

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

Amir M. Gazar^{1,2}, Chloe Jackson³, Georgia Mavrommati³, Rich B. Howarth⁴, Ryan S.D. Calder^{1,2,5} *

¹ Department of Population Health Sciences, Virginia Tech, Blacksburg, VA, 24061, USA

² Global Change Center, Virginia Tech, Blacksburg, VA, 24061, USA

³ School for the Environment, University of Massachusetts Boston, Boston, MA 02125, USA

⁴ Environmental Program, Dartmouth College, Hanover, NH, 03755, USA

⁵ Department of Civil and Environmental Engineering, Duke University, Durham, NC, 27708, USA

* Contact: rsdc@vt.edu.

Abstract

Decarbonization planning requires comparing electricity pathways across economic, ecological and health outcomes under uncertainty. We present PHASED (Probabilistic Hourly Assessment of Scenarios for Electrical Decarbonization), which simulates hourly electricity supply and compares prescribed pathways using the same sampled inputs. At a 2% discount rate, mean monetized costs across expansion pathways and costing methods range from \$448.3 to \$509.7 billion (2024 USD, 2025–2050). For eight New England pathways over 2025–2050, we compare uncertainty in absolute costs with uncertainty in paired differences across 1,000 simulations. The standard deviation of estimates of total cost differences across pathways is roughly 1/3 that of absolute costs for a given pathway. A pathway incorporating small modular nuclear reactors lowers total monetized costs relative to the “All Options” pathway retained as the baseline planning scenario by utilities and governments. Pathways with similar mean monetized costs also differ widely in air emissions and other ecological impacts known to be of interest to stakeholders including avian mortality and water withdrawals.

Keywords

decarbonization, energy system modeling, cost-benefit analysis, uncertainty quantification, electricity dispatch

1. Introduction

Decarbonization of the electrical sector is a central component of climate change mitigation strategies in the United States and internationally ^{1,2}. In the U.S., the policy landscape governing the relative viability of plausible energy pathways has faced unprecedented volatility since January 2025, requiring the development of more flexible approaches to screening a wider variety of technologies. Federal permitting for offshore wind has been disrupted through stop-work orders, permit rescissions, and a freeze on new approvals ³. U.S.-Canada trade tensions have created uncertainty over the political viability of long-term power purchase agreements and the tariff regime applicable to spot-market imports ^{4,5}. In 2026, the governors of all six New England states issued a statement committing to explore advanced nuclear technologies including small modular reactors, marking a shift in regional attitudes toward nuclear power ⁶.

Capacity expansion models (CEMs) are widely used to identify generation portfolios that satisfy future demand while minimizing costs under technical and policy constraints such as emissions limits. However, even when extended or coupled with open-source impact screening tools, many widely used approaches remain imperfectly suited to the emerging technical and social features of the energy transition. Many are deterministic and cannot capture uncertainties inherent to systems increasingly dependent on variable renewable energy (VRE) ^{7,8}. While probabilistic models are increasingly popular, analyses commonly focus on uncertainty in absolute pathway outcomes or use uncertainty to identify robust investment portfolios, rather than explicitly retaining the covariance in outcomes across alternative pathways and quantifying uncertainty in their pairwise differences (the quantities most relevant for decision-making) ⁹⁻¹¹. Many approaches aggregate costs and benefits across space or time, limiting insight into intra-regional distributions of impacts ^{12,13}. Finally, existing frameworks often do not support exploration of sufficiently broad, policy-relevant scenario spaces or capture how project-scale interventions propagate through the system to shape regional outcomes ¹⁴⁻¹⁶.

Recent work has also argued that an over-reliance on decarbonization or renewable portfolio targets in capacity expansion modeling can obscure broader socio-environmental trade-offs across competing energy pathways, motivating tools that explicitly screen these trade-offs alongside cost and reliability ¹⁷. There have thus been recent calls for tools able to provide insights into tradeoffs at the local, project scale while using publicly available data, and for harmonized U.S.–Canada modeling capacity given the deep integration of the two systems ¹⁷⁻²⁰.

We present an energy pathway impact screening model called PHASED (Probabilistic Hourly Assessment of Scenarios for Electrical Decarbonization) and apply it to the six-state New England region served by ISO New England (ISO-NE). Here, “scenario” refers to a stylized planning option, pathway, or portfolio under consideration. New England is a timely case study because of (1) high exposure to policy instability (e.g., offshore wind permit cancellation, uncertain tariff environment) requiring greater capacity to rapidly screen costs and benefits of alternative decarbonization pathways and (2) intra-regional disagreement and debate over the magnitude and distribution of benefits and impacts of alternative energy pathways; the energy

transition has been delayed by perceptions that rural regions bear environmental and cultural costs while urban areas receive disproportionate benefits from displaced fossil fuel generation 18,21–24.

Key features of PHASED responsive to modeling gaps identified above include (1) use of historical fossil fuel generation data to represent the combination of diverse processes that would be difficult to model mechanistically including intra-regional hourly grid constraints and unit-specific maintenance schedules; (2) probabilistic representation of model inputs and outputs, including prior and posterior distributions of future hourly capacity factors of the existing generating fleet; (3) tracking of uncertainties correlated across scenarios, reducing uncertainty around inter-scenario differences rather than absolute costs; (4) flexible costing of social costs associated with Canadian hydropower; and (5) a focus on comparing tradeoffs across prescribed scenarios that may have small differences in technical performance but large differences in social acceptability or viability. PHASED uses nationally available datasets, and we include here a U.S.-wide database of hourly probabilistic generation characteristics for fossil fuel generators derived from a decade of EPA Clean Air Markets Program data allowing application to other regions.

This study uses PHASED to interrogate: (1) the decision-support benefits deriving from tracking uncertainties correlated across scenarios, notably, to better characterize total cost differences instead of absolute values; (2) the non-economic impacts and tradeoffs of alternative decarbonization pathways; and (3) the extent to which conclusions about net benefits of alternative decarbonization pathways are affected by analysis of uncertainties and environmental impacts not traditionally considered in energy decision support tools but nevertheless of interest to key stakeholders.

2. Methods

We develop a model (PHASED) to characterize the highly uncertain environmental, health, and economic impacts of diverse decarbonization pathways for New England, USA over the period 2025–2050. Pathways were developed in collaboration with local stakeholders (Section 2.1). PHASED is a substantially expanded version of an empirically grounded dispatch model originally developed to understand economics of hydropower imports to New York State (Calder et al. 2022). Its mechanics are described in Section 2.2. Modeling of greenhouse gas emissions and ambient air pollutants, and their economic costs, are described in Section 2.3. Our modeling approach for a suite of environmental impacts of interest to stakeholders but with limited reliable basis to conduct an economic analysis is described in Section 2.4. Uncertainty characterization is described in Section 2.5. Several of the below sections refer the reader to the Supplemental Information (SI) for more details. All ISO-NE, eGRID, NREL, Clean Air Markets Program Data (CAMPD) and EIA Form 860 data used are available in the GitHub repository linked in the Availability Statement.

2.1. Decarbonization pathways

We evaluate stylized alternative decarbonization pathways for New England’s electricity system to explore the bounds of likely costs and benefits over the period 2025 to 2050, summarized in Figure 1 and detailed in Supplemental Information (SI) Tables S1 (total build-out and retirement by 2050) and S2 (yearly schedule). We selected these pathways through discussion with community groups (e.g., Clean Energy New Hampshire, Concord, NH) and academic audiences^{18,26}. These discussions also informed our selection of ecological impacts of interest screened in Section 2.4. The authors retained ultimate authority on all modeling choices and inclusion or exclusion of pathways and outcomes. All pathways assume the same hourly demand profile to 2050 (SI Section 2.2).

Pathway B1 is similar to the “All Options” pathway retained by ISO-NE as the baseline planning pathway and serves as our reference pathway for constructing and comparing alternatives²⁷. B2 and B3 are also ISO-NE pathways and are compared with B1; C1–C3 and D prescribe further changes relative to B1. These pathways explore options that emerged from stakeholder and expert consultation, including different levels of offshore wind deployment, expanded electricity imports, and transmission and small modular nuclear reactors (SMR) deployment. Pathway D includes additional natural-gas capacity. PHASED was used to evaluate operational features and diverse impacts. These pathways represent selected alternatives for comparison rather than the outcome of any optimization analysis.

2.1.1. Decarbonization pathway definitions

We model select pathways already proposed and evaluated by ISO-NE in order to (1) benchmark our methodology by comparing select endpoints shared between this analysis and a study previously undertaken by ISO-NE and (2) provide more detailed information on the spatial and temporal distribution of costs and benefits for pathways already known to be of interest. We also model pathways not previously considered by ISO-NE but of interest to local stakeholders and/or the research community (e.g., implementation of SMRs).

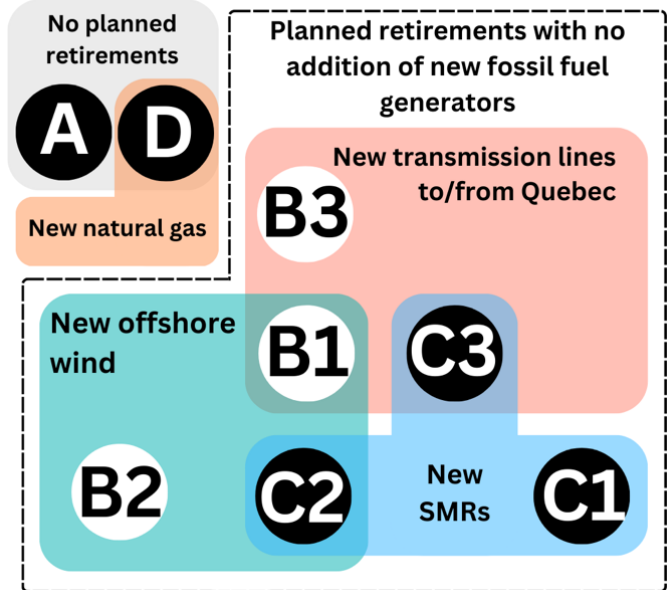


Figure 1: Euler diagram showing decarbonization pathways (circles) corresponding to different combinations of technologies (shaded rectangles). White circles show pathways considered by ISO-NE. Black circles show pathways unique to this study. Pathway D also includes expanded Québec intertie capacity (SI Table S1).

Pathway A is a no-expansion benchmark in which no new generation or transmission assets are built. Units retired before 2025 are excluded, and the remaining resources are dispatched against the same demand trajectory used for all pathways. We use Pathway A to show the consequences of demand growth without capacity expansion and to compare county-level emissions across pathways. Although its substantial unmet demand makes it unsuitable for implementation, we include it in Figure 5 as a benchmark for comparison. Pathways B1, B2, and B3 were proposed by ISO-NE as alternative pathways based on increased intertie capacity with Canada (constrained in B2) and increased offshore wind (constrained in B3). ISO-NE considers that new construction of hydroelectric generation capacity in Québec (on the order of ~9 GW, according to recent estimates by ISO-NE) would be necessary to provide the level of exports from Québec to New England in B3 ²⁷.

Pathways C1, C2, and C3 are based on deployment of SMRs, a prescribed alternative to the pathways B1-B3 and of increasing interest to the public, advocacy organizations, policymakers and other stakeholders. Recent developments such as plans to reactivate Three Mile Island in Pennsylvania to supply energy for a Microsoft data center and interest by other companies such as Amazon and OpenAI illustrate interest in nuclear power, although Three Mile Island is a conventional reactor and does not establish the prospects of SMRs ^{28–32}. Scheduling of new generators is described in Section 2.1.3.

Pathway D considers construction of new natural gas plants and is not a pathway retained by ISO-NE but may nonetheless be plausible under certain changes in energy policy, for example, rescission or expiry of credits or incentives under the Inflation Reduction Act ^{33–35}. We assume the capacity build-up for this pathway includes 1.5 GW offshore wind, 5 GW onshore wind, and 14 GW of solar PV. This pathway assumes addition of 20 GW of natural gas capacity with technical specifications drawn from CPV Towantic Energy Center combined cycle power plant located in Oxford, CT (nameplate capacity 565.5 MW), a recently constructed natural gas facility in New England that began operation in 2018.

2.1.2. *Scheduling of capacity retirements*

All pathways retain existing large nuclear capacity through 2050. Pathways A and D retain fossil units active in 2025, following the EIA “No IRA [Inflation Reduction Act] Scenario” (SI Table S3). Other pathways include scheduled retirements, a complete coal phase-out, and retirement of oil units at or below the 75th percentile of annual capacity factors in 2030, following ISO-NE assumptions ²⁷. Units remain available through their assigned retirement year. These pathways also apply NREL lifetime limits of 75 years for coal, 45 for wood, and 55 for other fossil fuel plants ³⁶. Plant ages come from eGRID and EIA Form 860 data ^{37,38}. SI Table S4 lists facility-specific retirements.

2.1.3. Build-out of new assets

ISO-NE pathways B1–B3 share 12.05 GW of added onshore wind, 64.28 GW of solar, and a common storage schedule²⁷. Offshore-wind additions are 32.64, 41.80, and 28.43 GW, with new transborder transmission of 4.1, 0, and 6.0 GW, respectively. B3 also assumes approximately 9 GW of new Canadian hydropower, added linearly over 2025–2045. Reservoir capital expenditure (CAPEX) and fixed operations and maintenance (FOM) costs follow this schedule and are scaled to New England imports (SI Figure S1); methane assumptions are in SI Table S9. Hourly storage uses an eight-hour energy-to-power ratio and 85% round-trip efficiency (SI Section 2.5).

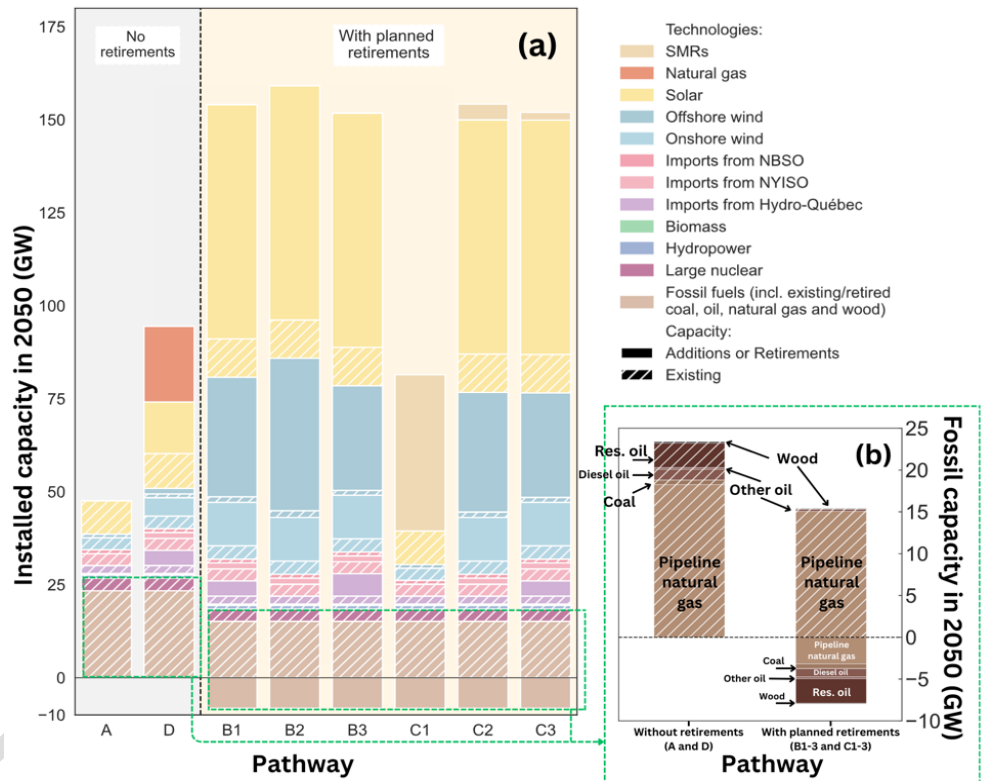


Figure 2: (a) Installed capacities by technology and pathway in 2050. Hatched bars identify existing capacity, with additions and retirements shown separately. (b) Existing fossil-fuel capacity retained in A and D, and remaining capacity and retirements in B1–B3 and C1–C3. Pathway D also adds new natural-gas capacity, shown in panel (a).

C1–C3 substitute SMRs for selected B1 additions. C1 retains B1’s retirement schedule and replaces new non-SMR capacity and transmission with SMRs. C2 replaces expanded Québec imports, while C3 replaces part of the offshore wind. SMRs are available from 2030 in 300 MW increments^{36,39}. At a 90% capacity factor, replacing 4.1 GW of imports at 95% utilization requires 4.33 GW of SMRs; C2 uses 4.2 GW. C3 uses 2.1 GW of SMRs to replace 4.215 GW of offshore wind at approximately 45% capacity factor; the ISO-NE P50 profile averages 45.51%. C1 adds seven 300 MW units annually over 2031–2050, reaching 42 GW. C2 and C3 approximate annual-generation equivalence; C1’s deployment is illustrative and is not optimized or matched to annual generation.

Pathway D adds pipeline natural gas generation in 2033, using CPV Towantic’s development timeline. Siting assumes access to pipelines and the grid, with no major state legal barriers. Candidate counties are Fairfield, Hartford, Middlesex, New Haven, New London, and Windham (CT); Newport, Providence, and Washington (RI); and Rockingham and Strafford (NH). Air-pollution damages use AP4 county assignments and damage coefficients (Section 2.3.2). These coefficients are not sampled independently, so damage variation mainly follows generation.

Figure 2 shows 2050 capacity by pathway and technology (a), and existing fossil capacity retained or retired (b).

2.2. Generation model (PHASED)

PHASED evaluates the operation and impacts of prescribed electricity generation pathways. Capacity additions, retirements, and demand are exogenous. Hourly generation, storage operation, imports, emissions, and costs are calculated conditional on these inputs. The model compares total social costs and selected ecological indicators. It does not optimize or allocate investments as a function of cost or other outcome. The model dispatch logic is described below and expands on the approach previously retained in Calder et al. (2022). Further equations, parameter tables, and intermediate outputs are available in SI Sections 2.1–2.8 and SI Table S5. Predicted generation is cross-referenced with direct costs and certain monetized impacts (Section 2.3) and other non-monetized environmental impacts (Section 2.4). A diagram of how all model inputs and outputs fit together is provided in Figure 3.

Hourly electrical demand through 2050 used to simulate generation is the “High Electrification” pathway from ISO-NE obtained pursuant to a request made under the MA Public Records Act. Hourly demand is represented as 227,904 timesteps for the period from Jan 1, 2025 to Dec. 31, 2050. The model supports less computationally intensive runs to isolate selected time periods, but results presented here are for the full model run. Details on demand forecast data are provided in SI Section 2.2.

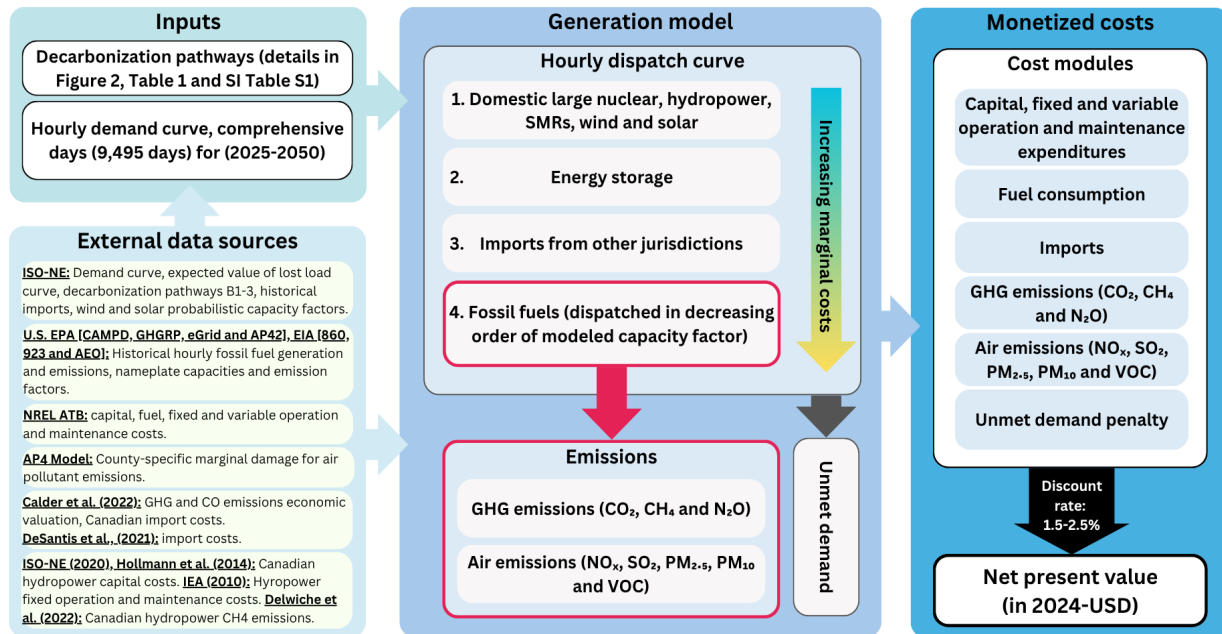


Figure 3: Relationships between data sources, decarbonization pathway and demand curve inputs, mathematical generation model, and monetized cost categories. Fossil fuel generators and air emissions are spatially resolved. Pathways are also cross-referenced with select other ecological impacts (Section 2.4). The modular setup of the PHASED model and use of nationally available data allows for other impacts to be added or for the model to be applied to other regions of the United States.

All pathways and simulations use the same hourly demand forecast. We compare pathways under common demand conditions without accounting for uncertainty in future demand. Therefore, a given simulation evaluates a pathway's possible generation and impact profile under diverse parameter values but for a constant demand curve.

At each hourly timestep, demand is served first by available local low-carbon, low-marginal-cost generation (hydropower, nuclear, SMR, solar, and onshore and offshore wind) (SI Section 2.4) and scheduled imports, including long-term imports from Québec associated with hourly import commitments (SI Section 2.6). Aggregate biomass follows these resources and imports, before storage and the existing thermal fleet.

Fossil unit output for all generators is calculated by (1) sampling from distributions specific to the generator and hour-of-year and then (2) removing, in ascending order of capacity factor (i.e., least economical units first) any excess capacity (SI Section 2.7). Backward and forward adjustments use future and preceding sampled output to limit hourly ramps. This procedure does not simulate day-ahead market clearing or guarantee a least-cost commitment schedule. If available low-carbon generation, storage, new gas, and adjusted existing-fleet generation (dispatched in increasing order of marginal costs but limited to ramping limits) do not satisfy

demand, imports are increased within remaining intertie headroom. If renewables/low-marginal-cost generation exceeds demand, batteries charge subject to the clean-generation charging restriction (SI Section 2.5), with remaining surplus recorded separately (i.e., curtailments).

Uncertainty in future hourly utilization of fossil fuel, wind, and solar assets is modeled by using Monte Carlo analysis. ISO-NE supplies stochastic hourly wind and solar profiles derived from climate data, including technology-specific annual-percentile capacity factors. PHASED samples the solar, onshore, and offshore stochastic hourly capacity factors randomly (SI Sections 2.4.1 and 3).

Our approach models fossil-fuel generation output and exchanges with other regions using historical observations, which has the advantage of capturing both (1) features that might otherwise be modeled mechanistically using publicly available data, including approximate merit order dispatch and minimum output levels and (2) features that are difficult to represent explicitly because of data limitations or complex dynamics, including unit-specific operating conditions, planned and unplanned outages, maintenance, granular market conditions, and fine-scale transmission constraints. This approach builds on our earlier dispatch-curve methodology, which likewise used observed generator utilization to approximate dispatch while recognizing that a fully mechanistic model could instead represent ramping, minimum output, and related constraints explicitly ²⁵.

A more fully mechanistic representation would not eliminate uncertainty, but would partly shift it into a more complex model structure and parameterization. Such models require more detailed assumptions about operating constraints, outages, reserves, transmission, and market behavior, and model results can be sensitive to those choices ^{15,40,41}. Operating data therefore provide a parsimonious means of retaining the joint effects of many observed and unobserved constraints.

We incorporate storage to assess the integration of renewables, reliability, and system costs ¹⁹. We use an eight-hour energy-to-power ratio and an 85% round-trip efficiency, with symmetric one-way efficiencies of $\sqrt{0.85}$. In this study we allow carryover between days and assume no hourly self-discharge, however, the model can be configured to allow for self-discharge.

The dispatch model is described in more detail in SI Sections 2.3 (overall mathematical formulation of dispatch), 2.4, (low-carbon generation), 2.5 (battery storage), 2.6 (imports), 2.7 (fossil fuel generation and emissions), and 2.8 (curtailments and unmet demand). Monte Carlo analysis is described in SI Section 3.

2.3. Direct costs and monetized environmental impacts

Build-out of new infrastructure (main text Section 2.1), fixed operational and maintenance (O&M) and fueling costs of all generation infrastructure are cross-referenced with direct cost tables (Section 2.3.1) and generator-specific emissions tables, which are then cross-referenced with emissions costs (Section 2.3.2). Hours where available resources cannot satisfy demand are assigned an unmet demand penalty (Section 2.3.3). All costs are expressed in 2024-USD based

on the Bureau of Labor Statistics Consumer Price Index ⁴². The model supports diverse discount rates, but results presented here use a discount rate of 2% based on the 2023 revisions to Office of Management and Budget (OMB) circular A-4 ⁴³. We also apply 1.5% and 2.5% in a sensitivity analysis. This relatively low rate is appropriate because greenhouse gas emissions are valued using Social Cost of Carbon estimates, which are intended to reflect long-run climate damages and are commonly paired with relatively low discount rates in recent policy guidance. This approach is also consistent with prior state-level guidance used in decarbonization policy analysis, including New York State guidance ⁴⁴.

2.3.1. *Direct costs*

Direct costs include new generation and intertie capital expenditures (CAPEX), fixed O&M, variable O&M, and fuel and electricity purchases (cost components). Generation coefficients come from the 2024 NREL Annual Technology Baseline (ATB) input, converted from 2022 dollars to January-2024 dollars ³⁶. Where the source data provide lower and upper cost estimates, we represent uncertainty by drawing, for each simulation and each technology-cost component combination, a value uniformly between those bounds. The same draw is applied to that cost component in every year and pathway within the simulation, so that common cost uncertainty is preserved when pathways are compared; different technology-component combinations are sampled independently. Fossil-fuel prices are specified by year rather than sampled, although total fossil-fuel costs vary with modeled generation. Import-purchase, intertie, and Canadian hydropower cost assumptions are treated similarly where lower and upper estimates are available. Land-acquisition costs are included in CAPEX, while physical land occupation is reported separately. Section 2.5 describes the treatment of uncertainty and paired pathway comparisons; detailed cost sources and calculations are provided in SI Section 2.9 and Table S6.

We evaluate costs at discount rates of 1.5%, 2%, and 2.5%, using shared cost-coefficient draws and the corresponding EPA 2023 greenhouse gas cost schedule. Costs are calculated from annual dispatch outputs. Each simulation has eight physical pathways, with B3 reported under two costing methods. Cost components sum to total cost, and all complete simulations are included.

2.3.2. *Greenhouse gases and air pollutants*

As described in Section 2.2, hourly fossil-fuel generation is linked to generator- or technology-specific emissions factors for greenhouse gases (CO₂, CH₄, and N₂O) and air emissions (SO₂, NO_x, VOC, PM_{2.5}, and PM₁₀). For existing units, hourly CO₂, NO_x, SO₂, and heat-input rates are estimated from historical CAMPD observations ⁴⁵. Where supported by sufficient data, emission rates vary with unit loading and ramping behavior; otherwise, load-dependent or unit-average emission rates are used. The appropriate emission rate structure for each unit and pollutant is selected using held-out prediction error, with details provided in SI Section 2.13.

Missing generation profiles and missing emissions-rate information are handled separately. The dispatch metadata contain 152 existing fossil-fuel units, of which 118 are active in 2025; 110 of

these active units are represented in the hourly dispatch dataset, while eight (6.8%) are absent. Units without represented dispatch output are retained in the supporting inventory for provenance but do not contribute to calculated emissions damages. For represented units with insufficient unit-specific emissions data, the model first falls back to the unit-average emission rate; where unit-level history is insufficient altogether, a pre-estimated unit or fuel/unit-type proxy is used. We create the fall back dataset using CAMPD historical data and import it to our simulations as part of the fossil fuel datasets.

The CAMPD dataset does not include generator-specific emission factors, such as non-biogenic CO₂-eq for CH₄ and N₂O emissions, PM rates and ratios, or estimated CO and VOC emissions. For these pollutants, we use fuel type to estimate the emission rates, as provided in SI Table S7.

Greenhouse gas masses are multiplied by fixed, year-specific social-cost schedules following U.S. EPA (2023). CO₂, CH₄, and N₂O are valued separately. B3(2) additionally attributes specified Canadian reservoir methane emissions; B3(1) excludes this Canadian generation-side term. B3(1) and B3(2) are thus two costing alternatives for a common pathway (SI Sections 2.11–2.12). We note that the 2023 Circular A-4 was rescinded in February 2025⁴⁷, and M-25-27 directed agencies to limit consideration of greenhouse gas emissions in regulatory and permitting decisions to statutory requirements⁴⁸. However, these changes are not consistent with cost-benefit guidance elsewhere, particularly on the State level, which is more relevant here, and the long-term future of current federal guidance is in any case uncertain.

Air-pollution damages are calculated from facility emissions and marginal damage coefficients. We use AP4⁴⁹ for NO_x, SO₂, PM_{2.5}, and VOC, matching existing facilities to electric-generating-unit records where available. AP4 calculates marginal damages from exposure to ambient air pollutants downwind of emission sources located in counties across the United States, including in counties other than the emission county. Source-county identifiers come from the supplied facility metadata.

Of the 110 existing units represented in the dispatch output, 100 are matched directly to AP4 electric-generating-unit records. The remaining 10 units (9.1%) are assigned the AP4 county-level non-generating-unit coefficient for their source county. For hypothetical new natural-gas units, we assign coefficients from a specified existing generating unit; Table S8 identifies the direct match, county proxy, or the existing generating unit used for every modeled fossil fuel unit. PM₁₀ is calculated as the difference between PM and PM_{2.5}. Its damage coefficient comes from AP3⁵⁰ because this coefficient is unavailable in the AP4 tables used here. CO uses a separate published cost range. AP4 coefficients are converted from 2020 USD per metric tonne to the common 2024 price basis. SI Table S8 provides the resulting source-specific coefficients and match type used in the analysis.

2.3.3. *Unmet demand penalty*

In our sequential (hour by hour) dispatch calculation, renewable capacity factors and import capability factors are drawn exogenously from the Monte Carlo random stream (one draw per

hour for each technology and intertie) and are not resampled in response to shortages; conditional on these realizations, carbon-free generation and imports serve demand first, storage discharges only when carbon-free generation plus imports are insufficient, and (with charging restricted to surplus carbon-free and imports) storage charges only from surplus low-carbon generation and imports; while the model supports optional grid charging from thermal output, all results presented here use curtailment-only charging. Fossil generation is then scheduled to cover any remaining residual demand subject to an hourly sampling and ramp adjustments that can shift some fossil output earlier than the hour of need; any resulting surplus is accounted for as curtailment in the energy balance (that is, it is not used to charge storage under our assumptions). After all available resources have been dispatched, any excess demand is assigned an unmet demand penalty of \$3,500 per MWh based on ISO-NE guidance. The pay-for-performance rate and ISO-NE value-of-lost-load curve are shown in SI Figure S2. The reported costs use the fixed \$3,500/MWh penalty. The ramp adjustment uses future sampled output; it does not minimize an objective function. Unmet demand is explained in more detail in SI Section 2.14.

2.4. Non-monetized ecological impacts

Beyond greenhouse gases and other air emissions with robust, widely used tools for monetization (described in SI Section 2), we screened pathways by impact on several other ecological and land-use endpoints. Stakeholder engagement identified land occupation, bird and bat mortality, cooling-water withdrawals and viewshed impacts as local concerns (Section 2.1). These ecological impacts are reported in their physical units and compared alongside total social costs. They reveal trade-offs for decision-makers to weigh but are not monetized, added to the monetary total, or combined into a single ecological ranking.

Table 1 lists the range of impact for each technology with available references; where estimates are pooled from multiple studies, individual studies are tabulated in the indicated SI tables. Impacts that are unique to one technology studied (e.g., nuclear waste disposal) or whose outcomes cannot be reported in common units are not compared. While our method of calculating CAPEX (Section 2.3.1) includes direct costs of land acquisition for new generation and transmission, we calculate land use requirements separately here as a proxy for the potential complexity of land acquisition, stakeholder engagement, environmental assessment, and other features that affect implementation of land-intensive projects.

Bird and bat mortality is calculated by multiplying added solar and onshore-wind capacity in 2050 by the corresponding annual mortality coefficients. It is reported as an annual endpoint, rather than cumulative deaths over 2025–2050. Cooling-water withdrawals are calculated from simulated new-gas and SMR generation over 2025–2050; the gas coefficient is sampled from the Uniform(15,50) US gal/MWh range in Table 1.

Table 1: Ecological impact coefficients and resource requirements. Distribution parameters are retained, with the implied mean and central 90% coefficient range for readability. Fixed estimates and visibility limits are not probability intervals.

Technology	Coefficient distribution; mean [P05, P95]	Unit	Citations
<i>Bird and bat mortality</i>			
On-shore wind	Gamma ($\alpha = 0.20$, $\theta = 2.54$); 0.508 [<0.001 , 2.618]	bird deaths MW ⁻¹ year ⁻¹	51
	Gamma ($\alpha = 1.538$, $\theta = 4.160$); 6.398 [0.782, 16.528]	bat deaths MW ⁻¹ year ⁻¹	52
Solar	Lognormal ($\mu = \log(1.214)$, $\sigma = 1.409$); 3.276 [0.120, 12.324]	bird deaths MW ⁻¹ year ⁻¹	53
<i>Land occupation</i>			
Hydropower reservoirs	Uniform (43.1, 146.7); 94.9 [48.28, 141.52]	hectares MW ⁻¹	SI Table S9
Natural gas	0.032 ^b	hectares MW ⁻¹	54
On-shore wind	Gamma ($\alpha = 3.695$, $\theta = 9.382$); 34.666 [11.184, 68.641]	hectares MW ⁻¹	55
Small modular nuclear	0.017	hectares MW ⁻¹	56
Solar	Gamma ($\alpha = 4.25$, $\theta = 0.82$); 3.485 [1.241, 6.649]	hectares MW ⁻¹	57
<i>Viewshed</i>			
High-voltage transmission	$\leq 27^a$	km	58
Off-shore wind	$\leq 40^a$	km	59
Solar	$\leq 5^a$	km	60
<i>Water withdrawals for thermal generation</i>			
Natural gas (dry-cooled)	Uniform (15, 50); 32.5 [16.75, 48.25] (c)	gal MWh ⁻¹	54,61
Small modular nuclear (water-cooled)	740 ^d	gal MWh ⁻¹	62

^a Maximum visibility distance assuming flat terrain, visibility drops off sharply with terrain/vegetation

^b Based on CPV Towantic Energy Center, Oxford, Connecticut.

^c The natural-gas withdrawal range is 90% below the wet recirculating cooling estimate of 150–500 US gal/MWh ⁶¹.

^d Based on the NuScale estimate reported by Idaho National Laboratory (2018).

2.5. Uncertainty and paired comparisons

PHASED represents uncertainty in generation availability, imports, and selected cost inputs where data are available to support a probabilistic formulation. Hourly solar, onshore-wind, and

offshore-wind availability is sampled from technology-specific percentile profiles provided by ISO-NE (Table S5); hourly fossil-fuel generation is sampled from unit-specific empirical distributions derived from EPA CAMPD data (Tables S4–S5); and availability of non-contracted imports is sampled from historical intertie utilization (Table S5). These sampled quantities are propagated through hourly dispatch. Demand, prescribed capacity additions and retirements, nuclear, hydropower and biomass capacity factors, and storage operating parameters are fixed across simulations (Tables S1–S5). Table S5 summarizes generation-model inputs, their sources, and whether they are sampled or fixed.

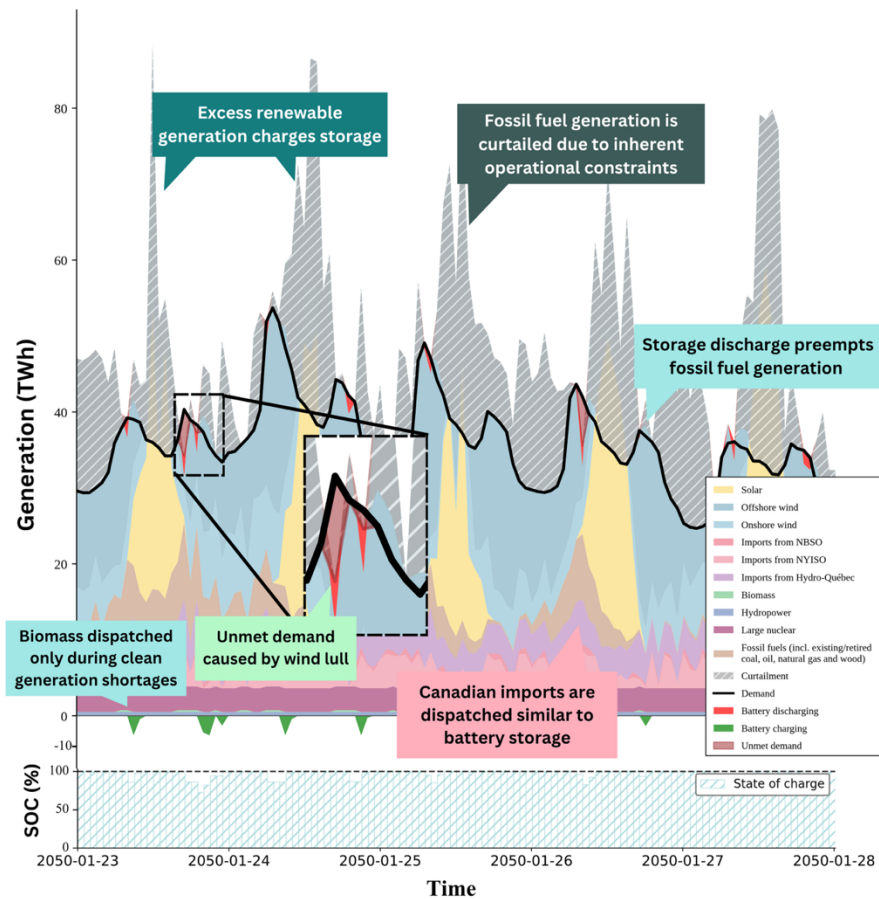


Figure 4: Winter wind lull and peak annual demand model results for pathway B1 (Simulation #1 out of 1,000, 23rd to 28th January 2050).

Uncertainty in direct costs is represented where source data provide a range of plausible values. For each technology and cost component, CAPEX, fixed O&M, variable O&M, non-fossil fuel costs, and applicable import, intertie, and Canadian hydropower costs are sampled uniformly between specified lower and upper estimates (Table S6). Fossil-fuel prices are fixed by year, although total fossil-fuel costs vary with simulated generation (Table S6). Detailed sources and calculations for generation costs, imports, and Canadian hydropower are provided in SI Sections 2.9–2.11, respectively, and Table S6 summarizes the probabilistic treatment of each cost input.

Each simulation uses the same sampled inputs for every pathway, so pathway differences are calculated under matched realizations of uncertain conditions. We report both absolute pathway cost distributions (Tables S10–S12) and paired cost differences relative to B1 (Table S19). Cost-component variability across simulations is reported in Table S18.

3. Results and discussion

3.1. Hourly operational dynamics

PHASED represents operational dynamics in a decarbonized power system at hourly resolution. Figure 4 illustrates model behavior during a January 2050 winter wind lull and peak-demand period under pathway B1. During this period, shortfalls in wind generation are met through a combination of electricity imports, storage discharge, and remaining dispatchable generation. Canadian hydropower imports are dispatched subject to hourly transmission constraints and assumptions regarding baseload and demand-responsive imports, while fossil generation is subject to the ramping and capacity constraints described in Section 2.

Across the 1,000 simulations of each of the eight pathways over 2025–2050, annual generation and emissions totals reconcile with the corresponding facility-level summaries, and the maximum recorded hourly energy-balance error was 0.005 MWh. These checks demonstrate internal costing consistency rather than independently validating the operational realism of the modeled system.

The hourly results also illustrate the magnitude of temporal mismatch that can remain in a highly decarbonized system. Under B1, mean cumulative surplus generation was 2,034.2 TWh, equivalent to 44.98% of cumulative demand, while mean cumulative unmet energy was 3.124 TWh over 2025–2050. Surplus and shortages occur in different hours and therefore can coexist over the simulation horizon. Moreover, the modeled surplus includes generation associated with thermal ramping constraints and should not be interpreted exclusively as curtailed renewable generation.

Finally, the common simulation structure permits uncertainty to be characterized both for individual pathways and for differences between pathways. The same uncertain realization is applied across alternative pathways within each simulation, allowing paired comparisons to retain covariance in shared inputs. Accordingly, the results below report empirical distributions of absolute pathway outcomes as well as paired differences between alternatives, which are more directly relevant to comparative decision-making.

3.2. Benchmarking, monetized pathway costs, and correlated uncertainty

PHASED produces direct-cost estimates broadly comparable in magnitude to those of the ISO New England Roadmap for overlapping pathways. For B1 (“All Options”), mean direct costs were \$357.54 billion, approximately 4.1% higher than the Roadmap estimate of \$343.57 billion (2024 USD, 2025–2050, 2% discount rate; Table S13). The estimates are not directly equivalent because the analyses differ in both included cost categories and the timing of expenditures. For example, PHASED records capital expenditures when capacity is added, whereas the Roadmap spreads capital costs over the life of the asset; the Roadmap also includes energy-efficiency measures and zero-carbon liquid and gas imports that are not explicitly represented here. We therefore use this comparison as a benchmark of overall cost magnitude rather than a strict validation of individual cost components.

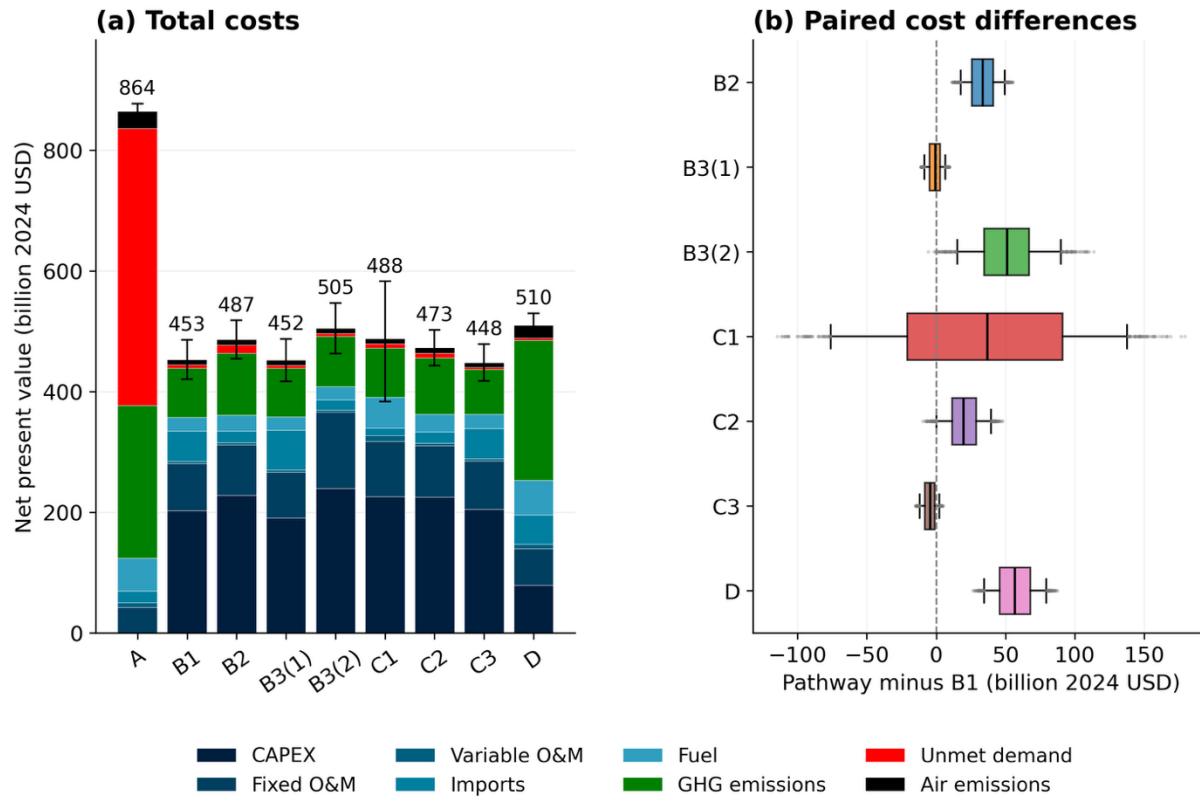


Figure 5: Monetized pathway costs at a 2% discount rate in billion 2024 USD. Panel (a) shows mean component costs and empirical 5th–95th percentile ranges. Panel (b) shows paired pathway differences relative to B1. Boxes span the 25th–75th percentiles, black lines mark medians, whiskers extend to the 5th and 95th percentiles, and points show the remaining draws. All 1,000 simulations are retained.

Figure 5 and Tables S10–S12 compare total monetized costs, including direct system costs, greenhouse-gas damages, and air-pollution damages. At the 2% reference rate, mean total costs were \$453.10 billion for B1, \$486.53 billion for B2, \$452.18 billion for B3(1), \$504.60 billion for B3(2), \$487.88 billion for C1, \$472.95 billion for C2, \$448.32 billion for C3, and \$509.68 billion for D. Pathway A had a mean cost of \$864.07 billion; because it assumes no expansion of generation or transmission and consequently incurs substantial unmet-energy costs, it serves as a no-expansion reference rather than an implementable alternative. Among the expansion pathways, C3 had the lowest mean monetized cost at the 2% reference rate. Tables S10–S12 report the corresponding 5th–95th percentile ranges across simulations.

The treatment of Canadian hydropower illustrates how the cost accounting method can affect comparisons among pathways. B3(1), which includes the cost of purchased Québec electricity, has a mean cost nearly identical to B1 (\$452.18 versus \$453.10 billion). Under B3(2), these import costs are instead replaced by estimated costs associated with the additional Canadian hydropower needed to supply the modeled imports, including capital and operating costs and reservoir methane damages; mean cost rises to \$504.60 billion. B3(1) and B3(2) therefore

represent two different methods of costing for the same pathway. The difference between them shows that the apparent cost of expanded Canadian imports depends substantially on whether the analysis counts the purchase price of imported electricity or estimates the costs associated with producing that additional electricity in Québec.

Figure 5 also illustrates the importance of costing for uncertainties shared across pathways. In panel (a), the absolute cost distributions of several pathways overlap substantially, particularly B1, B3(1), and C3. Such overlap provides relatively little information about which alternative is likely to be less costly because much of the uncertainty affecting one pathway also affects the

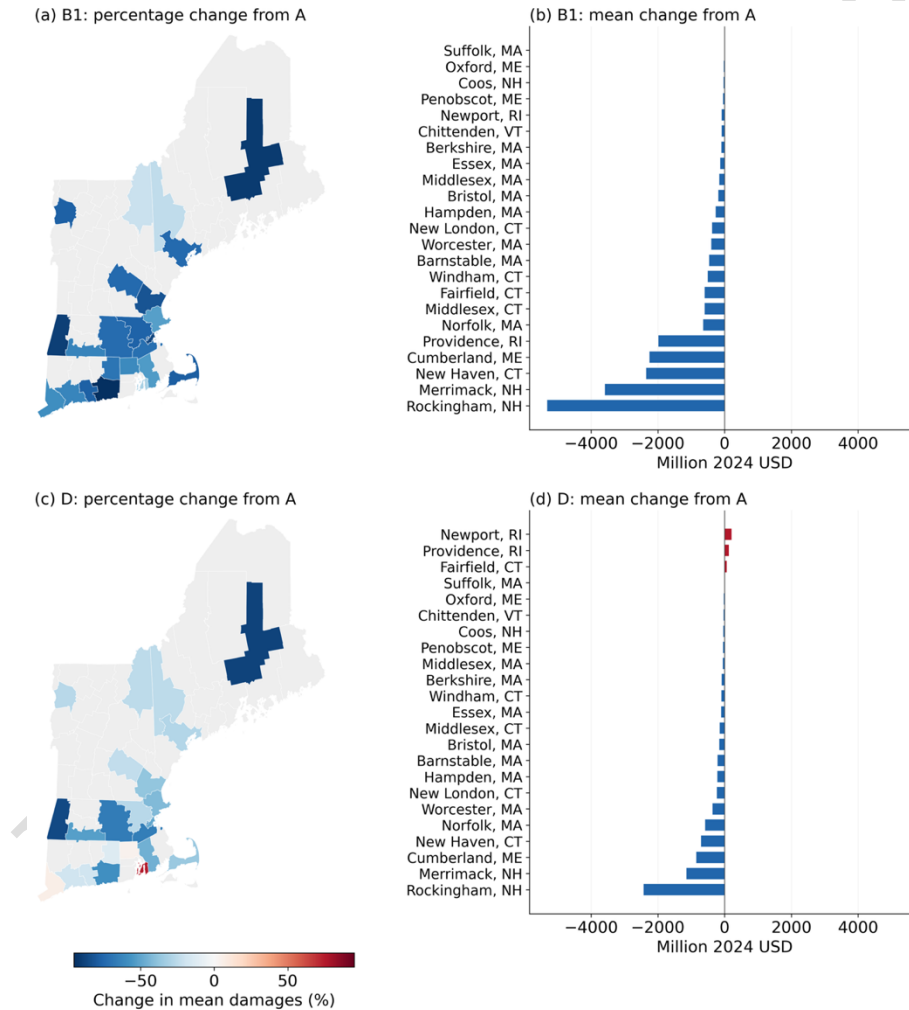


Figure 6: Changes in mean air-pollution damages attributed to source counties for B1 and D relative to A, at a 2% discount rate. Maps (a, c) show $100 \times (\text{pathway mean} - \text{A mean}) / \text{A mean}$. Bar charts (b, d) show the corresponding mean change in million 2024 USD. Means are calculated across 1,000 simulations. Blue indicates a decrease and red an increase. Grey counties have no represented source or an undefined percentage because the A mean is zero. Source counties identify emitting facilities; the associated damages can occur elsewhere.

others. Panel (b) instead compares pathways within the same simulations, using the same sampled conditions for each alternative. These paired comparisons preserve the covariance created by shared inputs and therefore provide more direct information about the cost consequences of choosing one pathway rather than another.

For example, at 2%, B2 minus B1 had a mean difference of \$33.43 billion and a paired standard deviation of \$9.88 billion; B1 was less costly in all 1,000 paired simulations. If the same marginal variances were instead combined without accounting for covariance, the

standard deviation of this difference would be \$28.05 billion. Thus, comparing the pathways as if their uncertainties were independent would substantially overstate uncertainty about the additional cost of B2 relative to B1.

The comparison between C3 and B1 further illustrates why paired differences are more informative than comparing their absolute cost distributions. At 2%, C3 minus B1 had a mean of $-\$4.78$ billion, a standard deviation of $\$4.35$ billion, and a 5th–95th percentile range of $-\$12.04$ to $\$2.18$ billion; C3 was less costly than B1 in 845 of 1,000 paired simulations. The absolute cost distributions for C3 and B1 overlap substantially, which by itself provides little indication of which pathway is generally less costly. By comparing the two pathways under the same sampled conditions, however, the paired analysis shows much more clearly that C3 tends to have lower costs than B1. Although the paired range still spans zero, the results provide stronger evidence that C3 is more likely to be the lower-cost pathway under the uncertainties represented in the model than is apparent from the overlapping absolute distributions alone.

The SMR pathways also illustrate the distinction between lower mean costs and exposure to relatively high-cost outcomes. Although C3 has the lowest mean cost among the expansion pathways, its paired range relative to B1 spans zero. C1, which includes more extensive SMR deployment, has a substantially wider 5th–95th percentile total-cost range ($\$383.69$ – $\$582.57$ billion) than B1 ($\$420.36$ – $\$485.63$ billion), consistent with the broad range of assumed SMR capital costs (Table S11). Comparisons among these pathways therefore depend not only on mean costs but also on how decision-makers weigh the possibility of comparatively high-cost outcomes.

Cost comparisons were also evaluated under 1.5%, 2%, and 2.5% discount rates. These rate cases alter both direct-cost discounting and the effect of the discount rate on greenhouse gas valuation. C3 retained the lowest mean cost among the expansion pathways at all three rates, with mean NPVs of $\$527.33$ billion at 1.5%, $\$448.32$ billion at 2%, and $\$395.75$ billion at 2.5%. Changing the discount rate had relatively modest effects on the relative costs of most expansion pathways but substantially affected the comparison of D with B1. Relative to B1, B2's mean cost difference declined from 9.2% at 1.5% to 7.4% at 2% and 6.1% at 2.5%, while C1 remained approximately 7–8% more costly than B1 across all three rates. In contrast, D's mean cost difference relative to B1 declined from 30.4% at 1.5% to 12.5% at 2% and 0.3% at 2.5%. This greater sensitivity reflects D's substantially higher greenhouse-gas emissions and the corresponding effect of the discount rate on monetized greenhouse-gas damages.

3.3. Geographic and ecological distribution of pathway impacts

Figure 6 compares changes in monetized air-pollution damages attributable to emissions sources in each county for pathways B1 and D relative to pathway A at the 2% discount rate. The maps show percentage changes relative to A, while the accompanying bar charts show changes in mean damages in monetary terms. SI Tables S14–S16 provide county-level results at 1.5%, 2%,

and 2.5%. These results identify the counties in which the emissions responsible for estimated damages originate rather than where the health effects are realized.

The geographic pattern nevertheless provides information relevant to regional debates over the distribution of the costs and benefits of decarbonization. Under B1, substantial reductions in source-attributed air-pollution damages occur throughout New England, including in northern and more rural parts of the region. Approximately 56% of the regional reduction in mean air-pollution damages from A to B1 at 2% is attributable to emissions sources in New Hampshire and Maine (Table S15), with reductions associated with sources in counties including Coos, Oxford, and Penobscot. This pattern broadens the regional siting discussion beyond a simple contrast in which northern New England communities host energy infrastructure while the principal benefits accrue to electricity consumers in Massachusetts²³.

The contrast between B1 and D further demonstrates that the location and magnitude of these reductions depend on the generation pathway. B1 produces broad reductions in source-attributed damages, whereas D produces smaller reductions and increases in some counties relative to A. These geographic differences would be obscured by comparison of regional totals alone. This result is consistent with previous work showing that changes in generation and transmission can redistribute air-pollution damages across locations (Calder et al., 2022) and with studies emphasizing the importance of spatially explicit analysis when evaluating power-plant retirement and decarbonization strategies (Campos Morales et al., 2024).

Air-pollution damages also represent only one component of the environmental consequences of the pathways. At 2%, mean greenhouse-gas damages under B1 are approximately \$81.54 billion, compared with \$8.17 billion in monetized air-pollution damages, so greenhouse-gas damages dominate the environmental costs included in the monetary totals. Other impacts identified as important in the stakeholder process cannot readily be represented in the same monetary metric. Figure 7 therefore compares land occupation, bird and bat mortality, visibility of energy infrastructure, and cooling-water withdrawals in their original physical units rather than combining them into a single environmental score.

B1 and B3(1) have similar mean costs, but B3 occupies 0.979 million hectares compared with B1's 0.635 million, with Canadian reservoirs accounting for the difference. Estimated bird and bat mortality is 0.289 million deaths annually in 2050 for B1, B2, B3, C2, and C3. C1 occupies less land and has no modeled mortality from added solar or onshore wind, but requires 2.575 trillion US gallons of cooling water over 2025–2050, compared with 0.331 trillion for C2 and 0.208 trillion for C3. Visibility (Figure 7c) does not measure ecological damage or community acceptance. These estimates depend on facility locations, terrain, vegetation, species, habitat, and cooling design. Similar costs therefore mask different ecological impacts.

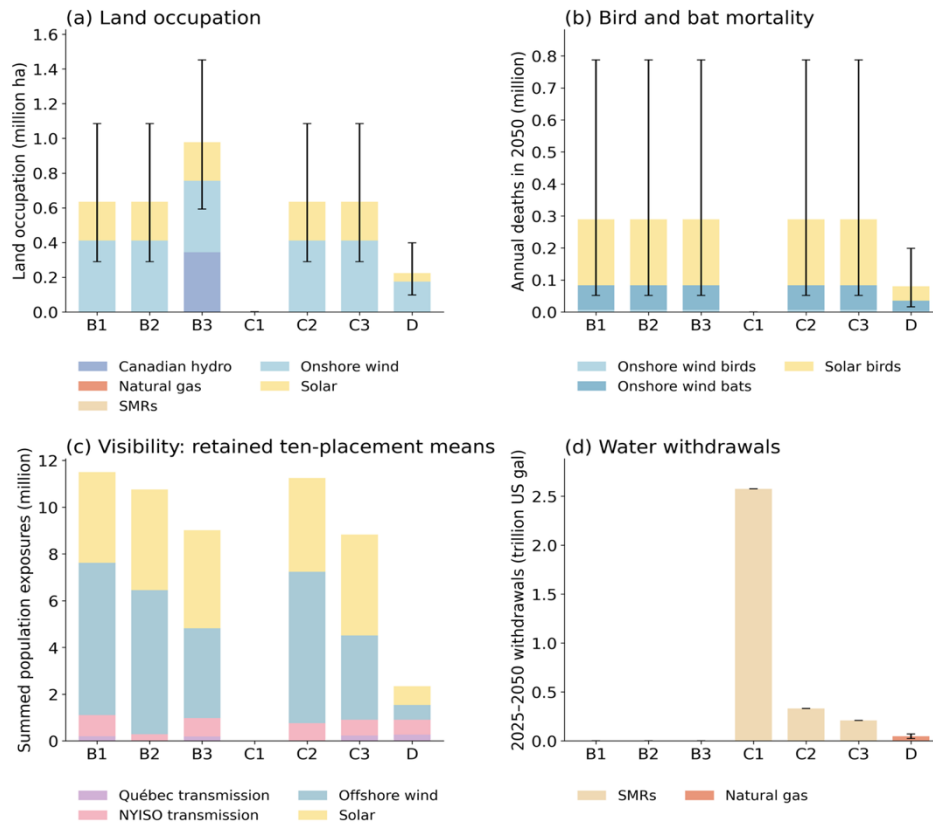


Figure 7: Physical ecological impacts by pathway. Stacked bars show mean technology contributions to (a) land occupation from capacity added by 2050, (b) annual bird and bat mortality in 2050, (c) population exposure to visible infrastructure and (d) cooling-water withdrawals over 2025–2050. Error bars in (a), (b) and (d) show the 5th–95th percentiles across 1,000 simulations. Panel (c) shows mean summed exposures from ten random placement trials; a person may be counted for more than one technology.

Taken together, Figures 6 and 7 show why regional cost comparisons alone provide an incomplete characterization of decarbonization pathways. Pathways with similar monetized costs can differ in where emissions reductions originate, how much land is occupied, the types of wildlife impacts anticipated, the visibility of new infrastructure, and demands on water resources. No single pathway minimizes all of these impacts, making the geographic and ecological consequences of the technology mix relevant alongside the cost comparisons in

Section 3.2.

3.4. Scope and limitations

PHASED can be adapted to other U.S. regions using local demand, generator, and intertie data, provided that the required inputs are available. Section 5 provides a U.S.-wide database of fossil-fuel generators with hourly-scale probabilistic generation characteristics to facilitate such applications. The present analysis does not represent investments in intra-regional transmission or constraints on power flows within New England; incorporating these features would permit finer-scale evaluation of transmission requirements and costs within each pathway.

All pathways represent prescribed technology and infrastructure deployments and should be interpreted as conditional comparisons rather than forecasts of future uptake. The simulations

therefore evaluate the consequences of assuming that each specified pathway is implemented, rather than estimating the likelihood that particular technologies, capacities, or deployment schedules will occur. Uncertainty is represented for selected modeled parameters within those prescriptions (e.g., SMR cost coefficients are sampled within specified ranges) while other assumptions, such as SMR capacity factor, deployment schedules, and technology availability, are fixed. The results therefore characterize uncertainty conditional on the pathway definitions rather than the full uncertainty surrounding future technology adoption or project completion. Other emerging technologies, including long-duration energy storage and hydrogen-based energy systems, could be evaluated if corresponding operational, cost, and environmental-impact data were incorporated.

All pathways also use the same prescribed demand trajectory. Alternative hourly demand trajectories, including greater demand growth associated with data centers or other forms of electrification, could change generation requirements and pathway comparisons and are not represented in the current analysis. Additional ecological, health, or economic outcomes could likewise be incorporated where suitable data and methods are available; for example, regional employment and economic-development effects could be evaluated using tools such as NREL's Jobs and Economic Development Impact models ⁶³.

Finally, the model characterizes differences in expected costs and the distribution of costs across the uncertainties included in the analysis, but it does not determine how decision-makers should value those differences. For example, a pathway with a lower mean cost but a wider range of possible costs may be preferred differently depending on tolerance for high-cost outcomes. The paired comparisons presented here are therefore intended to make these tradeoffs more transparent rather than to identify a single preferred pathway.

4. Ethics declaration

The authors declare no competing interests.

5. Data and computer code availability statement

Model code, input data and instructions for reproducing the analysis are provided in the project repository (<https://github.com/amirgazar/Decarbonization-Tradeoffs>). U.S. wide power-plant and CAMPD data, all model inputs, 1,000-simulation summaries, and a detailed sample Simulation results are provided in the project GitHub website (<https://amirgazar.github.io/us-powerplants-phased/index.html>). Power-plant and CAMPD datasets have DOIs in Harvard Dataverse; remaining inputs and outputs have DOIs in Zenodo, all accessible via the project GitHub website. The Supporting Information provides methods, equations, assumptions, and additional results.

6. Author contribution statement

A.M.G. contributed to conceptualization, data collection, data analysis, methodology, visualization, computer code development and manuscript development (drafting, reviewing, and editing).

C.J. contributed to manuscript development (reviewing, and editing).

G.M. contributed to funding acquisition, manuscript development (reviewing, and editing).

R.B.H. contributed to conceptualization, funding acquisition, manuscript development (reviewing, and editing).

R.S.D.C. contributed to conceptualization, funding acquisition, data analysis, visualization, computer code development, manuscript development (drafting, reviewing, and editing), management and supervision.

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