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Policy Analysis

Total Social Costs and Benefits of Long-Distance Hydropower Transmission

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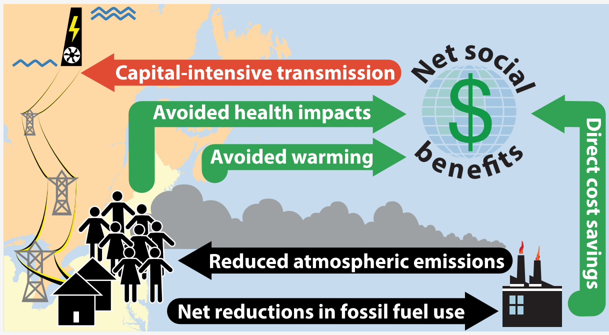
ABSTRACT: Increasing amounts of hydropower are being exported from Canada to the northern United States. Recently proposed projects would increase transmission capacity to U.S. population centers without increasing generation. This avoids generation-side impacts from hydroelectric development and introduces power to the U.S. energy mix that is dispatchable, unlike wind and solar, with greenhouse gas emissions generally lower than those of fossil fuels. There is, however, a lack of analysis comparing high upfront capital costs to social benefits and controversy over valuation of social costs of hydropower from existing generation given the negligible marginal cost of production. This analysis evaluates direct and indirect costs in comparison to alternatives for a 1250 MW transmission line from Canada to New York City currently under development to replace the recent loss of ~15 TWh year^{-1} of nuclear generation. For the case study considered, we find that long-distance transmission avoids \$13.2 billion (\$12.1−14.4 billion) in total social costs by 2050. This includes \$4.2 billion (\$3.4−5.1 billion) from premature mortality in disproportionately Hispanic and African American or Black counties (roughly 306 avoided deaths). In an extensive sensitivity analysis, results are robust to all modeling choices other than the cost assigned to hydropower: the nominal dollar value of hydropower imports (payments from buyer to seller) commonly used in cost−benefit analysis leads to substantial underestimates of net benefits from transmission projects. The opportunity cost of these imports (e.g., environmental benefits foregone in alternative export markets) is a better metric for cost but is difficult to estimate.



KEYWORDS: *renewable energy, hydropower, decarbonization, environmental impact assessment, cost−benefit analysis*

1. INTRODUCTION

Electrical generation is a significant source of greenhouse gas (GHG) emissions worldwide. In the United States, electrical generation accounted for 25% of GHG emissions by carbon dioxide equivalents (CO_2 eq) in 2019.[1] Decarbonization of the electrical sector is widely considered one of the most achievable components of a global economy that realizes net-zero GHG emissions by 2050 and hence constrains global temperatures to within 1.5 °C of preindustrial averages.[2,3] Recent analysis for the United States suggests this will require a combination of roughly \$2 trillion of capital investments in the 2020s and 2030s and some combination of significant policy actions such as carbon taxes, energy efficiency standards, and/or increased electrification.[3]

Canadian hydropower is an increasingly attractive electricity source in northern U.S. markets. Hydropower has GHG emissions and marginal costs substantially lower than those of fossil fuel alternatives.[4,5] Additionally, it is dispatchable (non-intermittent), unlike wind and solar. Net annual electricity exports from Canada to the United States have therefore been increasing by an average of 1.3 TWh since 2007, reaching 47 TWh in 2019, compared to total U.S. renewables generation of 728 TWh.[6,7] In New England, hydropower imports from Canada accounted for 21% of electricity supplied to consumers in 2020, up from 8% in 2010.[8,9]

Historically, hydropower imports have been purchased on the short-term spot market and distributed on existing U.S. infrastructure. For example, between 2014 and 2019, 90% of gross exports from Quebec, the largest producer and exporter of hydropower in Canada, were settled on the short-term spot market. Specifically, exports on long-term contracts totaled 19 415 GWh[10−15] compared to 195 400 GWh in total[15,16] for the same period. Recently, however, U.S. utilities have been negotiating long-term contracts tied to large transborder transmission projects independent of new generation infrastructure. For example, in 2021, construction began on the New England Clean Energy Connect (NECEC), a \$950 million, 1200 MW transmission line from Quebec through Maine, developed to provide 9.5 TWh year^{-1} to Massachusetts

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over a period of 20 years.[17,18] The Champlain Hudson Power Express (CHPE) is a planned >$3 billion, 339 mile, 1250 MW, 10.4 TWh year^{-1} transmission line from Quebec to New York City, designed to bypass bottlenecks in northern New York state.[19−21]

There has been disagreement over the net value of long-distance hydropower transmission projects. Developers tend to express benefits in terms of expected ratepayer savings, jobs created, and enhanced economic output.[19,20,22] These are calculated using proprietary economic input−output models, so the methodology and results are not independently verifiable. Generation-side direct and environmental costs are commonly neglected because transmission projects are not tied to development of new generating capacity.[23,24] Conversely, opponents have underlined high capital costs of long-distance transmission infrastructure and the possibility that it could divert hydropower from other markets and/or stimulate new generation capacity.[25−27]

Recent modeling work has indicated that build-out of U.S. wind and solar, supplemented by Canadian hydropower in times of low wind and solar output, would minimize direct costs associated with long-term decarbonization of the northeastern United States and eastern Canada.[28,29] However, that work does not explicitly consider environmental and health impacts such as changes in air pollution and does not account for intraregional transmission constraints that would necessitate large investments in stateside transmission infrastructure. A large literature characterizes the environmental and health impacts of new hydroelectric reservoir construction.[30−33] However, the impacts of decisions involving allocation of power supply from previously developed generating capacity are understudied.

Existing cost−benefit analysis for long-distance hydropower transmission is conducted from the perspective of individual stakeholders (e.g., prospective buyers of electricity).[34] However, these costs represent transactions between parties (e.g., negotiated price per megawatthour distributed), which do not reflect total costs to society, or whether these costs are exceeded by benefits distributed over society as a whole (i.e., Kaldor−Hicks efficiency).[35] Those "costs" are not easily compared to countervailing benefits, such as displaced greenhouse gases, which accrue globally. Existing analyses also do not assess several significant sources of uncertainty in total social costs, for example, the opportunity cost reflecting the possibility for transmission infrastructure to divert exports from other markets.[26] Overall, there is a lack of analysis characterizing how the apparent cost-effectiveness of long-distance hydropower projects can be affected by modeling uncertainties and alternative conceptions of the cost of power.

This work uses as a case study the CHPE transmission project mentioned above. CHPE is being planned in the context of the closure in 2020−2021 of Unit 2 (1020 MW) and Unit 3 (1040 MW) of Indian Point Energy Center, a nuclear power plant roughly 40 miles north of New York City. Contemporaneously with the closure of Indian Point, three natural gas plants have been developed to ensure that electrical demand continues to be met.[36] CHPE may offset the additional fossil fuel generation introduced following the closure of Indian Point but has been controversial due to relatively high capital costs and uncertainty over whether it will lead to higher levels of fossil fuel generation elsewhere.

We synthesize publicly available energy, environmental, and economic data to characterize the costs and benefits of CHPE relative to available alternatives. We consider direct costs (construction, fixed, and variable operational costs) and environmental costs (GHG and local air pollution) over the period of 2022−2050 for scenarios with and without CHPE. Costs are evaluated within a probabilistic model that tracks uncertainties in parameter values and controls for uncertainties that are correlated across scenarios. This framework improves the precision of estimates for differences in costs between scenarios, which are most relevant for decision making.[37] This work reports total costs using publicly available data and transparent modeling assumptions, providing a template that can be updated in the future or applied elsewhere.

2. METHODS

2.1. Scenario Development. Between April and October 2020, we engaged expert stakeholders in an iterative scenario development process centered on the construction of CHPE, which emerged as scenario B in this analysis. These stakeholders included NYSERDA, the New York City Mayor's Office, Hydro-Québec, and the Ministry of International Relations and La Francophonie (MRIF) of the Government of Quebec. This process consisted of developing plausible energy transition scenarios for New York City over the period of 2020−2050 and developing comparisons in terms of end points perceived by stakeholders to be driving decision making. Those activities culminated in the publication of a policy report in October 2020 and were supported by the MRIF.[38] No stakeholder had any role in selecting methodology, provided data that were not already publicly available, or attempted to influence publication or nonpublication of any finding or interpretation.

We evaluate the benefits of long-distance hydropower transmission by tabulating total costs (i.e., costs to society) under the alternative, hypothetical scenarios summarized in Figure 1. These six scenarios are developed for the New York

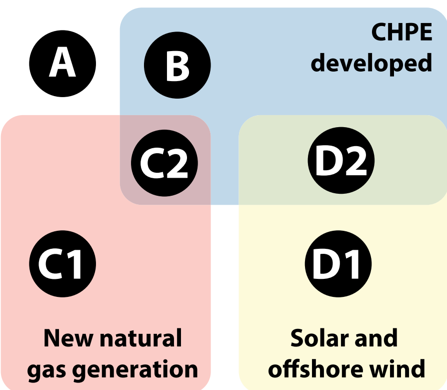

Figure 1. Euler diagram showing how scenarios of analysis (black circles) represent different combinations of infrastructure interventions (shaded rectangles) after the closure of IPEC. Scenario A assumes no infrastructure development.

City area where the staged closure in April 2020 to April 2021 of Indian Point Energy Center has removed roughly 15 TWh per year of nuclear power from the energy mix compared to 2019 and previous years. Scenario A represents this status quo. This is an absolute lower bound of costs because it does not account for any investments in new generation (e.g., to replace retired infrastructure). Loss of generation from Indian Point has thus far been offset by increased levels of fossil fuel

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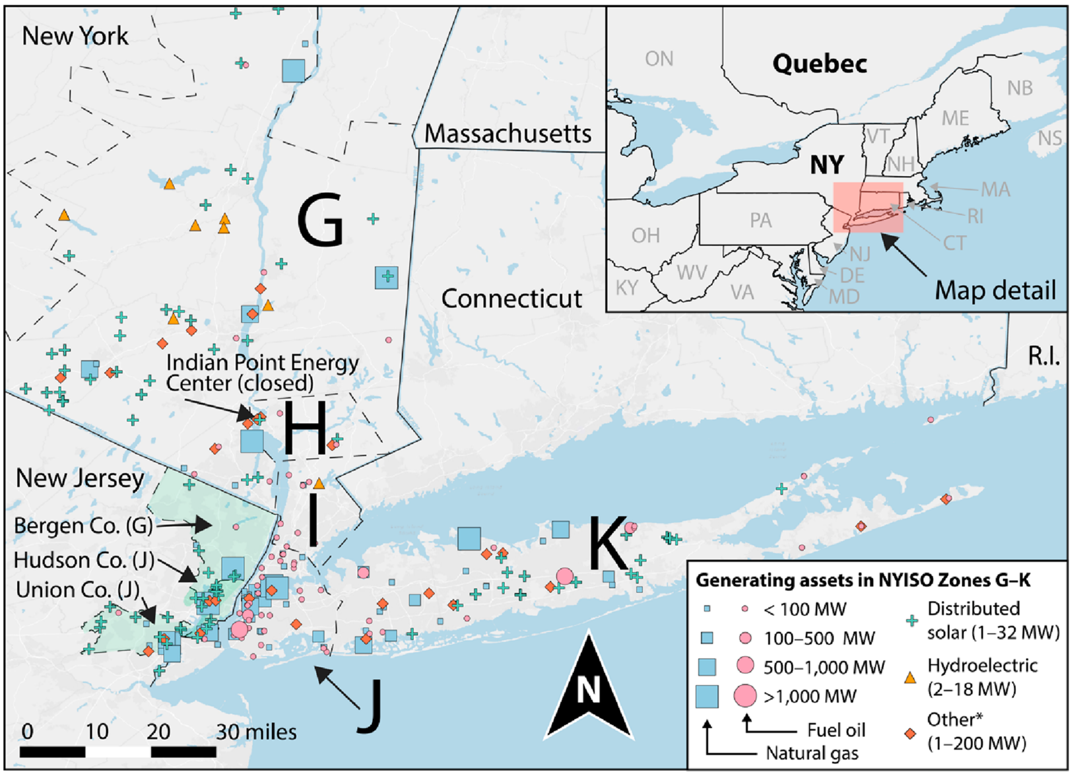

Figure 2. Map of generating assets reporting to eGRID located in NYISO zones G−K. The map includes assets in three counties in New Jersey that are reported by NYISO as contributing to zones G and J (green shading). Hatched lines delineate NYISO zones and relevant NJ counties. Solid lines delineate state and provincial borders. Natural gas includes dual fuel. *"Other" does not include closed facilities such as Indian Point Energy Center, whose location is indicated on the map with an arrow. Base map from Esri et al.[40]

generation. Upon comparison of the fuel mix data for the 11 months prior to the decommissioning of Indian Point (May 1, 2019, to March 31, 2020) to the equivalent period afterward (May 1, 2021, to March 31, 2022), statewide nuclear output declined by 16.5 TWh, and fossil fuel generation increased by 10.0 TWh, even as total generation declined by 7.8 TWh (∼7% of total generation in the latter period). This comparison excludes the months of April because they were affected by closure of Unit 2 (April 2020) and Unit 3 (April 2021). Table S1 lists fuel mix data for periods before and after closure of Indian Point from NYISO (2021). Increases in fossil fuel use are explained by the increased output of natural-gas-only facilities (60% of the total increase) and dual-fuel (natural gas and fuel oil) facilities. In 2020, 99% of dual-fuel generation in New York was from natural gas and 1% was from fuel oil.[39] Therefore, in scenario A, we consider that Indian Point output has been replaced by natural gas (99.6%) and fuel oil (0.4%) generation. This is a lower estimate for the contribution of fuel oil; the closure of Indian Point decreased the dispatchable capacity and likely increased the need for oil peaker plants compared to the time period captured by eGRID[40] data.

We model generation that replaces Indian Point using energy using a basic dispatch curve methodology.[41,42] Replacement energy is drawn from facilities in decreasing order of highest real annual capacity factors in 2020 according to NYISO.[43] Power is drawn from the most utilized generator up to the point where its capacity factor would equal 100%, and then additional power is drawn from the next most highly utilized generator and so on. This dispatch curve methodology reflects the fact that facilities with lower marginal costs are more highly utilized and are likely to be the first to be dispatched in response to a loss of other generation capacity. The contribution of oil peakers to the fuel mix pre- and postclosure of Indian Point is known and described above; therefore, for this analysis, we do not need greater temporal resolution to capture the contribution of oil peakers. This method is more approximate than a dispatch methodology based on hourly cost minimization subject to generator ramping speeds, minimum outputs, etc. However, we expect the uncertainties inherent in the annual dispatch method to be correlated across scenarios, meaning these uncertainties are less significant in the context of cross-scenario differences, which are the focus of this analysis.[37]

We track the physical location of the generating capacity compensating for the closure of Indian Point to model location-specific air quality impacts (section 2.4). We confine this analysis to the downstate region (NYISO zones G−K) due to transmission bottlenecks in the New York power grid that constrain downstate utilization of upstate generation.[44] We justify this assumption in a sensitivity analysis (section 3.4). Existing downstate generation facilities are mapped in Figure 2.

CHPE can contribute 10.4 TWh of hydropower from Canada per year to the energy mix if developed.[21] Scenario B represents the status quo, but with CHPE offsetting 10.4 TWh per year of local generation. For CHPE, we consider costs to be borne in 2022 and the first power to be delivered at the end of 2025.[45] The balance of generation is supplied by existing capacity as in scenario A.

We further consider the possibility that new natural gas generation is developed to offset the closure of Indian Point both alone (scenario C1) and in conjunction with CHPE (scenario C2). This scenario is included to contextualize the

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direct and indirect costs in other scenarios. For new natural gas generation, we consider capital costs to be borne in 2022 and the first power to be delivered at the end of 2030. This is based on the 8−10-year interval between permitting and power generation of recently developed natural gas plants in New York State (e.g., eight years for the 1176 MW Cricket Valley Energy Center and 10 years for the 770 MW CPV Valley Energy Center).[43,46,47] The 2019 Climate Leadership and Community Protection Act ("Climate Act") commits New York to decarbonize its electricity sector by 2040.[48] Therefore, we do not consider the construction of new natural gas generation likely.

The Climate Act sets a target of 6 GW of solar capacity by 2025 and 9 GW of offshore wind capacity by 2035. Tables S2 and S3 list the existing capacity and build-out rates, respectively, for battery storage, wind, and distributed and utility solar projects. Historic build-out rates suggest that New York is on track to meet its solar goal by 2024 with 42% of capacity located in the downstate region (NYISO zones G−K). The offshore wind goal will likely be met by 2029 (100% downstate). Using existing capacity factors, future build-out of wind and solar may add roughly 38 TWh of renewable capacity per year, eventually exceeding lost generation from Indian Point. Capacity factors are compiled for all generation technologies considered in Table S4.

We consider downstate renewables build-out both without CHPE (scenario D1) and with CHPE (scenario D2). Costs are assumed to be borne in the same year as power delivery for distributed solar projects based on the six-month median project time reported by NYSERDA[48] with statewide build-out up to 6 GW ending in 2025. We assume that 42% of this capacity will be in the downstate region based on the distribution of already completed projects.[49] We consider a four-year lead time for wind projects based on recent projects in downstate New York, e.g., Copenhagen Wind Farm proposed in 2012 and Shoreham Solar Commons proposed in 2014, both of which came online in 2018.[43,50,51] Build-out lasts until 2035. During build-out, generation is supplied by existing capacity only, as in scenario A (scenario D1), or existing capacity offset by CHPE (scenario D2). In a sensitivity analysis (section 3.4), we explore the impact on net costs of considering CHPE to offset the renewable generation goals of New York State. Given the legislative commitment of New York State to electrical decarbonization and the documented pace in achieving these goals, we assume that the construction of CHPE in scenario D2 does not slow or displace development of local renewables capacity. This analysis thus does not consider second-order economic effects such as potential displacement of renewables build-out by hydropower imports.

2.2. Direct Costs. For all scenarios described above, we consider total direct economic costs. These are monetary expenditures required to produce and distribute electricity and include upfront capital, fixed recurring, and variable (i.e., marginal) recurring costs borne by society as a whole. These costs can be spread across stakeholders by different means (e.g., government subsidies, recovery of costs from ratepayers, etc.). To calculate total social costs, we therefore do not include monetary payments between parties for wholesale or retail procurement or sales. This differs from (for example) cost analyses for procurements that include contractually negotiated wholesale prices different from true marginal generation costs.[17,34] All costs are reported in 2019-USD, and future costs are discounted at 2% per year. This discount rate is chosen for consistency with the GHG emissions valuation guidelines recently adopted by New York State.[52] Upfront capital costs are assumed to be borne as described in section 2.1.

Fixed operation and maintenance (O&M) costs are also considered for new generation capacity (scenarios B, C1, C2, D1, and D2). These are recurring costs paid every year of operational generating capacity. The first operational year for each new generating alternative is described in section 2.1. We do not consider fixed O&M costs for scenario A (status quo) because those costs are borne regardless of decisions about how to replace generating capacity from Indian Point.

Fuel costs and other variable O&M costs are calculated for all scenarios, including scenario A (status quo). Power delivered to replace the output of Indian Point using existing generating capacity (scenario A) incurs costs beyond what would otherwise be incurred (i.e., fixed costs) and must therefore be calculated. These costs are proportional to the power delivered and vary according to fuel source.

Upfront capital costs and fixed and variable O&M costs are listed in Table S4. Fuel costs are listed in Table S5. Where possible, we consider the range of possible values by pooling available estimates into a uniform distribution, which we sample using Monte Carlo simulations described in section 2.6.

New York State previously carried out a cost−benefit analysis of long-distance hydropower transmission and considered direct costs of $13.5 billion, inclusive of capital investments and 2¢ per kWh for power delivered (i.e., monetary transfer from buyer to seller). The price paid for power delivered is the outcome of negotiations that reflect both buyer's and seller's assessments of each other's alternatives. This is a direct cost from the perspective of the buyer but is a wash from the perspective of society as a whole because the buyer's loss is the seller's gain. It is likely to be a poor representation of true social costs, because it reflects many factors beyond the marginal cost of generation.

It is, however, possible that power distributed to new markets via long-distance transmission infrastructure could divert exports to other markets; this in turn may increase fossil fuel generation in those markets that would otherwise use hydropower, imposing social costs that way. This is a form of opportunity cost. Therefore, in this analysis, we consider direct costs associated with capital investment in the range of $2.96−4.45 billion, corresponding to available estimates (Table S5) and supplement this with a detailed analysis of how different levels of power diversion and cost of power to the buyer may affect apparent cost-effectiveness (section 2.5).

2.3. Greenhouse Gas Emissions and Costs. For all scenarios, we calculate total emissions of CO_2, CH_4, and N_2O. For existing generators with nameplate capacity of >100 MW, GHG emissions factors are derived from data reported to eGRID.[39] In 2020, 94% of fossil fuel generation in New York State derived from facilities with installed capacities of ≥100 MW.[43] For the remaining generators and for scenarios with new construction, generic emissions factors from the U.S. Environmental Protection Agency (EPA)[53] are used (Table S5).

We economically value GHG emissions using the methodology promulgated by New York State, which assumes a discount rate of 2%. Recommended costs for 2021 emissions (converted to 2019-USD) are $121/t of CO_2, $2732/t of CH_4, and $41 956/t of N_2O. Costs for future emissions climb to

Table 1. Summary of Externally Derived Parameters

description	probabilistic treatment	calculation method or data location	location of detailed methods
capacity factors for existing generators	deterministic	NYISO database[43]	section 2.1
capacity factors for new generators	uniform distributions from available estimates	Table S5	section 2.1
direct costs (upfront capital, fixed O&M and variable O&M)	uniform distributions from available estimates	Table S4	section 2.2
direct fuel costs	uniform distributions from available estimates	Table S5	section 2.2
greenhouse gas (CO_2, CH_4, and N_2O) emission factors	deterministic	eGRID database[39] for ≥100 MW[a] generators and Table S5 for other generators	section 2.3
ambient air pollutant (SO_x, NO_x, CO, and TPM[b]) emission factors	uniform distributions from available estimates[c]	eGRID database[39] for ≥100 MW[a] generators and Table S6 for other generators	section 2.4
stack height of existing generators	deterministic	EIA Form 860[60] for ≥100 MW[a] generators	section 2.4
economic valuation of ambient air pollutant (SO_x, NO_x, PM_{10}, and $PM_{2.5}$) emissions	deterministic valuations based on stack height for ≥100 MW generators;[a] uniform distributions for other generators	Table S7 summarizes the output of the AP3 model for every relevant New York, New Jersey, and Pennsylvania county assuming \$9.2 million per avoided fatality	section 2.4
economic valuation of CO emissions	uniform distributions from available estimates	Table S8	section 2.4

[a]Accounts for 94% of fossil fuel generation. [b]Fractions of TPM as $PM_{2.5}$ and PM_{10} calculated as described in section 2.4. [c]Certain fuel/pollutant combinations have only point estimates available.

\$167/t of CO_2, \$4684/t of CH_4, and \$64 399/t of N_2O by 2050, respectively.[54,55]

Scenario B involves the construction of long-distance transmission infrastructure to power downstate New York with existing generation capacity. Because this project uses existing reservoirs and generation infrastructure, we do not attribute greenhouse gas emissions to this scenario. This effectively corresponds to the "consequentialist" tradition in life cycle assessment, in which impacts are considered only when there is a relevant causal relationship.[56]

2.4. Ambient Air Pollutants. We calculate total emissions of SO_x, NO_x, CO, and particulate matter (PM) for all scenarios. For existing generators with nameplate capacity of >100 MW (accounting for 94% of fossil fuel generation in 2020), emissions factors for SO_x and NO_x are derived from data reported to eGRID.[39] For other generators and for new construction, we use the latest technology-specific information from the U.S. EPA.[57] These emissions factors are listed in Table S6.

We evaluate the economic impact of SO_x, NO_x, and PM emissions using county-specific marginal emission valuations from the APEEP (AP3) model.[58] This model calculates premature mortality from increased exposures to these airborne contaminants emitted from stacks of different heights. For the purposes of economic valuation, we retain a valuation of \$9.2 million per avoided mortality, corresponding to U.S. EPA's current policy guidance (\$7.4 million in 2006-USD converted to 2019-USD).[59] We matched each fossil fuel generator with installed capacity of ≥100 MW in the NYISO[43] database to stack height information from EIA Form 860.[60] Among these generators, we found matches in EIA Form 860 for generators representing 94% of fossil fuel output from ≥100 MW generators (i.e., 88% of all fossil fuel generation in New York State). Generators with known stack heights were assigned deterministic marginal damage values for each contaminant from the AP3 model. For smaller generators and generators for which we could not find a match in EIA data, we pooled damages across stack heights and considered damages as an uncertain value with a uniform distribution in the Monte Carlo analysis (section 2.6).

The APEEP (AP3) model calculates damages for $PM_{2.5}$, but EPA emissions inventories report total particulate matter (TPM). We assume that $PM_{2.5}$ accounts for 100% of TPM emissions from natural gas,[61] 42−96% (uniform distribution) of TPM emitted by fuel oil combustion,[62] and 21−44% (uniform distribution) of TPM emitted by coal combustion.[63] AP3 does not include valuations for PM_{10}. We consider PM_{10} valuations from an earlier version of the APEEP model,[64] though these are substantially smaller than $PM_{2.5}$ valuations and have little impact on the analysis. County-specific emission valuations are listed in Table S7 (converted to 2019-USD). APEEP does not provide valuations for CO emissions. For CO, we pool estimates available in the literature into a range of \$2−1982 t^{-1} (2019-USD) for every county. We consider a uniform distribution. Valuations found in the literature are compiled in Table S8.

We did not identify sources of data that would allow us to further refine our estimates for site-specific emissions factors or valuations or information on the structure of variance that would justify probability distributions other than the uniform distribution. Economic valuations for air pollutant exposures are dominated by exposures to SO_x, NO_x, and PM from AP3. However, damages are reported deterministically for each stack height/county combination and do not reflect epidemiologic uncertainties. Uncertainties reported in this analysis derive primarily from uncertainties in other model variables such as stack height and emissions from facilities with missing data. However, as discussed in the Results, avoided damages from ambient pollutants are a small fraction of total economic impacts under all modeling assumptions.

2.5. Cost of Hydropower. While the marginal cost of hydroelectric generation is negligible, the contractually negotiated per megawatthour price of electricity is a significant fraction of total costs associated with infrastructure development and long-term purchase agreements (i.e., from the perspective of the buyer).[17,34] The likely distribution of costs and benefits between contracting parties (e.g., wholesale prices and retail prices) is outside the scope of this study. However, the rate charged by the seller to the buyer is affected by the seller's opportunity cost, i.e., the revenue that could be earned if the power were committed to other markets.[17] This points to

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Table 2. Net Present Values of Costs (billions of 2019-USD) Associated with Replacing 15 TWh of Nuclear Generation per Year from Indian Point[a]

	scenario A (status quo)	scenario B (CHPE)	scenario C1 (NG)	scenario C2 (NG + CHPE)	scenario D1 (renewables)	scenario D2 (renewables + CHPE)
capital upfront	0 (0−0)	4.6 (3.8−5.5)	4.2 (2.4−6.5)	6.0 (4.9−7.1)	37.5 (29.6−45.4)	42.2 (34.2−50.0)
fixed O&M	0 (0−0)	0.1 (0.1−0.1)	0.8 (0.4−1.3)	0.3 (0.2−0.5)	17.4 (14.5−20.4)	17.5 (14.6−20.4)
variable O&M	1.7 (1.1−2.4)	0.8 (0.5−1)	1.7 (1.1−2.4)	0.8 (0.5−1.0)	−0.8 (−1.6 to −0.1)	−1.8 (−2.8 to −0.9)
battery storage	0 (0−0)	0 (0−0)	0 (0−0)	0 (0−0)	5.4 (5.0−5.8)	5.4 (5.0−5.8)
fuel	6.8 (6.3−7.3)	3.0 (2.8−3.2)	6.7 (6.2−7.2)	3.0 (2.8−3.2)	−2.9 (−5.4 to −0.5)	−6.9 (−9.5 to 4.5)
GHG emissions	18.9 (18.9−18.9)	7.9 (7.9−7.9)	17.4 (17.4−17.4)	7.6 (7.6−7.6)	−7.8 (−13.6 to−1.4)	−17.7 (−23.9 to −11.7)
air pollutants	4.2 (3.4−5.1)	2.0 (1.5−2.4)	3.4 (2.2−6.2)	1.6 (1.2−2.4)	−0.6 (−1.3 to 0.2)	−1.8 (−2.7 to −1.1)
sum	31.6 (30.3−33.0)	18.4 (17.3−19.5)	34.3 (31.6−37.7)	19.3 (18.0−20.7)	48.2 (34.6−62.0)	36.8 (22.7−50.5)

[a]Values are presented as means (90% prediction interval). Negative values are savings associated with build-out of >15 TWh of renewable generation per year. Abbreviations: NG, natural gas; CHPE, Champlain Hudson Power Express (long-distance hydropower transmission). Future costs discounted at 2% per year.

the possibility that new long-term contracts with new markets (as contemplated in scenario B) could reduce exports elsewhere, imposing social costs, for example, from generation that is needed to replace diverted exports. Indeed, in the context of New York, critics of CHPE have claimed that new long-term commitments to the New York City area will cause a reduction in exports to other markets, such as upstate New York, potentially reducing environmental benefits.[26]

In ref 38, we analyzed the possibility of CHPE causing reductions in exports to other markets, notably upstate New York. We concluded that these second-order effects are likely to be small given that (1) decarbonization commitments in main export markets exceed the recent contribution of hydropower imports, meaning demand for hydropower is likely to fall regardless of new export commitments to new markets, (2) historic reservoir levels (due to factors such as recent high spring thaws) are leading to nonrevenue spill events and low opportunity cost for exports, and (3) contractual negotiations can constrain adaptive behavior of exporters to ensure net environmental benefits. Since the publication of that analysis, a referendum in Maine has led to the suspension of development of the New England Clean Energy Connect (a planned 9.5 TWh year^{-1} transmission corridor to New England), further decreasing the opportunity cost of hydropower generated in Quebec.[65]

However, a low opportunity cost for long-distance hydropower transmission cannot be assumed in all contexts. Therefore, in the analysis presented here, we evaluate the sensitivity of total social costs and benefits to alternative assumptions about second-order impacts, notably, that imports may be diverted from other markets. We accomplish this by simulating a grid in upstate New York (i.e., NYSIO zones A−F) from which various fractions of hydropower exports are diverted using the dispatch curve methodology described above. We compare the effects of alternative assumptions here on overall net benefits from long-distance hydropower transmission with other sources of uncertainty. We compare plausible opportunity costs (corresponding to foregone opportunities for allocation of hydropower) to the "cost of power" (contractually negotiated price the buyer pays the seller) used in traditional cost−benefit analyses and evaluate the implications for analysis of total social costs.

2.6. Numerical Simulation and Presentation of Results. Table 1 summarizes externally derived parameters used in this analysis, noting the probabilistic or deterministic treatment of each, identifying where in the text the relevant methods are described and where numerical values are identified.

Where possible, multiple estimates for a given parameter value were pooled, and the parameter was simulated with a uniform distribution. The uniform distribution reflects the relatively small number of estimates on which the distributions are based and the lack of basis for prior beliefs about the relative likelihood of values within the pooled interval. Likewise, we have not assigned any correlations across parameter values (e.g., lower capacity factors associated with higher emissions factors). However, as we demonstrate in section 3.5, these uncertainties are much less important to overall cost-effectiveness than the assumed cost of hydropower.

Quantitative modeling of economic and environmental end points for all scenarios was carried out in the R programming language[66] within the RStudio integrated development environment (IDE).[67] Uncertainty was represented using Monte Carlo simulations (10 000 trials). Prediction intervals around differences (e.g., difference in net cost between two scenarios) account for the large correlations in uncertainties within each scenario. This produces information about comparative cost-effectiveness (e.g., differences in costs) with overall narrower uncertainties than individual scenarios (e.g., absolute magnitude of costs).[37]

As described in section 2.4, economic valuations for ambient air pollutant exposures from AP3 do not reflect epidemiologic uncertainties or variability in dose−response relationships so prediction intervals around those values may underestimate true uncertainty.

Figures were generated in R, QGIS,[68] and Adobe Illustrator[69] using the RColorBrewer package.[70,71] Maps were developed with basemap files from Esri et al.[40] and shapefiles from the U.S. Census Bureau[72] and NYPA.[73]

3. RESULTS

3.1. Overall Costs. Table 2 summarizes costs by scenario and cost type. We express costs in terms of the mean of 10 000 Monte Carlo simulations, with the 90% prediction interval in parentheses. Costs for scenarios A (status quo), B (long-distance hydropower transmission), C1 (new natural gas generation), and C2 (new natural gas transmission with long-distance hydropower transmission) are calculated assuming the 15 TWh year^{-1} from Indian Point is fully replaced. Scenarios D1 (build-out of wind and solar) and D2 (idem plus long-

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distance hydropower transmission) both consider the full planned build-out of renewables that will eventually provide 31.2 TWh year^{-1} (23.3−39.2 TWh year^{-1}) (section 2.1). Excess displaced fossil fuel generation reduces direct costs and environmental impacts relative to today's, represented as negative costs in Table 2. In a sensitivity analysis (section 3.4), we analyze how these valuations change under alternative assumptions described above.

Lowest total costs are achieved in scenario B (long-distance hydropower transmission via CHPE). While CHPE represents \$4.6 billion (\$3.8−5.5 billion) in upfront direct expenditures (Table S4), this is outweighed by savings in recurring direct expenditures (costs of fuel and variable O&M) and environmental impacts (GHG and air pollutant emissions). Compared to scenario A (status quo), CHPE reduces the net present value of future costs by \$13.2 billion (\$12.1−14.4 billion). For all energy transition scenarios, adding CHPE reduces total social costs (scenario B vs scenario A, scenario C2 vs scenario C1, and scenario D2 vs scenario D1) because benefits of avoided fossil fuel generation outweigh capital costs of CHPE. The benefit/cost ratio for CHPE is greater than for domestic renewables using the range of plausible values we considered (section 2.2). Benefits of CHPE include reduced premature mortality from air emissions in the densely populated area around New York City. This benefit is also one reason the cost-efficiency of CHPE is robust to assumptions about diversion of hydroelectric generation from upstate to downstate (section 3.5). We note that CHPE is a relatively expensive transmission project with unique design factors, such as underwater cables,[74] and therefore provides a conservative upper estimate of capital costs of long-distance transmission in general. For example, the mean estimate of CHPE upfront costs is \$4.6 billion (Table 2) or \$14.36 million per mile compared to a maximum estimate of \$5.35 million per mile proposed by the NREL JEDI model for transmission projects in New York.[75] Capital costs for NECEC are roughly \$6.6 million per mile.[18] These results include zero opportunity cost for hydropower distributed by CHPE. In section 3.5, we demonstrate how alternative conceptualizations of the opportunity cost can affect the apparent total net benefits.

As described in section 1, scenario B (CHPE only) assumes that the difference between former Indian Point output and the power delivered by CHPE (roughly 4.6 TWh year^{-1}) is replaced by legacy generation (mostly natural gas), while in scenario C2, this difference is replaced by new gas construction. Therefore, scenario C2 has higher capital costs than scenario B but almost the same marginal direct costs (variable O&M and fuel) and environmental costs. However, the latter are slightly lower in scenario C2 than in scenario B due to the increased efficiency of new facilities. Similarly, variable costs and environmental impacts in scenario A (status quo) are close to those in scenario C (replacement of the entirety of the Indian Point output with new natural gas generation).

Build-out of wind and solar (scenarios D1 and D2) over the period of 2022−2035 eventually provides 31.2 TWh year^{-1} (23.3−39.2 TWh year^{-1}) of generation (using the range of possible capacity factors listed in Table S4). Renewables build-out alone (scenario D1) or in conjunction with CHPE (scenario D2) results in capital costs that are higher than those of other scenarios due to the greater generation provided and the higher costs of wind and solar per MW installed capacity compared to other technologies. These large capital costs are offset by savings in recurring costs and environmental impacts (GHG and air pollutant emissions). For example, even though scenario D1 (renewables only) represents \$37.5 (\$29.6−45.4 billion) in capital costs, net costs are only \$16.6 billion (\$2.9−30.4 billion) greater than those of scenario A (status quo). The wide uncertainties in this estimate are associated with the wide range of possible upfront costs for future renewables build-out (SI Table S4) and the impact on GHG emissions from existing installed capacity. The latter uncertainty derives from a relatively wide range of possible future capacity factors for installed wind generation, with uncertainties in total benefits compounding over time.

3.2. Greenhouse Gas Emissions. The cost-effectiveness of renewables build-out (scenarios D1 and D2) and long-distance hydropower transmission (scenarios B, C2, and D2) can primarily be attributed to reductions in GHG emissions. Table 2 reports the economic value of GHG emissions for different scenarios to compensate for the loss of 15 TWh year^{-1} from Indian Point over the period of 2022−2050 actualized to 2022 and reported in 2019-USD. Scenarios D1 and D2 are associated with negative costs because wind and solar build-out more than replaces lost generation from Indian Point, although this is associated with substantial uncertainties.

Figure 3 plots cumulative GHG emissions for all scenarios evaluated in CO_2 equivalents [CO_2 (eq)]. Without the development of new generation capacity, we estimate that

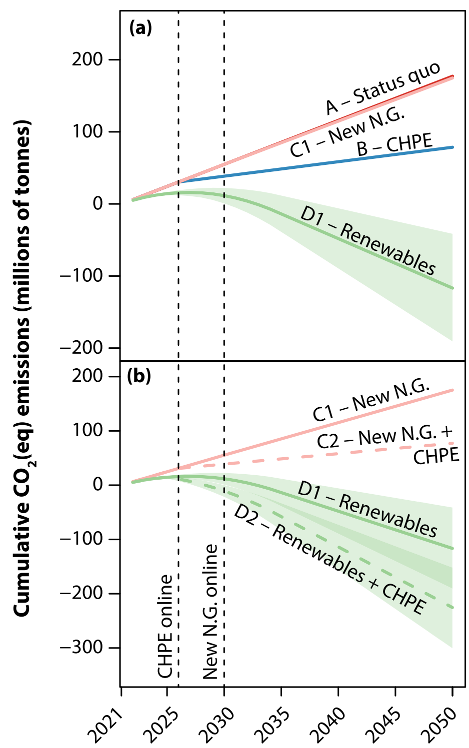

Figure 3. Cumulative GHG emissions in CO_2 equivalents for scenarios to replace 15 TWh year^{-1} formerly supplied by Indian Point Energy Center. Renewables build-out (scenarios D1 and D2) reflects New York State's goal of 3000 MW (solar) and 9000 MW (offshore wind), likely to provide output of 31.2 TWh year^{-1}, thus replacing Indian Point plus further fossil fuel generation. Long-distance hydropower transmission by CHPE (scenario B) is compared to other scenarios without CHPE in panel a. New natural gas and wind and solar build-out are both plotted with and without CHPE in panel b.

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Table 3. Total Emissions of Air Pollutants (tonnes per year) Associated with Replacing 15 TWh of Nuclear Generation per Year from Indian Point[a]

	scenario A (status quo)	scenario B (CHPE)	scenario C1 (NG)	scenario C2 (NG + CHPE)	scenario D1 (renewables)	scenario D2 (renewables + CHPE)
SO_x	36.9 (35.1−38.9)	16.5 (15.8−17.3)	30.0 (28.2−32.0)	13.4 (12.7−14.3)	−225.4 (−407.6 to 28.3)	−349.4 (−479.5 to 28.3)
NO_x	5104.8 (4276.6−5992.7)	2119.8 (1780.3−2483.9)	5269.9 (4393.7−6208.7)	2181.3 (1821.6−2566.9)	−1422.6 (−3743.9 to 3439.6)	−3021.8 (−5577.6 to 3439.6)
PM_{10}	1.1 (0.2−2.0)	0.4 (0.1−0.8)	0.3 (0.1−0.6)	0.2 (0.0−0.4)	−0.5 (−2.0 to 0.7)	−1.2 (−3.1 to 0.7)
$PM_{2.5}$	23.4 (21.0−26.1)	9.8 (8.8−10.9)	21.9 (20.1−23.8)	9.3 (8.5−10.2)	−12.0 (−31.5 to 16.0)	−26.2 (−47.7 to 16.0)
CO	3737 (3471.6−4025.3)	1559.8 (1449−1680.1)	3741.3 (3476.1−4029.3)	1561.2 (1450.5−1681.4)	−1916.9 (−5008.2 to 2547.0)	−4184.8 (−7585.8 to 2547)

[a]Values are presented as means (90% prediction interval). Values for each scenario are averages across the period of 2022−2050. Negative values are savings associated with build-out of >15 TWh of renewable generation per year. Abbreviations: NG, natural gas; CHPE, Champlain Hudson Power Express (long-distance hydropower transmission).

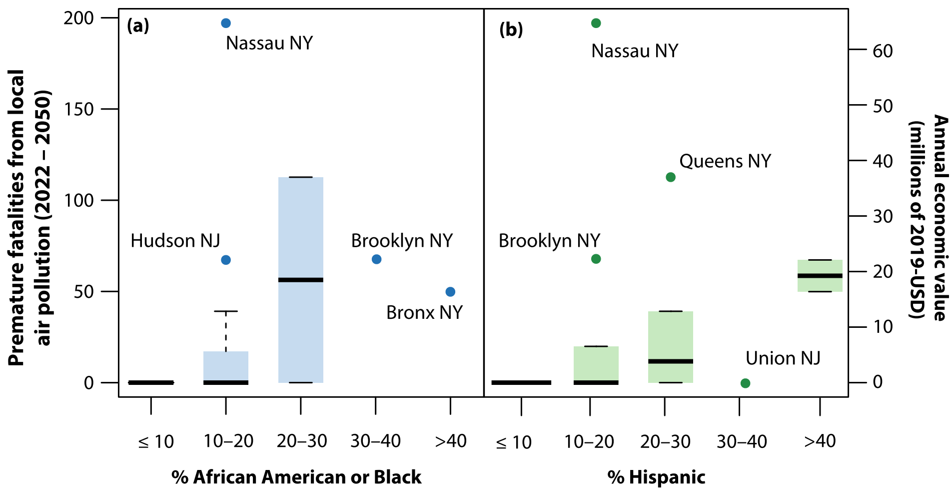

Figure 4. Premature mortality from air pollutants emitted by fossil fuel generators used to replace output from Indian Point [scenario A (status quo)] in 62 counties in New York, Hudson County and Union County, NJ, and Armstrong County, PA (part of NYISO zone J). Counties are grouped by African American or Black (a) and Hispanic (b) proportion of population. The left axis plots the number of premature fatalities over the period of 2022−2050, and the right axis plots the corresponding annual economic value. Both axes apply to panels a and b. There are 56 counties with no expected air quality impacts from the closure of Indian Point, of which 48 are ≤10% Hispanic and 47 are ≤10% African American or Black. For all scenarios, economic values associated with air impacts are listed in Table 2 (pooled across all pollutants), and pollutant-specific emissions are listed in Table 3 (pooled across all counties).

the closure of Indian Point will lead to 171.0 million t of CO_2 (eq) by 2050 [scenario A (status quo)]. New natural gas generation (scenario C) results in slightly lower emissions because of the improved efficiency of new generators with emissions reaching 168.7 million t of CO_2 (eq) by 2050. CHPE (scenario B) replaces roughly half of the capacity lost from the closure of Indian Point and thus substantially offsets the replacement fossil fuel generation; emissions by 2050 reach 72.6 million t of CO_2 (eq).

During build-out of wind and solar, existing fossil fuel generation capacity fills the demand formerly met by Indian Point (section 2.1). Assuming that state targets are respected (scenario D1), wind and solar output beyond the former generation of Indian Point will, cumulatively, outweigh extra GHG emissions generating during build-out by 2034 (90% prediction interval of 2031−2039). Upon addition of CHPE at the end of 2025 (scenario D2), these emissions are outweighed by 2029 (2028−2030). By 2050, the difference in cumulative emissions between status quo (scenario A) and build-out of wind and solar (scenario D1) is 267.5 million t (195.8−332.8 million t) of CO_2 (eq). Adding CHPE (scenario D2) averts a further 108.8 million t (103.7−112.8 million t) of CO_2 (eq) by 2050.

3.3. Air Quality Impacts. Increased fossil fuel generation associated with the loss of 15 TWh year^{-1} from Indian Point leads to increased air pollution. Similar to GHG emissions, the largest air quality impacts are realized in scenario A (status quo), which has an economic cost of \$4.2 billion (\$3.4−5.1 billion) over the period of 2021−2050. This corresponds to roughly 573 premature fatalities [90% confidence interval (CI) of 458−701 avoided mortalities]. Adding CHPE (scenario B) reduces this by \$2.2 billion (\$1.8−2.7 billion) or 306 (247−372) premature fatalities. Build-out of renewables past 15 TWh year^{-1} from Indian Point (scenario D1) displaces more fossil fuel generation than what was stimulated to replace Indian Point, which we represent as negative emissions with an economic value of −\$629.3 million (−\$170.4 million to −\$1.3 billion). Coupling CHPE with renewables build-out (scenario D2) increases this displacement by \$1.2 billion (\$909.6 million to \$1.5 billion). Table 2 displays the economic value of these emissions (pooled across all pollutants considered) for the period of 2022−2050 for each scenario evaluated. Table 3 presents average yearly emissions by pollutant pooled across all counties.

Excess air emissions associated with the transition from Indian Point are expected to accrue predominantly downstate

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Table 4. Net Present Values of Costs (billions of 2019-USD) Associated with Replacing 15 TWh of Nuclear Generation per Year from Indian Point[a]

	scenario A (status quo)	scenario B (CHPE)	scenario C1 (NG)	scenario C2 (NG + CHPE)	scenario D1 (renewables)	scenario D2 (renewables + CHPE)
main analysis (Table 1)	31.6 (30.3–33)	18.4 (17.3–19.5)	34.3 (31.6–37.7)	19.3 (18–20.7)	48.2 (34.6–62)	36.8 (22.7–50.5)
(i) downstate is zones H–J	35.0 (33.7–36.3)	19.6 (18.5–20.7)	37.6 (34.9–40.7)	20.8 (19.3–22.3)	49.7 (35.8–63.6)	42.2 (32.5–52.3)
(ii) downstate is zone J	34.1 (32.8–35.5)	19.1 (18.1–20.2)	37.1 (34–41.1)	20.2 (18.9–21.5)	49.4 (35.7–63.4)	42.2 (32.4–52.2)
(iii) discount rate of 3%	19.9 (18.7–21.1)	13.5 (12.5–14.6)	23.2 (20.7–26.2)	14.6 (13.4–15.9)	50.8 (40.3–61.5)	46.3 (35.7–56.9)
(iv) CHPE counts against renewables target	31.6 (30.3–33.0)	18.4 (17.3–19.5)	34.3 (31.6–37.7)	19.3 (18.0–20.7)	48.2 (34.6–62.0)	31.0 (22.3–39.6)

[a]Values are presented as means (90% prediction interval). Negative values are savings associated with build-out of >15 TWh of renewable generation per year. Abbreviations: NG, natural gas; CHPE, Champlain Hudson Power Express (long-distance hydropower transmission). Future costs discounted at 2% per year.

because of bottlenecks in New York State's electrical transmission infrastructure.[44] Downstate New York counties are more racially and ethnically diverse than New York state and the United States as a whole, so these groups are disproportionately impacted by increased air emissions. For example, downstate counties are 23% Black or African American and 10% Hispanic compared to 10% and 6%, respectively, in upstate counties. Counties with larger fractions of African American or Black or Hispanic residents are generally associated with higher expected impacts from air pollution (Figure 4). The major exception is Nassau County, which is likely to have the largest air quality impacts (~$64.5 million per year in scenario A) given its substantial generating assets (1287.4 MW natural gas with 24% utilization in 2020)[43] but which is only 14% African American or Black and 17% Hispanic.[76]

3.4. Sensitivity Analysis. Our findings are robust to substantial changes in underlying modeling assumptions. Here, we present the net present economic value of the scenarios we evaluated under alternative assumptions: (i) if the generation formerly supplied by Indian Point were borne in a narrower region around New York City, i.e., NYISO zones H–J only (instead of zones G–K), (ii) idem but considering NYISO zone J only, (iii) if we consider a discount rate of 3% (instead of 2%), and (iv) if generation from CHPE is subtracted from New York State's wind and solar build-out goals. Table 4 presents the total cost of all scenarios under these re-analyses in comparison with the main analysis (sum row of Table 2). Direct and indirect cost categories (all rows in Table 2) are retabulated for re-analyses i–iv in Tables S9–S12, respectively.

Re-analysis iii assumes a discount rate of 3% and provides the lowest estimates for benefits from long-distance hydropower transmission because benefits from future displaced GHG emissions are more highly discounted. Three percent is the highest discount rate for which New York State calculates a social cost of carbon.[54] The main analysis retains a discount rate of 2% based on the recommended default value for economic analyses (NYS DEC 2021). For example, the value of CHPE (scenario B) reduces total costs compared to no action (scenario A) by a minimum of $6.4 billion ($5.3–7.5 billion) under re-analysis iii compared to $14.9 billion ($13.8–16.1 billion) in the main analysis.

Other re-analyses have either no effect or a positive effect on the cost-effectiveness of long-distance hydropower transmission in comparison to alternative scenarios. Re-analyses i and ii narrow the range of generating capacity that is assumed to compensate for the closure of Indian Point (zones H–J and zone H, respectively). Because those generators are moderately less efficient than in the wider range of zones considered in the main analysis (zones G–K), benefits associated with displacing that generation are greater. Greatest differences are observed in the economic valuation of avoided mortality from atmospheric emissions (given that NYISO zones farther from New York City are less densely populated), but these differences are not great enough to change overall cost-effectiveness. We did not explicitly model potential impacts on the PJM interconnection, covering most of the mid-Atlantic region and trading power with downstate NYISO control zones. However, we would expect these impacts to be smaller than those considered in sensitivity analyses i and ii given the substantially smaller capacities and flows between the NYC area and PJM than between the NYC area and other NYISO zones.[77]

Re-analysis iv provides an upper bound of the economic benefits of coupling long-distance hydropower transmission to wind and solar build-out by assuming long-distance hydropower transmission reduces the amount of wind and solar (which have higher capital costs) that is needed. Total benefits of coupling long-distance hydropower transmission to wind and solar build-out (the difference between scenarios D2 and D1) increase from $11.5 billion ($10.2–12.7 billion) in the main analysis to $17.3 billion ($12.1–22.4 billion) in re-analysis iv.

This analysis has not considered impacts associated with activities that occur across all scenarios (e.g., maintenance of existing generators), and therefore, uncertainty of valuations for each scenario is greater than uncertainty for differences between scenarios. The latter was our focus to maximize the utility of this analysis for decision support.[37] For example, in all scenarios, we neglected greenhouse gas emissions associated with the construction and decommissioning phases of new technologies. Gargiulo et al.[78] reported life cycle GHG impacts from new transmission infrastructure ranging from 0.71 to 16.0 g of CO_2 (eq) kWh^{-1} [mean of 5.275 g of CO_2 (eq) kWh^{-1}] across four studies in different European settings. The mean value implies GHG impacts from CHPE of roughly 1.6 M t of CO_2 (eq) over the period of analysis, or roughly 2% of the GHG impacts calculated for scenario B.

3.5. Cost of Hydropower. This analysis has so far considered hydropower as essentially costless, given the small marginal costs of hydroelectric generation (similar to those of wind and solar generation). However, there has been debate about the possibility for new transmission infrastructure to divert generation from other markets, which would create costs, for example, by leading to increased fossil fuel generation in markets from which hydropower is diverted.[25,26] Furthermore, cost–benefit analyses from the perspective of the buyer (in this case study, New York State) typically consider a "cost of power" corresponding to a contractually negotiated payment from buyer to seller. However, this payment is a poor representation of social costs: payments between parties are a wash from the perspective of society as a whole (buyer's loss is seller's gain), and negotiated prices are untethered from marginal costs of generation and environmental externalities. Figure 5 plots how the apparent net benefits of long-distance hydropower transmission (scenario B) are affected by different assumptions for power diversion (bottom axis) and the "cost of power" considered by a buyer (top axis).

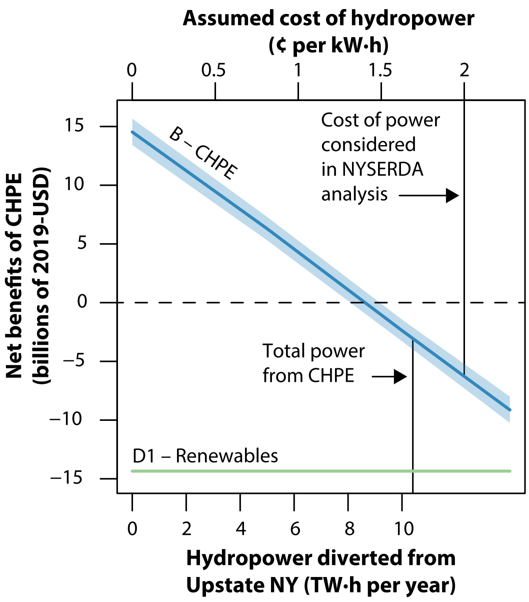

Figure 5. Net benefits of scenario B. Long-distance hydropower transmission via CHPE as a function of assumptions about the cost of hydropower used in traditional cost−benefit analyses, e.g., NYSERDA[35] (top axis), and as a function of assumptions made about diversion of hydropower exports from upstate New York (bottom axis). The shaded region is the 90% prediction interval for net benefits [total costs of scenario B subtracted from scenario A (status quo)]. The mean estimate for net benefits of renewables build-out (scenario D) is included for comparison. Values above the hatched line correspond to total social costs less than those of the status quo.

The bottom axis of Figure 5 presents increasing assumptions for the amount of power diverted from upstate to downstate New York. The net benefits of hydropower transmission to downstate (scenario B) decline as costs upstate increase. Upstate costs correspond to variable and fuel costs of the generators needed to compensate for diverted hydropower imports, and associated air pollution and greenhouse gas emissions. These are calculated using the dispatch curve methodology used elsewhere in this analysis. Net benefits of long-distance hydropower transmission (scenario B) are zero only when assuming 8.6 TWh year^{-1} (8.0−9.2 TWh year^{-1}) of a total possible value of 10.4 TWh year^{-1} is diverted from upstate. In the case study of New York City, long-distance hydropower transmission (scenario B) imposes lower total social costs than the status quo (status A) for all plausible values of power diversion from upstate New York. This diversion is believed to be low, as described in section 2.5. However, Figure 5 demonstrates that, in general, diversion from other markets could offset or reverse benefits of long-distance transmission projects.

The "cost of power" having an equivalent impact on net benefits of long-distance hydropower transmission as various levels of power diversion from other markets is plotted on the top axis of Figure 5. Cost analysis for New York State has considered 2¢ per kilowatthour.[34] This is lower than the prices of other recently negotiated contracts. For example, the recently negotiated New England Clean Energy Connect (long-distance transmission from Quebec to Massachusetts) included a cost of power starting at 5.1¢ per kilowatthour and climbing to 8.2¢ per kilowatthour over 20 years.[17] Subtracting these costs from net benefits of long-distance hydropower transmission (scenario B) reverses apparent cost-effectiveness even at low costs of power (e.g., 2¢ per kilowatthour). The negative effect on cost-effectiveness exceeds what is possible even assuming all power is diverted from other markets. However, even at high assumed costs of power, scenario B still presents greater net benefits than other likely scenarios, such as build-out of wind and solar without hydropower (e.g., compared to scenario D1 as shown in Figure 5). Indeed, the comparative cost-effectiveness to other feasible scenarios (e.g., comparing scenario B to scenario D1 as in Figure 5) is a more salient analysis than examining whether net benefits exceed a break-even point (∼1.3¢ per kilowatthour in Figure 5), because this break-even point is contingent on economic valuation methods that are subject to debate and uncertainty as discussed in section 3.4. This is particularly relevant for hydropower, whose opportunity costs may increase with the decommissioning of fossil fuel generators in Canada, assuming no increase in hydroelectric generation capacity.

3.6. Implications for Cost−Benefit Analysis of Long-Distance Transmission Projects. Long-distance transmission projects that use existing hydroelectric generation capacity to displace fossil fuel generation near population centers are increasingly proposed in the northeastern United States and elsewhere and pose novel problems for cost−benefit analysis. Notably, there has been debate about how to represent the cost of hydroelectric power that has a negligible marginal cost but which may have non-negligible opportunity cost. Cost−benefit analyses often use the nominal dollar value agreed contractually between buyer and seller to represent the cost of power. This analysis has shown that this practice is likely to lead to substantial underestimates of total net benefits in comparison to the opportunity cost, i.e., the next-best use of hydroelectric power. It is also inconsistent with the frame of reference retained for other benefits routinely factored into cost−benefit analyses, notably, the social cost of carbon, which considers damages globally.

The opportunity cost of hydropower imports, i.e., costs associated with hydropower that would have gone elsewhere if not for the construction of new infrastructure (bottom axis of Figure 5), is more consistent with the quantification of total social costs and benefits. However, in most cases, this is difficult to quantify because it requires simulation of a counterfactual regional grid to determine the next-best use of hydropower reflecting (1) the evolution of local and export markets (e.g., build-out of wind and solar in upstate New York resulting in declining export opportunities for Quebec) and (2) the likely future behavior of hydropower exporters. This behavior is in turn guided by forecasts for economic variables (e.g., retail/wholesale price of power in export markets), hydrologic variables (e.g., reservoir inputs from precipitation), and social variables (e.g., uptake of electricity-intensive technologies such as electric vehicles and cryptocurrency).[79]

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Forecasts and frameworks that guide developer decisions are not publicly disclosed, complicating the precise valuation of the opportunity cost. However, even upper estimates are likely to generate more realistic estimates of net benefits of long-distance transmission projects than the nominal cost to buyer.

We have represented the total costs of long-distance hydropower transmission and alternative energy futures as the product of uncertain and relatively widely distributed variables (in most cases, uniform distributions between minimum and maximum available estimates). In our analysis of the primary sources of uncertainty other than cost, discount rate, and geographical scope of grid to consider, none affected the direction of net benefits of long-distance hydropower transmission.

To the extent that long-distance projects displace fossil fuel generation in the proximity of densely populated urban centers, there are substantial environmental health and justice benefits. In the case of transmission to New York City, we have valued benefits from avoided premature mortality at \$2.2 billion (\$1.8−2.7 billion) by 2050, corresponding to 306 (247−372) avoided premature fatalities. Avoided mortality in the densely populated New York City region contributed to the overall cost-effectiveness of long-distance hydropower transmission even allowing for diversion of some fraction of exports from less densely populated upstate New York (Figure 5). In general, greater benefits accrue to counties with higher fractions of Black/African American and/or Hispanic residents. To the best of our knowledge, environmental justice benefits of these projects have not previously been evaluated.

Greenhouse gas emissions dominate costs related to the status quo (and benefits associated with displacing fossil fuel generation). This analysis has used current guidance from New York State, which itself is based on the widely used Interagency Working Group valuation for the social cost of carbon, which considers global damages (i.e., total costs to society, not just to New York State).[54] There are uncertainties in models underlying this policy advice, such as the extent to which development may reduce the sensitivity of developing countries to the effect of climate change, and disagreement over the range of impacts for which economic analysis is meaningful.[80,81] Any analysis of the benefits of long-distance hydropower transmission (or indeed any decarbonization pathway) is subject to revision based on changing consensus about how to value the social cost of carbon. This analysis has also retained a consequentialist perspective for valuing emissions, including only those that are causally linked to a policy decision (i.e., marginal emissions from generators that are fired or not based on decision making but not emissions that occur regardless of actions taken now).[56]

There are substantial undeveloped hydroelectric resources worldwide. For example, Canada produces roughly 400 of a total potential of 1000 TWh of hydropower per year.[82] While this analysis has focused on analysis of the allocation of hydropower from existing generators to new markets, it highlights many considerations important to new development, too. Notably, total social costs can be materially affected by the extent to which they can displace fossil fuel generation in densely populated urban areas on the other end of transmission grid bottlenecks, as in the case study evaluated here. Likewise, quantification of net benefits is sensitive to the methods retained to evaluate costs. To the extent that total social costs and benefits are considered, a careful distinction must be drawn between direct costs to one stakeholder and total costs to society.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.2c06221.

Tables of input parameters and supplementary results from the sensitivity analysis (PDF)

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Notes

The authors declare no competing financial interest.

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