport, RI	259.33 [256.11, 262.31]	181.30 [178.59, 183.91]	200.41 [197.27, 203.29]	178.73 [176.18, 181.24]	143.21 [141.58, 144.70]	189.09 [186.52, 191.59]	169.72 [167.17, 172.15]	445.74 [443.69, 447.67]
Penobscot, ME	48.75 [47.12, 50.25]	4.59 [4.00, 5.20]	8.27 [7.32, 9.22]	4.57 [3.98, 5.17]	8.55 [7.64, 9.43]	6.98 [6.14, 7.84]	3.84 [3.31, 4.37]	6.08 [5.27, 6.89]
Oxford, ME	80.57 [80.41, 80.75]	61.90 [60.60, 63.23]	69.39 [68.05, 70.70]	60.78 [59.52, 62.00]	45.70 [45.32, 46.09]	64.83 [63.69, 66.00]	57.20 [55.93, 58.47]	61.16 [60.42, 61.85]
New Haven, CT	3,527.34 [3,490.62, 3,561.30]	1,352.32 [1,325.01, 1,376.63]	1,521.53 [1,497.11, 1,545.48]	1,345.01 [1,318.48, 1,368.44]	1,334.08 [1,322.46, 1,345.03]	1,461.00 [1,437.58, 1,482.58]	1,287.90 [1,261.85, 1,311.55]	2,878.64 [2,844.52, 2,911.09]
Windham, CT	679.84 [673.67, 685.75]	212.83 [194.78, 230.77]	308.38 [287.86, 328.31]	210.80 [193.48, 228.19]	263.92 [253.72, 273.55]	275.29 [256.73, 293.32]	189.57 [173.62, 205.36]	584.19 [566.19, 601.97]
Cumberland, ME	2,863.49 [2,819.91, 2,904.20]	776.05 [759.73, 792.94]	822.26 [806.20, 837.87]	781.83 [765.40, 797.98]	846.75 [833.04, 859.89]	825.13 [810.00, 840.41]	773.98 [757.75, 790.19]	2,091.20 [2,048.38, 2,133.80]
Middlesex, CT	721.06 [717.66, 724.47]	164.70 [155.09, 174.09]	217.56 [207.31, 227.46]	163.84 [154.36, 172.66]	196.94 [192.00, 201.46]	201.09 [191.90, 210.02]	151.56 [142.79, 160.04]	589.87 [577.31, 601.55]

Source county	A	B1	B2	B3	C1	C2	C3	D
Coos, NH	141.32 [140.80, 141.81]	112.04 [110.34, 113.56]	121.21 [119.79, 122.53]	109.98 [108.37, 111.49]	81.84 [81.23, 82.42]	114.88 [113.37, 116.30]	105.62 [103.91, 107.25]	108.08 [107.11, 109.01]
Chittenden, VT	104.65 [103.97, 105.24]	24.65 [24.51, 24.78]	24.92 [24.77, 25.05]	24.73 [24.59, 24.85]	25.51 [25.35, 25.64]	25.04 [24.90, 25.17]	24.73 [24.59, 24.85]	78.23 [77.59, 78.86]
Barnstable, MA	554.00 [548.65, 559.50]	124.93 [122.13, 127.65]	130.47 [127.65, 133.20]	126.45 [123.65, 129.13]	148.73 [146.36, 150.90]	133.49 [130.79, 136.18]	126.45 [123.65, 129.13]	362.12 [353.97, 369.81]
Merrimack, NH	4,580.60 [4,562.73, 4,596.00]	1,258.31 [1,250.57, 1,265.72]	1,278.78 [1,272.40, 1,284.84]	1,264.02 [1,256.86, 1,271.17]	1,323.96 [1,318.86, 1,328.61]	1,287.96 [1,282.17, 1,293.32]	1,264.02 [1,256.86, 1,271.17]	3,544.43 [3,512.38, 3,577.32]

Table S17: Mean land occupation, bird and bat mortality, and water withdrawals by pathway, with 5th–95th percentile ranges across 1,000 simulations. Units are shown for each endpoint.

Endpoint and unit	B1	B2	B3	C1	C2	C3	D
Bird and bat mortality: Onshore bats million deaths/year in 2050 from added capacity	0.077 [0.010, 0.183]	0.077 [0.010, 0.183]	0.077 [0.010, 0.183]	0.000 [0.000, 0.000]	0.077 [0.010, 0.183]	0.077 [0.010, 0.183]	0.032 [0.004, 0.077]
Bird and bat mortality: Onshore birds million deaths/year in 2050 from added capacity	0.006 [0.000, 0.033]	0.006 [0.000, 0.033]	0.006 [0.000, 0.033]	0.000 [0.000, 0.000]	0.006 [0.000, 0.033]	0.006 [0.000, 0.033]	0.003 [0.000, 0.014]
Bird and bat mortality: Solar birds million deaths/year in 2050 from added capacity	0.206 [0.008, 0.747]	0.206 [0.008, 0.747]	0.206 [0.008, 0.747]	0.000 [0.000, 0.000]	0.206 [0.008, 0.747]	0.206 [0.008, 0.747]	0.046 [0.002, 0.165]
Land occupation: Canadian Hydro million hectares	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.344 [0.173, 0.520]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]
Land occupation: New NG million hectares	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.001 [0.001, 0.001]
Land occupation: Onshore Wind million hectares	0.412 [0.131, 0.819]	0.412 [0.131, 0.819]	0.412 [0.131, 0.819]	0.000 [0.000, 0.000]	0.412 [0.131, 0.819]	0.412 [0.131, 0.819]	0.174 [0.055, 0.345]
Land occupation: SMR million hectares	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.001 [0.001, 0.001]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]
Land occupation: Solar million hectares	0.223 [0.080, 0.424]	0.223 [0.080, 0.424]	0.223 [0.080, 0.424]	0.000 [0.000, 0.000]	0.223 [0.080, 0.424]	0.223 [0.080, 0.424]	0.049 [0.018, 0.094]
Water withdrawals: New gas trillion US gallons over 2025–2050	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.048 [0.024, 0.070]
Water withdrawals: SMRs trillion US gallons over 2025–2050	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	2.575 [2.575, 2.575]	0.331 [0.331, 0.331]	0.208 [0.208, 0.208]	0.000 [0.000, 0.000]

Endpoint and unit	B1	B2	B3	C1	C2	C3	D
Bird and bat mortality: Total million deaths/year in 2050 from added capacity	0.289 [0.051, 0.787]	0.289 [0.051, 0.787]	0.289 [0.051, 0.787]	0.000 [0.000, 0.000]	0.289 [0.051, 0.787]	0.289 [0.051, 0.787]	0.081 [0.016, 0.199]
Land occupation: Total million hectares	0.635 [0.290, 1.086]	0.635 [0.290, 1.086]	0.979 [0.593, 1.452]	0.001 [0.001, 0.001]	0.635 [0.290, 1.086]	0.635 [0.290, 1.086]	0.224 [0.098, 0.398]
Water withdrawals: Total trillion US gallons over 2025–2050	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	0.000 [0.000, 0.000]	2.575 [2.575, 2.575]	0.331 [0.331, 0.331]	0.208 [0.208, 0.208]	0.048 [0.024, 0.070]

Table S18: Standard deviations of cost categories across 1,000 simulations by pathway at 2% (billion 2024 USD).

Cost category SD	A	B1	B2	B3(1)	B3(2)	C1	C2	C3	D
CAPEX	0.000	15.513	18.914	14.015	14.015	63.965	17.316	14.695	5.185
FOM	1.531	3.265	3.446	3.191	3.191	8.900	3.498	3.302	2.757
VOM	0.198	0.199	0.200	0.199	0.199	0.475	0.207	0.202	0.205
Fuel	0.307	0.481	0.501	0.470	0.470	1.541	0.511	0.474	0.474
GHG	0.723	1.963	2.166	1.889	1.889	1.042	1.956	1.788	1.993
Air emissions	0.087	0.129	0.134	0.124	0.124	0.064	0.122	0.119	0.175
Unmet demand	6.774	0.320	0.693	0.270	0.270	0.197	0.407	0.201	0.130
CAN CAPEX	0.000	0.000	0.000	0.000	11.322	0.000	0.000	0.000	0.000
CAN FOM	0.000	0.000	0.000	0.000	16.854	0.000	0.000	0.000	0.000
CAN VOM	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000
CAN CH₄	0.000	0.000	0.000	0.000	0.953	0.000	0.000	0.000	0.000
Imports NBSO	0.493	0.430	0.432	0.430	0.430	0.431	0.431	0.430	0.430
Imports NYISO	3.811	4.625	4.662	4.622	4.622	2.866	4.640	4.614	4.618
Imports QC	1.288	9.644	0.409	14.122	0.000	0.277	0.388	9.584	9.232

Table S19: Paired cost differences from B1 across 1,000 simulations at 2% (billion 2024 USD). P05 and P95 are the 5th and 95th percentiles; “Lower / 1,000” counts simulations in which the listed pathway costs less than B1.

Pathway	Mean difference	Paired SD	P05, P95	Independent SD	Correlation	Lower / 1,000
A	410.96	18.98	380.05, 442.27	21.26	0.291	0
B2	33.43	9.88	17.56, 49.59	28.05	0.876	0
B3(1)	-0.92	4.74	-8.65, 6.66	29.05	0.977	562
B3(2)	51.50	22.56	15.09, 89.81	32.28	0.529	4
C1	34.78	67.58	-76.18, 137.75	67.56	-0.001	331
C2	19.85	12.00	0.09, 39.65	26.78	0.802	49
C3	-4.78	4.35	-12.04, 2.18	27.19	0.976	845
D	56.58	13.87	34.59, 79.52	23.24	0.716	0

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