Analysis of Environmental and Economic Impacts of Hydropower Imports for New York City through 2050

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Summary

Indian Point Energy Center (IPEC), a nuclear generating facility that has provided roughly 15 TW·h per year of low-emissions power to the New York City area, will close by 2021. There has been debate over the potential responses to the closure of IPEC which include the development of new generation and transmission infrastructure. This derives in part from difficulties in comparing direct and indirect costs and benefits and environmental and social impacts, which vary substantially across energy alternatives. In particular, the potential role of increased imports of hydropower from Canada to the New York City area has been controversial because of large upfront capital costs and uncertain benefits relative to alternatives such as increased build-out of Downstate New York offshore wind and solar.

This study identifies conceivable scenarios for responding to the closure of IPEC and uses publicly available data to quantify the plausible ranges of direct and indirect economic and environmental costs and benefits of each scenario over the period 2021–2050. To the extent possible, environmental impacts are paired with economic valuations to enable comprehensive cost-benefit analysis. Comprehensive uncertainty analysis includes the explicit consideration of key parameters as uncertain variables and an extensive sensitivity analysis in which the impact of modeling assumptions on overall results is assessed.

Plausible scenarios following the closure of IPEC are: (A) no action; (B) development of the Champlain-Hudson Power Express (CHPE), a direct transmission line between Quebec and the New York City area; (C1) development of new Downstate natural gas capacity; and (D1) continued buildout of Downstate offshore wind and solar generation facilities. Costs and benefits are evaluated for each, as well as for composite scenarios involving CHPE together with

new Downstate natural gas (C2) and continued build-out of Downstate offshore wind and solar (D2). Timelines and valuation of costs and benefits are carried out using publicly available historical data. We do not quantitatively consider potential difficulties related to the development of new natural gas capacity in light of the 2019 Climate Leadership and Community Protection Act (CLCPA). We also do not quantitatively consider potential reliability issues associated with buildout of solar and offshore wind.

The closure of IPEC, in the absence of new generating or transmission infrastructure (Scenario A, no action), is likely to lead to **direct economic costs of $8.0 billion (90% CI: $7.2–$8.8 billion) and indirect environmental impacts valued at $9.0 billion (90% CI: $8.9–$9.1 billion)** over the period 2021–2050, assuming a 3% discount rate.

Every other scenario considered (Scenarios B, C1, C2, D1, D2) reduces environmental and health impacts relative to no action. The net present value of these savings ranges from **$1.2 billion (90% CI: $1.2–$1.3 billion) in the case of new Downstate natural gas development (Scenario C1) to $7.4 billion (90% CI: $6.9–$7.6 billion) in the case of CHPE plus expansion of Downstate offshore wind and solar** over the period 2021–2050, assuming a 3% discount rate.

When direct costs and environmental costs are combined, **the scenarios calculated to be more cost-effective than no action (Scenario A) all involve development of CHPE** (Scenarios B and C2). This is primarily because the large benefit of avoided greenhouse gas (GHG) emissions comes earlier in the case of CHPE (as of 2025) than for other interventions.

Build-out of Downstate offshore wind and solar is likely to generate by far the largest indirect economic impacts (local expenditures and job creation) compared to construction of new natural gas or CHPE. However, Downstate offshore wind and solar also represent by far the largest up-front costs ($17.4 billion, 90% CI: $13.9–21.0 billion at 3% discount rate) to compensate for lost generation from IPEC. The comparative cost-effectiveness of build-out of Downstate offshore wind and solar is improved by simultaneous implementation of CHPE. For example, total direct and environmental costs associated with offshore wind and solar + CHPE (Scenario D2) total $21.8 billion (90% CI: $19.6–$24.0 billion) compared to $32.7 billion (90% CI: $28.3–$37.0 billion) for offshore wind and solar alone (Scenario D1), assuming a 3% discount rate over the period 2021–2050. This improved cost-effectiveness is due to upfront avoided GHG emissions while build-out of offshore wind and solar is occurring and because CHPE reduces the amount of renewables necessary to compensate for the loss of IPEC.

Confining the analysis to direct and environmental costs alone (without considering local economic benefits), **the scenario that minimizes total costs over the period 2021–2050 is CHPE alone (Scenario B) at $12.8 billion ($11.9–$13.6 billion)** compared to $17.0 billion (90% CI: $16.1–$17.8 billion) for no action.

An extensive uncertainty analysis suggests that the main implications for decision making are robust to large changes to underlying modeling assumptions. CHPE alone (Scenario B) is likely to remain cost-competitive relative to no-action (Scenario A) even assuming large discounting of future GHG emissions.

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ACRONYMS AND ABBREVIATIONS

AUD	Australian dollar
CAD	Canadian dollar
CHPE	Champlain-Hudson Power Express
CI	confidence interval
CO_2	carbon dioxide
CPV	CPV Valley Energy Center
CLCPA	Climate Leadership and Community Protection ct
CVEC	Cricket Valley Energy Center
EEI	Edison Electric Institute
eGRID	Emissions & Generation Resource Integrated Database
FTE	full-time equivalent
GHG	greenhouse gas
GIS	geographic information system
GJ	gigajoule
GW	gigawatt
GW•h	gigawatt-hour
HHV	higher heating value
IDE	integrated development environment
IPEC	Indian Point Energy Center
JEDI	Jobs and Economic Development Impact
kW·h	kilowatt-hour
MJ	megajoule
MRIF	ministère des Relations internationales et de la Francophonie (Ministry of International Relations and La Francophonie)
MW	megawatt
MW•h	megawatt-hour
N_2O	nitrous oxide
NECEC	New England Clean Energy Connect
NG	natural gas
NO_x	nitric oxides
NOAA	National Oceanic and Atmospheric Administration
NPV	net present value
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYSERDA	New York State Energy Research and Development Authority
O_3	ozone
PM	particulate matter
$PM_{2.5}$	particulate matter < 2.5 μm
PM_{10}	particulate matter < 10 μm
SCC	social cost of carbon
SO_x	sulfur oxides
TW	terawatt
TW·h	terawatt-hour
USD	United States dollar
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Agency
U.S. EPA	United States Environmental Protection Agency
μm	micrometer (micron)

METRIC PREFIXES

Symbol	Metric prefix	Colloquial	Scientific and decimal notation
μ	**micro-**	**millionth**	**10^{-6} = 0.000001**
m	milli-	thousandth	10^{-3} = 0.001
c	centi-	hundredth	10^{-2} = 0.01
d	deci-	tenth	10^{-1} = 0.1
-	**-**	**one**	**10^{0} = 1**
da	deca-/deka-	ten	10^{1} = 10
h	hecto-	hundred	10^{2} = 100
k	**kilo-**	**thousand**	**10^{3} = 1,000**
M	**mega-**	**million**	**10^{6} = 1,000,000**
G	**giga-**	**billion**	**10^{9} = 1,000,000,000**
T	**tera-**	**trillion**	**10^{12} = 1,000,000,000,000**

Note: In U.S. customary units and in French, the abbreviations M and MM often denote thousands and millions respectively, from the value for one thousand in Roman numerals. We **do not** use that notation in this report. Abbreviations used in this report are **in bold**.

UNITS AND DIMENSIONS OF ANALYSIS

This report contains extensive analysis of energy and power. Energy is the quantity imparted to a material to perform work on it (to move or heat it). The usual metric unit of energy is the joule. One definition of the joule is the energy required to move a 1-kg mass through a 1-m distance upward against the force of Earth's gravity. Power is the rate of energy over time. One joule of energy transferred (e.g., over an electrical distribution system) per second is one watt (i.e., $1\ J\ s^{-1} = 1\ W$).

These (and other) units can be converted for ease of use using the metric prefixes above, i.e., 1,000 W = 1 kW. This is commonly done partially to avoid cumbersome leading or trailing zeros in text. The kilowatt-hour (kW·h) is a frequently used unit of energy equal to one kW of power sustained over one hour and is equal to 3.6 MJ.

Usage and capacity factors are calculated by dividing the energy supplied by a generator (in MJ) by the energy supplied if, hypothetically, the generator ran continuously over that period. For example, a 10-MW generator running continuously for one day would produce 864 GJ ($10 \times 10^6\ J\ s^{-1} \times 60\ s\ min^{-1} \times 60\ min\ h^{-1} \times 24\ h\ day^{-1}$ where $1\ W = 1\ J\ s^{-1}$ and 1,000 MJ = 1 GJ). A 10-MW generator that produces 500 GJ over this period has a usage factor of 58% (500 ÷ 864). 500 GJ is equivalent to 138.9 MW·h.

Commonly used units for energy and power as well as conversion factors are listed below. Abbreviations used in this report are **in bold**.

Quantity	System of measurement	
	Metric	**Imperial/U.S. customary**
Energy	**joule (J)**, calorie (cal), **kilowatt-hour (kW·h)**	British thermal unit (BTU), foot-pound (ft·lb)
Power	**watt (W)**	BTU s^{-1}, horsepower (hp)

Quantity	System of measurement								
	Metric					Imperial/U.S. customary			
Energy	**1 MJ**	=	**277.8 W·h**	=	238.9 kcal	=	947.8 BTU	=	73,7562.14 ft-lb
Power					1 MW	=	947.8 BTU s^{-1}	=	1,341 hp

1. INTRODUCTION

The electrical grid in the New York City area is undergoing a period of transition and stress. Since the 1970s, Downstate New York has drawn roughly 15 TW·h per year of nuclear power from Indian Point Energy Center (IPEC) in Westchester County, NY, roughly 40 miles from Midtown Manhattan (NYISO 2020a). However, one of IPEC's two generation units (IPEC 2) was taken offline in May 2020, and the final unit (IPEC 3) is scheduled to be retired in 2021 (NYISO 2020a, NYISO 2020b). Meanwhile, in 2019, the State committed to decarbonization of the electrical sector by 2040 (NYS 2019).

The closure of IPEC increases the challenges associated with New York State's ambitious renewable energy commitments. While Upstate New York benefits from substantial renewable energy capacity, transmission bottlenecks severely limit access to this energy by the New York City area formerly served by IPEC (NYISO 2017). For example, total interconnection capacity from Upstate to Downstate is roughly 5,175 MW or less than 25% of projected peak summer demand Downstate (20,866 MW for the period 2020–2038 in Zones G–K) (Howard et al. 2017; NYISO 2019). Meanwhile, in 2019, 69% of electrical supply to the grid Downstate derived from fossil fuels compared to only 23% Upstate (Zones A–F) (NYISO 2020a).

The closure of IPEC will therefore need to be met with some combination of reduced demand, decreased reliability, increased local generation (output and/or capacity) and/or increased transmission capacity (Lesser 2012). For example, the Champlain-Hudson Power Express (CHPE) has been proposed to facilitate the export of electricity supply from the Province of Quebec, Canada, directly to the New York City borough of Queens (TDI 2020). If built, CHPE would bypass bottlenecks that have increased the reliance of Downstate New York on fossil fuel generation, particularly at times of peak demand (NYISO 2017).

There is debate, however, over the relative merits of alternative near-term investments in New York's electricity sector. In general, there has been a lack of cross-cutting analysis that evaluates direct and indirect costs and benefits of potential alternatives using a common methodology. There has also been a lack of analysis of how ancillary environmental effects of various alternatives affect true cost-effectiveness when considered alongside direct economic impacts.

The Government of Quebec's Ministry of International Relations and La Francophonie (ministère des Relations internationales et de la Francophonie, MRIF) has requested an independent analysis of environmental and economic impacts associated with the proposed CHPE project in comparison to (or in conjunction with) potential alternative scenarios. This report summarizes a review and synthesis of expected direct and indirect economic and environmental impacts of possible future scenarios for the New York City area in the context of the anticipated closure of IPEC.

Impacts associated with future decisions are subject to large uncertainties and are sensitive to qualitative and quantitative modeling assumptions. We have therefore adopted a probabilistic modeling approach that aims to characterize the wide range of possible values for outcomes of interest. We produced results for scenarios that we determined to be technically, politically and socially plausible using publicly available data and transparent modeling assumptions. We have also specifically described the sensitivity of our results to various key assumptions. Finally, we note that our framework is adaptable and extensible and can be used to develop additional scenarios or evaluate alternative outcomes beyond those presented here.

2. METHODS

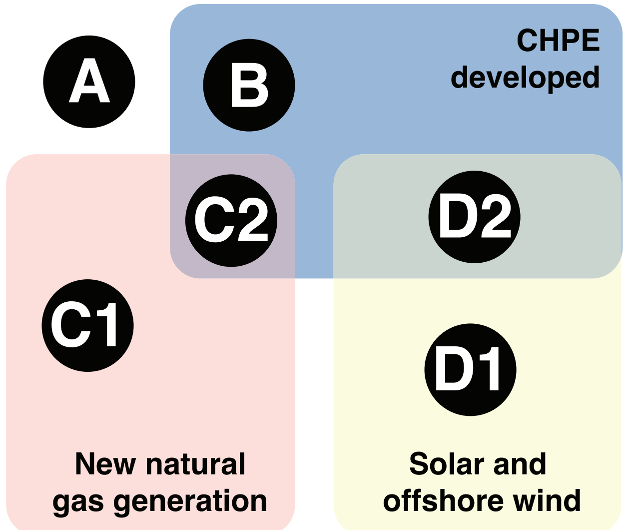
We developed a range of scenarios derived from potential decisions bearing on the electrical grid of Downstate New York relative to a baseline in which the closure of IPEC removes 15,304 GW·h per year of low-emissions power supply (NYISO 2020a). These scenarios are introduced and justified with regards to their feasibility in Section 2.1. For each scenario, we calculate direct costs (upfront and fixed costs for new construction projects plus variable operating and fuel costs, Section 2.2). For new construction projects, we estimate indirect economic benefits generated by local expenditures and employment effects (Section 2.3). For all scenarios, we evaluate foremost environmental and human health impacts, providing an economic analysis where possible (Section 2.4). All numerical modeling was carried out in RStudio (Section 2.5).

2.1 Scenario Development

New York State faces a number of interrelated choices about the future of its electrical grid. Because of transmission bottlenecks, demand-side stresses Downstate can be addressed only partially by Upstate generation capacity, until and unless there are substantial investments in local transmission infrastructure (NYISO 2017; U.S. DOE 2015). For the purposes of scenario creation and analysis, we therefore focus specifically on the Downstate region. We consider these to correspond to NYISO Zones G, H, I, J and K. (In Section 3.8.1, we carry out a sensitivity analysis to evaluate the impact on our results of considering a narrower region around New York City.) This analysis considers costs and impacts associated with a number of potential responses to the closure of IPEC (Zone H), which disproportionately stresses Downstate New York and the New York City area.

Our base case (Scenario A, Section 2.1.1) assumes that, following the closure of IPEC, there are elopment of the Champlain-Hudson Power Express (CHPE), which would provide roughly 8,300 GW·h per year of imported hydropower to Zone J (TDI 2010). Existing generating facilities make up the rest of the supply as in Scenario A, so that the total power supplied is 15,304 GW·h per year. In Scenario C1 (Section 2.1.3), we consider the development of a new natural gas plant sited at an uncertain location in Downstate New York supplying 15,304 GW·h per year. In Scenario D1 (Section 2.1.4), we consider power supplied by future build-out of Downstate offshore wind and solar generating capacity estimated from recent trends and policy targets. We also consider the development of CHPE in conjunction with both new natural gas (Scenario C2) and future offshore wind and solar (Scenario D2) capacity. While CHPE (Scenarios B, C2, and D2) corresponds to a specific future project, natural gas (Scenarios C1 and C2) and wind and solar (Scenarios D1 and D2) are hypothetical. For these hypothetical projects, we develop estimates for plausible parameter values based on recent past projects. These five scenarios are summarized in Figure 1 and described in detail below.

Figure 1. Euler Diagram Showing How Scenarios of Analysis (Black Circles) Represent Different Combinations of Infrastructure Interventions (Shaded Rectangles) after the Closure of IPEC



Note. Scenario A assumes no infrastructure development.

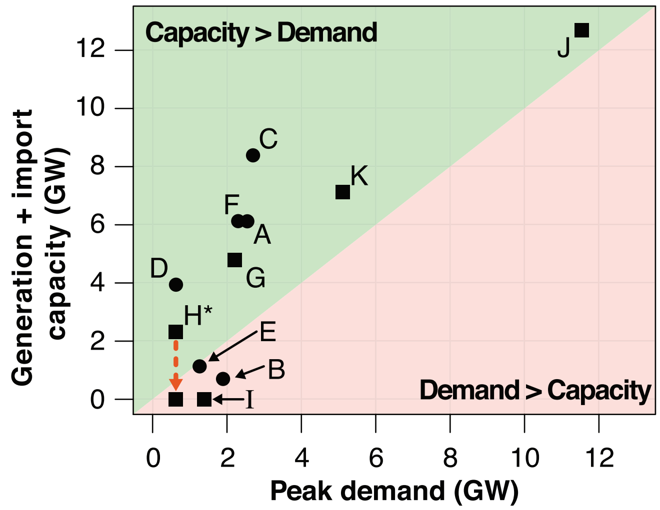
2.1.1 Scenario A – No Increased Generation or Transmission Capacity

We retain as a base or reference case the possibility of no new generation or transmission capacity Downstate following the closure of IPEC. In this scenario, output of existing generating facilities in the Downstate region (NYISO Zones G–K) is increased to replace the 15,304 GW·h per year of output formerly provided by IPEC (NYISO 2020a).

This scenario is technically feasible and very likely for the near future. IPEC is ceasing generation between May 2020 and April 2021, and there are limited prospects for replacing its output from new infrastructure in that period. Nameplate generation capacity in Zones G–K is 23,982 MW, and interconnection capacity is 4,893 MW from New England and New Jersey and 5,175 MW from Upstate (Zones E and F) (NYISO 2020a). This compares to peak forecasted demand of 21,946 MW (NYISO baseline scenario) or 24,700 MW (NYISO high load scenario) by 2038 (NYISO 2020a). Figure 2 plots NYISO zones in terms of the sum of capacity of local generation and non-NY imports versus peak local demand projected for the period 2020–38 (NYISO 2020a).

This scenario becomes less likely for longer timescales as projects are developed in response to price signals and reliability requirements associated with future plant retirements. Currently planned retirements in the Downstate region are, to our knowledge, limited to IPEC and the 52.4 MW West Babylon 4 fuel oil generating station in Long Island (NYISO 2020a), however, PA Consulting Group (2017) identifies 4,702 MW of installed oil and gas capacity in Zone J "at risk of retirement" by 2027. Meanwhile, expected demand increases with time, and these forecasts are increasingly uncertain for longer timescales. For example, peak forecasted demand by 2050 rises to 22,587 MW (NYSIO baseline scenario) or 27,611 MW (NYISO high load scenario) (NYISO 2020a).

Figure 2. NYISO Zone by the Sum of Local Generation (Nameplate) and Non-NY Interconnection Capacity Versus Peak Local Demand in the Period 2020–2038



Note. Square points are Downstate zones. *Orange arrow shows impact of closing IPEC on Zone H.

All analyses we reviewed suggest that increased output of Downstate natural gas facilities is the most likely grid response to the closure of IPEC (City of New York 2013, Ross 2018). At present, the usage factor of Downstate natural gas facilities is 28%, compared to the typical range of 51–87% reported by NREL (2019a) (90% of Downstate natural gas facilities have usage factors between 0.1–76%). Increasing output of natural gas facilities could yield a further 28–72 TW·h per year, compared to the 15 TW·h per year lost from the closure of IPEC. However, total installed capacity of natural gas is only 13,901 MW compared to expected peak demand of 21,946 MW by 2038, pointing to the continued (and possibly increased) need for local oil generators and imports at times of peak demand. At present, Downstate fuel-oil generators have an annual capacity-weighted average usage factor of 5% against a total installed nameplate capacity of 7,378 MW.

Conversely, the upper bound of additional potential offshore wind, solar, and hydropower generation Downstate is less than 0.5 TW·h per year. This assumes the capacity-weighted average usage factor of Downstate hydropower assets can be increased from 23% to 66%, the upper limit of the range of plausible averages reported by NREL (2019a). However, given the low marginal costs associated with hydropower generation, it is likely that there are technical reasons for this low usage factor, and substantial increases in output are likely not possible. In Scenario D (Section 2.1.4), we consider the costs and benefits of potential build-out of Downstate solar and offshore wind assets using a timeline based on historic trends and planned generation projects. Table 1 summarizes the statistics for real and available generation in Downstate New York.

Table 1. Installed Capacity and Available Generation for Select Technologies in Downstate NY[a]

	Hydropower	Fuel oil[b]	Natural gas	Solar[c]	Offshore wind
Installed capacity (MW)[d]	107	7,379	13,902	57	0
Generation in 2019 (GW·h)[d]	212	2,986	34,257	56.5	0
Usage factor in 2019 (%)[e]	23	5	28	10	NA
Potential capacity factor (%)[f]	60–66	20[g]	51–87	15–27	28–52
Potential added generation (GW·h year^{-1})	350–407	9,942	27,858–71,688	27–86	0

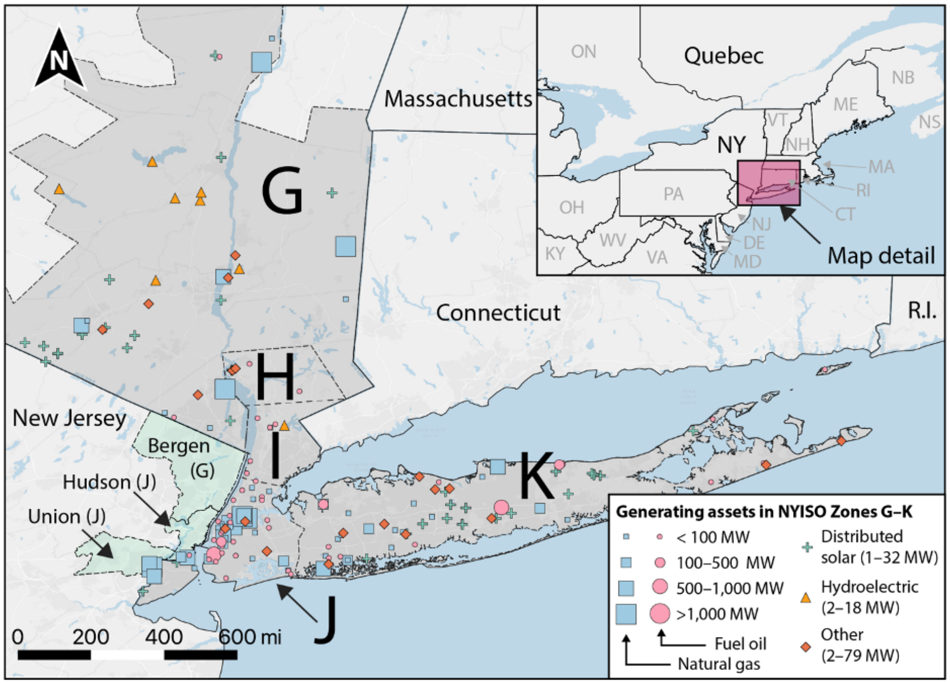
[a] NYISO Zones G–K.
[b] Including fuel oil #1 (kerosene), #2 (bunker A), and #6 (bunker C).
[c] Excluding distributed solar projects which are assumed to be operating at peak capacity
[d] Data from NYISO (2020a).
[e] Calculated by dividing total generation by total nameplate capacity across all generators.
[f] Ranges from NREL (2019a) unless otherwise specified.
[g] Typical upper limit of peak summer demand nationally (U.S. EIA 2017); theoretical capacity higher but uneconomical.

In Scenario A, we consider that power no longer delivered by IPEC is instead supplied by an uncertain combination of generating assets in Downstate New York. Because of the very low marginal costs of nuclear power and the relatively high usage factor of IPEC (76% in 2019), it is reasonable to assume that IPEC was primarily contributing to baseload power. We consider it most realistic to assume that power no longer supplied by IPEC will predominantly be replaced by output from natural gas generators given their relatively low present-day utilization, large contribution to baseload power, and marginal costs. (Marginal costs of various generating technologies are summarized in Table 4 and Table 5.)

To calculate the potential contributions of individual generation facilities, we preferentially draw on generators that are closer to their maximum capacity under the hypothesis that these are likely to be the most cost-effective. (Generator-specific cost data is proprietary, so we are limited to this indirect inference.) Figure 3 maps generating assets (excluding IPEC) in NYISO Zones G–K.

In a sensitivity analysis (Section 3.8), we demonstrate how overall results are affected by parameters and modeling assumptions. In Section 3.8.1, we evaluate how results are impacted by confining our analysis to a narrower region around New York City (NYISO Zones H–J) rather than the broader Hudson Valley and Long Island region (NYISO Zones G–K). In Section 3.8.2 we consider the impact of other generator technologies, notably those fired by fuel oils, that may respond to the closure of IPEC. This corresponds to the possible effect that the closure of IPEC may have on the output of the broader portfolio of generation assets.

Figure 3. Map of Generating Assets Reporting to eGRID (U.S. EPA 2020) Located in NYISO Zones G–K



Note. Map includes assets in three counties in New Jersey which are reported in NYISO (2020a) as contributing to Zones G and J. Hatched lines delineate NYISO zones and relevant NJ counties. IPEC (Zone H) is excluded. Base map from Esri et al. (2020).

More detailed simulations of the response to the closure of IPEC might model dynamics of generator spin-up, transmission and interconnection capacity, power losses with distance and time- and region-specific variable generation costs and wholesale prices (Dimanchev et al. 2020, Howard et al. 2017). Such simulations are likely to narrow the range of possible energy mixes by considering more realistic operational constraints and optimizing for total cost. In the future, the results of such simulations could be used as inputs to the model developed here to narrow the uncertainties in the values presented for ancillary costs and benefits.

2.1.2 Scenario B – Increased Transmission of Hydropower from Quebec to Zone J

CHPE is a proposed 1,000-MW transmission line from the Quebec/New York border to Queens, NY (NYISO Zone J) via Lake Champlain, the Hudson River and the Hudson River Valley (TDI 2010). CHPE would deliver power from the Hydro-Québec grid directly to the New York City area, bypassing existing bottlenecks in New York State.

In Scenario B, we consider that CHPE would replace with hydropower 8,322 GW·h per year of the Downstate supply formerly provided by IPEC based on an average capacity factor of 95% (PA Consulting Group 2017). We assume that capital costs are incurred in 2021 and that power is supplied starting in 2025 (TDI Inc. 2020). We note that the regulatory approval process for this project is already largely complete and this lead time therefore reflects construction only. After

2025, we assume the rest of the power formerly supplied by IPEC (6,982 GW·h per year) will be provided by existing Downstate generation as in Scenario A. Between 2021–2024, all 15,304 GW·h per year demand formerly supplied by IPEC is assumed to be met with existing local generation assets as in Scenario A.

2.1.3 Scenarios C1 and C2 – Increased Local Natural Gas Generation

In these scenarios, we consider the possibility that power formerly supplied by IPEC is satisfied with new natural gas generation in the New York City area. We consider that costs are borne in 2021 for a natural gas facility at an uncertain location in Zones G–K. The likely timeframe for completion of a new natural gas plant is eight years (i.e., power delivery would start in 2029 if a decision were taken in 2021). This is based on the recent cases of Cricket Valley Energy Center (CVEC) and CPV Valley Energy Center (CPV) in Dover, NY, and Wawayanda, NY, respectively (both in Zone G). CVEC has a nameplate capacity of 1,176 MW and entered service in 2019 following a permitting and construction process that began in 2011 (CVEC 2012, NYISO 2020a). CPV has a nameplate capacity of 770 MW and entered service in 2018 following permitting and construction that began in 2008 (NYISO 2020a, TRC 2009). This does not reflect the added difficulties of developing a natural gas plant in the setting of New York State's legal obligations to decarbonization under the Climate Leadership and Community Protection Act (CLCPA).

In Scenario C1, we consider that all 15,304 GW·h per year formerly provided by IPEC are provided by a future gas plant as of the start of 2029, the earliest likely operational date. In Scenario C2, we consider that CHPE is developed as described in Scenario B and will provide 8,322 GW·h per year beginning in 2025 and that new gas generation supplies the balance of 6,982 GW·h per year beginning in 2029. In both Scenarios C1 and C2, demand not satisfied by CHPE and/or new natural gas generation is satisfied with existing assets as in Scenario A.

2.1.4 Scenarios D1 and D2 – Increased Local Solar and Offshore Wind Generation

In these Scenarios, we consider costs and benefits associated with expansion of offshore wind and solar technologies to the extent that they compensate for generation lost by the closure of IPEC. We consider recent trends in rate of build-out of offshore wind and solar projects in New York to reflect the timing of costs and benefits. Current installed capacity of solar, offshore wind, and battery storage is reported in Table 2 for New York State as a whole and the Downstate region in particular.

Expansion of utility offshore wind and solar projects is determined many years in advance and is tracked by NYISO as projects move through the planning process. Figure 4 plots proposed nameplate capacity for offshore wind, solar, and battery storage versus proposed start date. These dates range from the recent past (late 2019) to 2025. Over this period, 2,249 MW of utility solar projects and 5,997 MW of wind projects have been proposed. In Downstate regions (NYISO Zones G–K), this totals 249 MW for solar and 2,268 MW for offshore wind.

Installed capacity of distributed solar panels has been increasing much more rapidly statewide and Downstate for the past several years (Figure 5). NYSERDA tracks completed and planned distributed solar projects but does not report expected completion dates for planned projects. Currently planned distributed projects add up to 1,469 MW installed capacity statewide, including 398 MW Downstate (with expected energy production of 1,724 GW·h per year and 467 GW·h per year respectively). This adds to 2,249 MW of utility solar planned to come online by 2025 as described above. Assuming recent trends continue (addition of 240 MW and 112 MW in distributed capacity per year statewide and Downstate, respectively, since 2015), currently planned distributed projects will be built by 2027 (2023 for Downstate). Table 3 plots expected rates of build-out of renewable projects for the near future.

Table 2. Current Installed Capacity of Wind, Solar, and Storage in New York State

Project type	Statewide		Downstate (NYSIO Zones G–K)	
	Installed capacity (MW)	Energy output (GW·h year^{-1})	Installed capacity (MW)	Energy output (GW·h year^{-1})
Battery storage[a]	10	N/A	10	N/A
Solar (distributed)[b]	1,781	2,073	837	978
Solar (utility)[a]	57	47	57	47
Wind[a]	1,985	4,727	0	0

[a] Data from NYISO (2020a). Energy output (GW·h year^{-1}) is data reported for 2019.
[b] Data from NYSERDA (2020). Energy output (GW·h year^{-1}) is reported as "expected."

Table 3. Projected Expansion of Wind, Solar, and Storage Capacity in New York State

Project type	Statewide		Downstate (NYSIO Zones G–K)	
	Capacity added (MW year^{-1})	New projects (number year^{-1})	Capacity added (MW year^{-1})	New projects (number year^{-1})
Battery storage	>210[b]	5	>145.6[b]	2
Solar (distributed)	240	13,851	112[c]	9,924
Solar (utility)	450	11	50[c]	3
Wind[a]	1,199	6	454[d]	1

[a] Downstate wind is offshore.
[b] Excluding projects with no listed capacities.
[c] State goal of 6,000 MW likely achieved in 2027.
[d] State goal of 9,000 MW of offshore wind likely achieved in 2040.

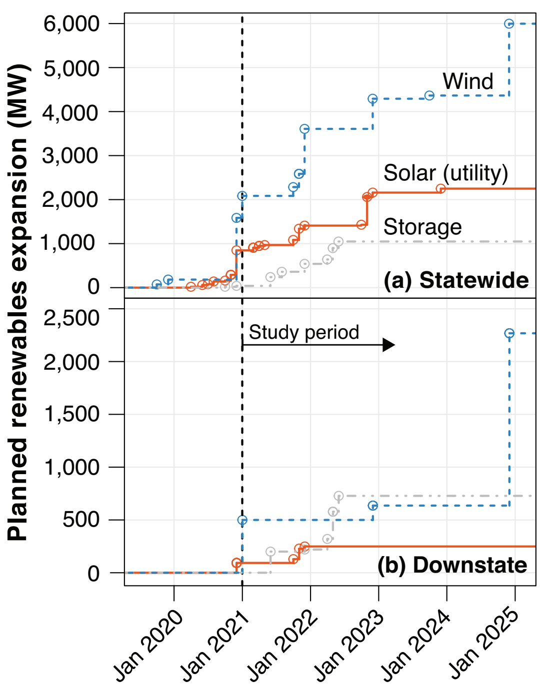
New York State has a goal of 6,000 MW of installed solar capacity by 2025 (NYSERDA 2019a) and 9,000 MW of Downstate offshore wind by 2035. At current rates of build-out, the solar objective will be achieved by 2027, and the offshore wind objective will be achieved by 2040.

Recent large-scale wind and solar projects had a lead time between proposal and power delivery of roughly four to five years. For example, Copenhagen Wind Farm proposed in 2013 (edr

Companies 2013) and Shoreham Solar Commons proposed in 2014 (PSEG Long Island 2017) both came online in 2018. The median time for completion of distributed solar projects is less than six months. Therefore, we consider capital costs to be borne in the same year as power delivery for distributed solar projects and four years in advance for utility solar and offshore wind.

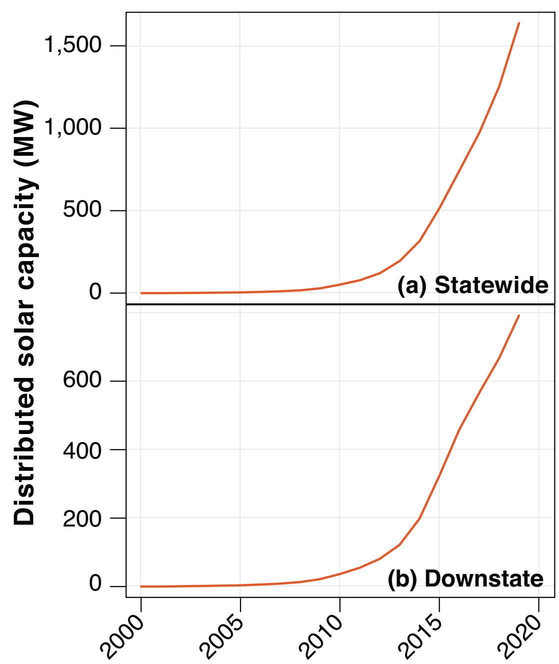
In Scenario D1, we consider ongoing build-out of distributed and utility solar and offshore wind according to the schedule in Table 3. In Scenario D2, we consider this build-out alongside the development of CHPE as described in Scenario B. In both Scenarios D1 and D2, demand not satisfied by CHPE and/or new natural gas generation is satisfied with existing local generation assets as in Scenario A. In both Scenarios D1 and D2 we consider renewable build-out only up to the point at which the output from IPEC (15,304 GW·h) is greater than 50% likely to have been replaced by wind and solar and/or CHPE, or until State targets are met, whichever comes first.

Figure 4. Planned Cumulative Expansion of Photovoltaic (Utility) and Wind Power Generation Facilities and Battery Storage in (A) New York State and (B) Downstate Regions (NYISO Zones G–K)



Note. Expansion is presented relative to existing operational capacity using proposed power delivery dates even if those dates have already passed. Circles correspond to discrete generation projects. Data are from NYISO (2020a).

Figure 5. Cumulative Installed Capacity of New York State Distributed Solar Projects (A) Statewide and (B) Downstate (NYISO Zones G–K)



Note. Projects currently planned increase installed capacity by a further 1,469 MW statewide, including 398 MW Downstate. Planned dates are not available for that added capacity. Data are from NYSERDA (2020).

In both Scenario D1 and Scenario D2, state solar targets are met after seven years and we assume build-out ceases. A fraction of this is attributable to decisions taken before the study period and independent of the closure of IPEC. (For example, NYISO and NYSERDA report 1,838 MW of solar capacity as of 2020 out of a total target of 6,000 MW.) Build-out of wind is sustained for 13 years in Scenario D1 and 8 years in Scenario D2, until the generation from IPEC is replaced (in conjunction with solar and, in Scenario D2, CHPE). We do not consider costs or benefits of further build-out of utility wind beyond what is required to compensate for IPEC (i.e., the rest of the generation required to achieve the State's goal of 9,000 MW of offshore wind). We also do not consider costs or benefits associated with decisions taken before the start of the model horizon (i.e., before 2021).

Wind generators have an operating lifespan on the order of 20–25 years, which is shorter than the 30-year horizon we consider in this analysis (NREL 2019b). We consider an operational lifetime of future offshore wind equal to 25 years based on the recently awarded Sunrise and Empire offshore wind projects (NYSERDA 2019b). Wind projects awarded in 2021 would deliver first power in 2025 and retire in 2030, the last year of our analysis. We account for this in the calculation of benefits. We assume that generation supplied by wind awarded in 2021 would be supplied by legacy assets in the year 2030 as in Scenario A. Available data for solar generators point to a service life longer than the model time horizon, so we do not consider retirement of new solar assets (NREL 2019b). Costs reported by NREL (2019b) for battery storage assume a useful battery lifetime of 15 years, which is shorter than the 30-year horizon evaluated here. Consequently, we account for replacement of batteries at the end of their lives.

2.2 Direct Costs

We aggregated direct costs associated with capital expenditures that have fixed and variable operation and maintenance costs (Table 4). Upfront and fixed costs are considered only for new generation capacity (Scenarios B, C1, C2, D1, D2). Variable and fuel costs are payable for both existing capacity with increased generation (Scenario A) and new capacity for every year of generation. Fuel costs are displayed in Table 5. Fuel and variable costs are payable when power is drawn (starting in year of first power for new generation facilities). Because cost data are proprietary, we cannot know plant-specific values and therefore use the ranges provided in Table 4 for each technology. We use the same ranges for development of new natural gas (Scenarios C1 and C2) as for existing assets (Scenario A).

We do not consider direct fuel costs associated with power delivered by CHPE because marginal costs associated with hydropower production are virtually zero. However, in Section 3.7 we evaluate the impact on overall cost-effectiveness under the assumption of various opportunity costs for that power; these costs would ultimately be reflected in prices paid to Hydro-Québec.

Installed capacity in MW of a future natural gas plant (Scenarios C1 and C2) required to compensate for IPEC is a function of an uncertain future average capacity factor (Table 4). Capacity factor also determines energy output of offshore wind and solar build-out (Scenarios D1 and D2) which is scheduled in terms of installed capacity. All values displayed are modeled as uniform distributions or point values depending on data availability.

Direct costs will be borne by consumers, investors, or governments in New York or Quebec according to the scenario analyzed and the terms of eventual contracts. Because the terms of future contracts are presently hypothetical, in this analysis we calculate total overall costs and do not apportion them to different parties.

Table 4. Direct and Variable Costs and Capacity Factors by Generation Type[a]

Generation type	Upfront (10^6 \$ MW^{-1})	Fixed O&M (10^3 \$ MW^{-1} $year^{-1}$)	Capacity factor (%)[b]	Variable O&M (\$ GJ^{-1})
Battery storage[c]	1.21–1.50	0.03–0.04	N/A	0
Bituminous coal	N/C	N/C	N/C	1.44–2.89
Butane	N/C	N/C	N/C	NA[d]
Fuel oil #1 (kerosene)	N/C	N/C	N/C	4.88–6.51[e]
Fuel oil #2 (bunker A)	N/C	N/C	N/C	4.88–6.51[e]
Fuel oil #6 (bunker C)	N/C	N/C	N/C	4.88–6.51[e]
Hydropower (CHPE)	2.96–4.45[f]	2.96–4.45[g]	95[h]	0
Methane (biogas)	N/C	N/C	N/C	1.45–1.74
Natural gas	0.95–2.3	11.5–35.4	51–87	0.86–2.03
Nuclear	N/C	N/C	N/C	0.58
Refuse (solid waste)[i]	N/C	N/C	N/C	1.45–1.74
Solar (distributed)[j]	1.9–2.9	18.8–25.0	12–21	0
Solar (power station)	1.1	20.8	15–27	0
Wind (offshore)	3.8–7.5[k]	102.1–152.1	28–52	0

[a] From NREL (2019a) unless otherwise stated; dollar values reported are 2019-USD; units of power and energy are those delivered to the grid (already adjusted for thermal efficiency).
[b] Applies to new generation projects only (Scenarios B, C1, C2, D1, D2).
[c] Costs displayed are for the year 2020. We consider that storage costs decline by 1–4% per year through 2050 following the projections of NREL (2019a).
[d] Only serves as secondary fuel; costs are assigned based on primary fuel type of each generation facility.
[e] Value for heavy fuel oils from Suding et al. (2012).
[f] Pooling available estimates for capital costs of \$3.8 billion in 2010-USD (TDI 2010) and \$3.0 billion in 2020-USD and a rated capacity of 1,000 MW.
[g] Assuming annual operation and maintenance equal to 0.1% of capital costs for transmission projects based on NREL (2016).
[h] From PA Consulting Group (2017).
[i] Based on values for methane (biogas).
[j] Values pooled across residential and commercial distributed projects.
[k] Inclusive of grid connection costs.
N/C: Technology not considered for new construction; fixed costs not considered for increased output of existing facilities.

In Scenarios B, C1, C2, D1, and D2 (new construction of generating assets), we consider variable lead times between the year when upfront costs are payable (start of planning, permitting, and construction process) and the year first power is delivered. For new hydropower transmission (Scenarios B, C2, and D2) and natural gas generation (Scenarios C1 and C2), we consider upfront costs to be payable in 2021. We consider a lead time to first power of four years for hydropower transmission capacity as discussed in Section 2.1.2, eight years for new natural gas capacity (Section 2.1.2) and four years for large-scale offshore wind and solar projects (Section 2.1.4). For distributed solar we consider no lead time between upfront costs and power delivery because greater than 90% of projects reported by NYSERDA moved from proposed to completed in less than one year (NYSERDA 2020).

For future costs (e.g., fuel costs for future years of generation), our analysis considers a discount rate of 3% to be consistent with the derivations used for social cost of carbon (SCC) (Section 2.4.1) and economic impacts of atmospheric emissions (Section 2.4.2). We however explore the effect of alternate assumptions of discount rate on cost-effectiveness of alternative energy transition scenarios; this sensitivity analysis considers the discount rate to be applied to both direct costs and the values used for SCC (Section 3.8.3).

2.3 Indirect Economic Effects

The direct costs described above do not comprehensively capture the economic impacts of potential energy transition scenarios. For example, dollars spent on construction and operation of new generation or transmission infrastructure have second-order effects via job creation and overall local economic stimulus. To estimate these indirect effects, we used the publicly accessible Jobs and Economic Development Impact (JEDI) models (NREL 2020). The JEDI models simulate the economic linkages between industries and the likely impact of energy projects on the relative demand for various goods and services nationally and for each state using economic input-output models. We evaluate indirect effects of new construction projects only (natural gas, hydropower transmission, solar, and offshore wind). We assume that local economic effects of marginally increasing output of existing generation facilities (Scenario A) is negligible. We parameterize the JEDI models using the information synthesized in Table 4 and Table 5.

The simulation for increased hydropower transmission from Quebec (CHPE, Scenarios B, C2, and D2) used the JEDI model for transmission projects. It is possible that JEDI may underestimate the indirect economic effects of this alternative. CHPE is substantially more technically complex than most transmission projects, for example, spanning modes (underwater, overland) and levels of urbanization. To the extent possible, we calibrated the JEDI models to match reported budget line items, and we compared their output to previous economic analysis (PA Consulting Group 2017). Notably, we imposed property tax rates between 1.0–1.5% to achieve an average tax expenditure of roughly $50 million per year and considered the project as a series of shorter installations (74 to 130 miles long) to achieve a total capital cost of $8.9–$13.5 million per mile ($3.0–$4.5 billion over 333 miles).

Table 5. Fuel Costs and Default Greenhouse Gas Emissions Factors

Generation type	Efficiency (%)[a]	Fuel costs ($ GJ^{-1})[a,b,c]	Greenhouse gases (g MJ^{-1})[c,d]		
			CO_2	CH_4	N_2O
Bituminous coal[e]	29–39	1.98	98.4	0.012	1.7E–3
Butane[e]	33–48[f]	11.31–14.33[g]	68.3	3.2E–3	6.3E–4
Fuel oil #1 (kerosene)[e]	33–48[f]	11.31–14.33[g]	77.3	3.2E–3	6.3E–4
Fuel oil #2 (bunker A)[e]	33–48[f]	11.31–14.33[g]	78.0	3.2E–3	6.3E–4
Fuel oil #6 (bunker C)[e]	33–48[f]	11.31–14.33[g]	79.2	3.2E–3	6.3E–4
Hydropower (CHPE)	N/A	0	0[h]	0[h]	0[h]
Methane (biogas)[i]	25–35	2.96	54.9	3.4E–3	6.3E–4
Natural gas	45–53	2.72	56.0	1.1E–3	1.1E–4
Nuclear[e]	33	0.63	0	0	0
Refuse (solid waste)[e]	25–35[h]	2.96	99.0	7.6E–3	3.8E–3
Solar (distributed)	N/A	0	0	0	0
Solar (power station)	N/A	0	0	0	0
Wind (offshore)	N/A	0	0	0	0

[a] From NREL (2019a) unless otherwise stated.
[b] Monetary values reported are in 2019-USD.
[c] Energy values are energy content of fuel and must be combined with efficiency to calculate values per GJ distributed to grid.
[d] From U.S. EPA (2014) and aggregated in warming potential model by multiplying values reported here by 1 (CO_2), 25 (CH_4) and 298 (N_2O) to calculate CO_2 equivalents based on 100-year global warming potential.
[e] Contribution of technology only considered in certain sensitivity analyses (Section 3.8.2).
[f] Value for heavy fuel oils from Suding et al. (2012).
[g] Values from U.S. EIA (2019) for petroleum liquids pooled across electric sector and independent power producers.
[h] We consider that there are negligible greenhouse gas emissions associated with drawing on reserve hydropower production capacity because no new reservoirs are contemplated.
[i] Based on values for methane (biogas).

Our ability to simulate the indirect economic effects of distributed solar projects (which drive overall solar capacity in New York State) is limited. The JEDI model for solar installations is based on large-scale concentrating solar facilities and does not likely provide a good estimate of individual distributed solar projects which are numerous (>10,000 per year statewide) but have very small capacities (~0.01 MW) and comparatively simple construction processes. For example, the JEDI model estimates construction-phase job creation at zero jobs for the typical capacity of a distributed solar project. This is likely an accurate reflection of the marginal impact of individual projects (no job created specifically for any one small project) but does not reflect the growth of an industry to support these projects when combined. For example, NYSERDA claims that the solar industry supports close to 12,000 jobs in New York, and this is largely driven by small-scale distributed projects (NYSERDA 2020).

2.4 Environmental Impacts and Costs

We evaluate the likely impact of energy transition scenarios on emissions of greenhouse gases (Section 2.4.1) and criteria air pollutants (Section 2.4.2) and associated economic impacts. Existing generating stations with rated nameplate capacity greater than or equal to 100 MW were paired with U.S. EPA's Emissions & Generation Resource Integrated Database (eGRID) in order to use site-specific emissions factors reported for 2018 (U.S. EPA 2020). Other generating facilities and hypothetical future generating facilities use default emissions factors reported in Table 5 (greenhouse gases) and Table 6 (criteria air pollutants). For new natural gas (Scenarios C1 and C2) we consider that emissions of GHG and air pollutants cannot be greater than those calculated for Scenario A (use of legacy assets) because future development of less efficient technologies is highly unlikely. In Section 2.4.3, we review other potential environmental impacts associated with each energy transition scenario, the economic value of which we did not quantify.

We adjusted future NO_X emissions factors to be consisted with the recently adopted standards for emissions between the months of May and September (NYS 2020). Where reported emissions exceeded the future standard (1.5 lbs and 2.0 lbs per MW·h for gas and fuel oil generators respectively) on an annual basis, real reported emissions were considered for seven months of the year (October to April) and the guideline value was retained for the other five months.

2.4.1 Greenhouse Gases

For each scenario, GHG emissions are calculated for every year of power delivery for every relevant generating asset. Power output is calculated for existing and hypothetical future generating assets as described in Section 2.1.

We quantify the economic impact of future GHG emissions by assigning a social cost of carbon (SCC). There is substantial variability across the literature in the value used for SCC of marginal emissions depending on discount rate, climate forecasts, decarbonization assumptions and geographic boundaries of analysis (Nordhaus 2014). For example, a recent review identified a range of -13.36 to 2,386.91 $ per tonne CO_2 with a mean value of 54.70 $ per tonne CO_2 (Wang et al. 2019).

In New York State, the process to introduce a carbon price to the wholesale electricity market is ongoing (NYISO 2018, Tierney and Hibbard 2019). In 2018, the State Department of Public Service and NYISO proposed a value of $52 per tonne of CO_2 rising to $60 by 2030 (converted to 2019-USD from 2007-USD) (Myers 2018, NYISO 2018). This corresponds to the central estimate of the value of SCC derived by the Interagency Working Group on Social Cost of Greenhouse Gases (2016), assuming a discount rate of 3%.

We did not identify any other candidate values or derivations for SCC in New York State, and the value proposed by the State and NYISO is close to the literature average as reported by Wang et al. (2019). Therefore, in our analysis, we consider the Interagency Working Group's central estimate of the SCC (3% discount rate) for the period 2021–2050. However, in a sensitivity analysis, we also consider the effect of alternative SCC values on overall cost-effectiveness of potential energy transition scenarios (Section 3.8.3).

2.4.2 Local Air Quality

For each scenario, emissions of criteria air pollutants are calculated for every year of power delivery by relevant generating facilities. Site-specific emission factors from eGRID are available for SO_2 and NO_2, which we used for all facilities with nameplate capacities greater than or equal to 100 MW. For particulate matter (PM) and carbon monoxide (CO), we used default emissions factors from U.S. EPA (Table 6). U.S. EPA considers that 100% of particulate matter emissions from natural gas plants are in the $PM_{2.5}$ size fraction (Eastern Research Group 1998). We adopt that same assumption here. We consider the contribution of oil- and coal-fired power plants in a sensitivity analysis (Section 3.8.2). The particle size distribution of particulate matter from these sources is highly variable. For fuel oils, we consider 42–96% of particulate matter as $PM_{2.5}$ based on U.S. EPA (2017). For coal, we consider 21–44% as $PM_{2.5}$ based on Ridlington et al. (2007).

Muller and Mendelsohn (2009) calculated marginal economic impacts associated with emissions of SO_2, NO_x, PM_{10}, and $PM_{2.5}$ for all counties in the United States. These correspond to the expected additional burden of disease, premature mortality and other environmental effects, which vary according to population density and local atmospheric chemistry. Impacts also vary by stack height (lower economic impacts with higher stacks). For all counties in which NYISO reports generating assets, we cross-referenced the marginal economic impacts reported by Muller and Mendelsohn (2009) for these contaminants (pooled as uniform distributions across all stack heights). Economic valuations provided by Muller and Mendelsohn (2009) assume a discount rate of 3%.

The economic valuations retained by Muller and Mendelsohn (2009) for health endpoints of interest are summarized are summarized in Table 7. On a national basis, those health endpoints account for 94% of overall economic impacts of air pollution, with the balance attributable to damage to structures, crops, timber stocks and other ecosystem endpoints (Muller and Mendelsohn 2007). We neglect those here. Muller and Mendelsohn (2009) combined these valuations with dose-response information from the epidemiology literature and county-specific baseline air-quality and demographic data to calculate economic impacts of marginal emissions in each county. Those aggregated economic distributions are summarized in Table 8 and are the basis for the analysis we undertake here.

Economic impact assessments for CO emissions have been less well synthesized. For CO emissions, we identified four studies that calculate and/or cite the economic cost of health impacts associated with marginal or average CO emissions (Table 9). We pool the values reported by these studies into a uniform distribution of 2–1,982 USD per tonne.

Table 6. Default Air Emissions Factors and Higher Heating Value (HHV) by Fuel

	Emission factor (kg $tonne^{-1}$)[a]				HHV ($MJ\ kg^{-1}$)[b]
	SO_x	NO_x	CO	PM	
Bituminous coal[c,d]	31.0–76.1[e]	3.7–16.5	0.25–5.5	0.060–10.0[f]	27.3
Butane[d,g]	0.010[h]	3.3	1.7	0.16	49.1
Fuel oil # 1 (kerosene)[d,i]	0.031[j]	2.9	0.72	0.29	45.6[k]
Fuel oil # 2 (bunker A)[d,l]	0.031[j]	1.4–3.4	0.71	0.28	45.6[k]
Fuel oil # 6 (bunker C)[d,m,n]	5.9[n]	3.1–5.7	0.61	0.0060–0.043[o]	42.2[p]
Hydropower (CHPE)	0	0	0	0	NA
Methane (biogas)[d,q,r]	0.012[s,t]	0.68–5.1	0.12–15.4	0.17–0.99	52.2[s]
Natural gas[m,r,u]	0.012[t]	2.1–2.9	1.7	0.010	52.2
Nuclear[d]	0	0	0	0	N/A
Refuse (solid waste)[d,v]	0.20	1.7–3.9	4.8	0.43–4.3	16.4–20.6
Solar (photovoltaic)	0	0	0	0	N/A
Wind (offshore)	0	0	0	0	N/A

[a] Values span possible firing configurations and emissions control technologies except where otherwise noted; must be combined with HHV to calculate emissions per unit energy in fuel and thermal efficiency (Table 5) for unit energy delivered to grid.
[b] Values from Wright et al. (2009).
[c] Emissions factors from U.S. EPA (1998a); not considering values for hand-fed units or fluidized bed combustors.
[d] Contribution of technology only considered in certain sensitivity analyses (Section 3.8.2).
[e] Assuming sulfur content ranging from 2–4% (uniform distribution) (Zheng and Yan 2013).
[f] Assuming ash content of 10% (EEI 2018, Michalski et al. 1998).
[g] Emissions factors from U.S. EPA (2008); assuming density of 584.6 kg m^{-3} (Wright et al. 2009).
[h] Assuming sulfur content of 0.19 grains m^{-3} based on national standard (Haneke 2003).
[i] Emissions factors from U.S. EPA (2010) and available only for distillate fuel combustion units < 29 MW; assuming density of 835 kg m^{-3} (Curl and O'Donnell 1977).
[j] Assuming 0.0015% sulfur by weight (Miller and Ahmadi 2017).
[k] Based on value for low-sulfur diesel.
[l] Emissions factors from U.S. EPA (2010); assuming density of 846.9 kg m^{-3} (Wright et al. 2009).
[m] Emissions factors available only for units >29 MW.
[n] Emissions factors from U.S. EPA (2010); assuming density of 991.2 kg m^{-3} (Wright et al. 2009).
[o] Assuming 0.3% sulfur by weight (Miller and Ahmadi 2017).
[p] Based on value for residual oil.
[q] Emissions factors from U.S. EPA (1998b).
[r] Assuming density of 0.78 kg m^{-3} (Wright et al. 2009).
[s] Using value from natural gas.
[t] Assuming sulfur content of 0.07 grains m^{-3}.
[u] Emissions factors from U.S. EPA (1998c).
[v] Emissions factors from U.S. EPA (2003) and based on wood residue; emissions values displayed use mean HHV of 18.47 MJ kg^{-1} while simulated values consider range of HHV.

2.4.3 Other Impacts Not Quantified

We have carried out a qualitative analysis of other environmental impacts associated with the energy transition scenarios outlined here. These include impacts on land use, water resources and quality, terrestrial habitats and wetlands, and cultural and visual resources. Many of these impacts are highly site-specific and difficult to predict for hypothetical future projects (e.g., a potential future natural gas plant or wind farm). Quantification or monetization of these endpoints is unlikely to materially inform the policy process in comparison with the endpoints already monetized. This analysis is summarized in Table 10.

Table 7. Economic Valuations for Health Endpoints of Interest for Emission of Criteria Air Pollutants from Muller and Mendelsohn (2009)

Endpoint	Value (2009-USD)	Relevant pollutants
Mortality	1,980,000	$PM_{2.5}$, O_3
Chronic bronchitis	320,000	PM_{10}
Chronic asthma	30,800	O_3
Respiratory disease hospital admission	8,300	O_3
Cardiac disease hospital admission	17,526	SO_2
Asthma hospital admission	6,700	SO_2
COPD hospital admission	11,276	NO_2
Ischemic heart disease hospital admission	18,210	NO_2
Asthma emergency room visit	240	SO_2

2.5 Mathematical Modeling and Results Presentation

Quantitative modeling of economic and environmental endpoints for all scenarios was carried out in the R programming language (R Core Team 2017) within the RStudio integrated development environment (IDE) (RStudio PBC 2020). Uncertainty was represented using Monte Carlo simulations (10,000 trials). Confidence intervals around differences (e.g., difference in net cost between two scenarios) account for the large correlations in uncertainties across scenarios. This produces information on comparative cost-effectiveness (e.g., differences in costs) with overall narrower uncertainties than individual scenarios (e.g., absolute magnitude of costs) (Reichert and Borsuk 2005). Figures were generated in R, QGIS (QGIS.org 2018), and Adobe Illustrator (Adobe Inc. 2020) using the RColorBrewer package (Brewer et al. 2003, Neuwirth 2015).

Table 8. Social Costs of Emissions of Certain Criteria Air Pollutants by County

	Social cost (2019-USD $tonne^{-1}$)[a]			
New York	**SO_x**[b]	**NO_x**[c]	**$PM_{2.5}$**	**PM_{10}**
Albany	1,179–1,530	70–238	2,234–4,002	337–615
Allegany	1,616–1742	155–250	1,989–2,478	284–348
Bronx	3,862–8,658	**-1,440**–1,521	14,734–37,409	2,020–5,182
Broome	1,521–1,695	134–310	2,362–3,259	341–469
Cattaraugus	1,749–2,209	148–269	2,611–4,399	361–590
Cayuga	1,347–1,661	108–284	2,040–3,718	295–528
Chautauqua	1,573–1,708	150–269	1,802–2,329	259–332
Clinton	661–671	47–148	761–1,010	119–160
Columbia	1,200–1527	87–270	2,247–3,400	329–490
Delaware	1,577–1,816	152–302	2,502–3,245	367–481
Dutchess	1,427–2,149	152–299	3,078–5,485	446–788
Erie	1,582–2,095	143–295	2,462–5,124	344–691
Essex	773–834	49–139	1,012–1,312	159–210
Franklin	744–766	51–166	843–1,042	129–160
Fulton	1,095–1,223	76–227	1,632–2,323	243–343
Genesee	1,379–1,556	155–265	1,896–2,938	278–433
Greene	1,269–1,610	94–250	2,319–3,698	342–553
Hamilton	946–1,007	64–157	1,218–1,491	184–225
Herkimer	1,145–1,317	82–193	1,602–2,238	235–323
Jefferson	1,009–1,081	78–192	1,173–1,560	170–215
Kings	6,088–1,6692	**-4,257**–3,857	25,066–74,881	4,103–12,62
Lewis	1,032–1,128	77–162	1,286–1,698	189–236
Livingston	1,450–1,683	180–272	1,952–2,928	285–429
Madison	1,331–1,532	109–239	1,981–3,077	286–435
Monroe	1,332–1,717	117–268	2,046–4,192	293–591
Nassau	4,988–13,400	**-1,759**–2,192	19,958–58,049	2,675–7,654
New York	4,566–10,694	**-3,212**–2,057	17,332–45,402	2,459–6,559
Niagara	1,261–1,472	122–269	1,267–2,729	185–374
Oneida	1,254–1,434	99–208	1,708–2,516	249–358
Onondaga	1,416–1,766	112–274	2,176–3,816	314–542
Ontario	1,401–1,615	161–280	1,911–2,824	278–407
Orange	2,261–3,915	261–547	5,472–10,348	767–1,429
Orleans	1,256–1,372	139–268	1,534–2,277	224–333

New York	Social cost (2019-USD tonne^{-1})[a]			
	SO_x[b]	NO_x[c]	$PM_{2.5}$	PM_{10}
Oswego	1,139–1,671	96–3145	1,187–3,399	174–482
Otsego	1,327–1,457	114–236	1,913–2,440	283–366
Queens	1,724–21,858	**-5,848**–5,093	4,960–100,215	665–16,202
Rensselaer	1,151–1,502	67–249	2,212–3,687	332–542
Richmond	2,313–6,538	**-496**–1,156	6,952–24,318	1,008–3,707
Rockland	1,093–5,779	**-774**–1,061	2,661–16,776	374–2,509
Saint Lawrence	1,285–1,382	111–221	1,223–1,489	178–216
Saratoga	1,069–1,339	63–228	1,758–2,907	264–435
Schoharie	1,268–1,540	91–205	2,263–3,365	339–510
Seneca	1,365–1,451	118–315	1,825–2,407	266–350
Steuben	1,641–1,902	173–287	2,218–3,033	317–431
Suffolk	733–2,381	61–270	967–7,534	144–913
Sullivan	1,776–2,283	182–325	3,528–5,211	509–754
Tompkins	1,471–1,582	124–288	1,996–2,706	297–411
Ulster	1,548–2,094	149–295	2,996–4,598	428–654
Warren	928–1,041	58–181	1,282–1,770	195–267
Washington	936–1,081	59–185	1,411–2,012	216–307
Wayne	1,214–1,306	106–292	1,491–2,023	218–294
Westchester	2,766–6,194	**-1,799**–972	8,735–21,905	1,257–3,155
Wyoming	1,499–1,691	179–253	1,963–2,785	286–409
Yates	1,459–1627	156–262	1,988–2,860	288–410
New Jersey	Social cost (2019-USD tonne^{-1})[a]			
	SO_x[b]	NO_x[c]	$PM_{2.5}$	PM_{10}
Bergen	6,893–15,791	**-1,712**–3528	4,900–55,748	4,049–9,456
Hudson	1,599–11,524	**-686**–2,456	16,913–37,895	606–7,773
Union	4,427–8,843	84–1,748	30,726–70,806	2,291–5,126
Pennsylvania	Social cost (2019-USD tonne^{-1})[a]			
	SO_x[b]	NO_x[c]	$PM_{2.5}$	PM_{10}
Armstrong	1,754–2,195	178–284	2,161–4,066	274–511

[a] Uniform distribution based on ranges derived by pooling stack heights (low and tall point sources) from Muller and Mendelsohn (2009). Counties listed are those where NYISO reports generating assets including in New Jersey (considered part of Zones G and J) and Pennsylvania (considered part of Zone C).
[b] Using SO_2 values.
[c] Negative values are **in bold** and correspond to net benefits of reduced O_3 and/or PM due to NO_x titration in industrialized regions (Lei and Wang 2014)

Table 9. Social Costs Reported in the Literature for Carbon Monoxide (CO) Emissions

Social cost of emitted CO (2019-USD tonne^{-1})	Original units	Context	Reference
346	2005-CAD tonne^{-1}	Marginal damage of vehicle-related emissions in Vancouver, Canada	Litman and Doherty (2009)[a]
4–55	2002-AUD tonne^{-1}	Average damage of vehicle-related emissions in Australia (urban areas)	Beer (2002)[a,b]
2–1,558	1992-USD tonne^{-1}	Various in USA and Europe	Matthews and Lave (2000)[a]
1,982	1990-USD tonne^{-1}	Marginal damage of emissions in California	McPherson et al. (1994)[a]

[a] Secondary reference.

[b] Values of 26 and 55 in reported for secondary references; de novo analysis reports 4–20 (converted to 2019-USD per tonne).

Table 10. Qualitative Description of Environmental Impacts Not Quantified

Impact type	Technology and relevant scenarios			
	Existing facilities (A)	**CHPE[a] (B, C2, D2)**	**New natural gas[b] (C1, C2)**	**New solar[c] and offshore wind[d] (D1, D2)**
Land Use	No new land use changes expected.	Potential for temporary, non-significant disruptions to use of land and waterbodies during construction. The transmission line will traverse approximately 100 miles of the Lake Champlain riverbed, 130 miles of railroad right-of-way, 80 miles in the Hudson River, 6 miles in the Harlem River, and several miles underground along other routes. These areas constitute the *construction footprint*. Additionally, 4.5 acres would be permanently occupied by a converter station and 16 cooling stations. This area constitutes the permanent *site footprint*.	Localized permanent impacts on zoning and land use within a one-mile radius of the sites. Equivalent power delivery to CHPE could be achieved by a plant with nameplate capacity between 1,000–1,800 MW. This would require a total of about 200 to 400 acres of land. The energy facility physical footprint would require about 50 to 120 acres.	Wind or solar power delivery equivalent to CHPE would require substantially more installed capacity because of intermittency (see relatively low capacity factors in Table 4). Although the exact values are uncertain and depend on specific design choices, we use 3,000 MW and 5,000 MW as reference values for wind and solar respectively. Wind: 3,000 MW of offshore wind would require approximately 300,000 acres of ocean lease space. There is also the potential for limited impacts on nearby land use patterns and existing coastal infrastructure. Solar: 5,000 MW of utility scale solar would require approximately 28,000 acres of land.

Impact type	Technology and relevant scenarios			
	Existing facilities (A)	**CHPE[a] (B, C2, D2)**	**New natural gas[b] (C1, C2)**	**New solar[c] and offshore wind[d] (D1, D2)**
Transportation and Traffic	No new impacts expected.	Potential for temporary, non-significant disruptions during construction of waterway navigation, railroad operations, and traffic flow.	Potential for temporary moderate traffic increases during peak construction months. Expected to scale with site footprint.	Wind: Temporary impacts during construction on vessel traffic and recreational boating. The presence of wind turbine generators may increase risks to navigation and affect navigation routes, which are expected to scale with site footprint. Wind and solar: Potential for temporary, non-significant impacts to railroad operations and traffic flow during construction. Both expected to scale with construction site footprint.
Water Resources and Quality	Incremental increases to existing impacts on aquatic endpoints such as temperature (local only) and mercury deposition (local, regional, and global). Expected to scale with increased generation.	Localized, non-significant water quality impacts associated with construction.	Demands on surface water and/or groundwater for site operations such as cooling; demands on wastewater infrastructure. Expected to scale with added generation.	Wind and Solar: Short term, localized impacts to water resources and quality during construction. Both expected to scale with construction footprint.

Impact type	Technology and relevant scenarios			
	Existing facilities (A)	**CHPE[a] (B, C2, D2)**	**New natural gas[b] (C1, C2)**	**New solar[c] and offshore wind[d] (D1, D2)**
Aquatic Protected and Sensitive Species	Incremental increases in existing impacts as above. We are not aware of individual species jeopardized by existing power plants.	Localized, non-significant effects on individuals among federally listed and state-listed species, including sturgeon during construction and long-term operations and maintenance.	These impacts are highly site-specific; general statement not possible. We did not identify adverse impacts in the references we reviewed.	Solar: No new impacts expected. Wind: Potential short- and long-term impacts on federally listed endangered and threatened species. Expected to scale with site footprint.
Terrestrial Habitats and Species	No new impacts expected.	Permanent conversion of approximately 48 acres (19 hectares) of fringe forest habitat to scrub/shrub habitat.	Localized displacement of wildlife that currently utilize the site. Expected to scale with site footprint.	Wind: Short term and/or localized impacts to terrestrial fauna. Solar: May fragment or eliminate species habitat. Both expected to scale with site footprint.
Terrestrial Protected and Sensitive Species	No new impacts expected.	Conversion and disturbance of fringe forest habitat may affect, but is not likely to adversely affect, federally listed and state-listed species.	These impacts are highly site-specific; general statement not possible. We did not identify adverse impacts in the references we reviewed.	Wind: Short term and/or localized impacts to terrestrial fauna. Solar: May have significant impacts on threatened and endangered species, which may be avoided when siting project.
Public Health and Safety	No new impacts expected.	Occupational hazards associated with new construction.	Occupational hazards associated with new construction. Expected to scale with site footprint.	Occupational hazards associated with new construction expected to scale with construction footprint.

Impact type	Technology and relevant scenarios			
	Existing facilities (A)	**CHPE[a] (B, C2, D2)**	**New natural gas[b] (C1, C2)**	**New solar[c] and offshore wind[d] (D1, D2)**
Wetlands	No new impacts expected.	Significant, permanent change of 10.2 acres (4.1 hectares) of wetlands. To mitigate for permanent impacts, 1 acre of new wetland would be established, and 10 acres of existing wetland would be preserved and enhanced for each acre of permanently impacted wetlands.	These impacts are highly site-specific; general statement not possible. In some cases (e.g., TRC 2009), significant, permanent changes to wetlands are mitigated with a wetland replacement ratio greater than 1.	Wind: No new impacts expected. Solar: May have significant impacts on wetlands. These impacts may be avoided when siting the project.
Geology and Soils	No new impacts expected.	Temporary disturbance of soil and sediment.	No new impacts to geological resources expected during operations. Excavation and stockpiling may result in the permanent loss of agricultural soil resources. Expected to scale with site footprint.	Wind: Short-term, localized impacts on geological resources. Solar: Short-term, localized impacts if existing site grade is maintained. Both expected to scale with construction footprint.
Cultural Resources	No new impacts expected.	Potential adverse effects on 90+ archaeological or historic sites, to be managed through a Programmatic Agreement with the New York State Historic Preservation Officer.	These impacts are highly site-specific; general statement not possible. Expected to scale with site footprint.	Wind: Onshore export cable routes may run through or adjacent to known archeological sites. Solar: Impacts may be avoided when siting the project.

Impact type	Technology and relevant scenarios			
	Existing facilities (A)	CHPE[a] (B, C2, D2)	New natural gas[b] (C1, C2)	New solar[c] and offshore wind[d] (D1, D2)
Visual Resources	No new impacts expected.	Non-significant effects on visual resources.	These impacts are highly site-specific; general statement not possible. In the case of CPV (TRC 2009), non-significant effects on visual resources were anticipated and minimized by the addition of natural vegetation and landscaping. Expected to scale with site footprint.	Wind: Nearby coastlines may leave limited visibility of wind turbine generators when weather conditions allow. At distances greater than 14 miles (23 km) the turbines will likely be considered visually subordinate to the overall landscape. The visual impact of turbines to historic properties varies by location. Solar: The visual impact of solar installations varies greatly by location.
Infrastructure	No new impacts expected.	Non-significant negative impacts on infrastructure. Increased reliability and capacity of electricity provision compared to Scenario A.	These impacts are highly site-specific; general statement not possible. We did not identify adverse impacts in the references we reviewed. We expect increased reliability and capacity of electricity provision compared to Scenario A.	Wind: Potential for limited impacts on nearby land use patterns and existing coastal infrastructure. Solar: No new impacts expected. Increased grid reliability compared to Scenario A will only be achieved after significant expansion of capacity.

Impact type	Technology and relevant scenarios			
	Existing facilities (A)	CHPE[a] (B, C2, D2)	New natural gas[b] (C1, C2)	New solar[c] and offshore wind[d] (D1, D2)
Recreation	No new impacts expected.	Temporary, non-significant limits on access during construction and maintenance.	These impacts are highly site-specific, general statement not possible. We did not identify adverse impacts in the references we reviewed.	Wind: Localized and temporary impacts on shoreline fishing activities and access to the landfill site. Solar: No new impacts expected.
Hazardous Materials and Wastes	Incremental increases in existing impacts such as the volume of waste products to be removed. Expected to scale with increased generation.	Limited amounts of oils, solvents, antifreeze, and other hazardous materials generated from routine maintenance and inspections. Construction activities require use of oils, fuels, and other hazardous materials.	Construction and operation of a natural gas plant involves substantial handling and disposal of hazardous materials such as natural gas, backup fuel oil, lube oils, hydrogen, water treatment chemicals, and aqueous ammonia. Expected to scale with added generation.	Construction activities require use of oils, fuels, and other hazardous materials. Expected to scale with construction footprint.

Impact type	Technology and relevant scenarios			
	Existing facilities (A)	**CHPE[a] (B, C2, D2)**	**New natural gas[b] (C1, C2)**	**New solar[c] and offshore wind[d] (D1, D2)**
Air Quality	Incremental increases in existing impacts; the value of these impacts is characterized quantitatively in this study.	Localized, intermittent impacts from use of construction and maintenance equipment, particularly from vehicle exhaust, fugitive dust, and GHG emissions. The impact of CHPE on total air emissions is characterized quantitatively in this study.	Operation of a natural gas plant results in emissions of NO_x, VOC, CO, SO_2, PM_{10}, $PM_{2.5}$, H_2SO_4, and greenhouse gases. Release of air pollutants may be managed with pollution control equipment. The impact of developing a new natural gas plant on total air emissions is characterized quantitatively in this study. Expected to scale with added generation.	Temporary, localized air quality impacts associated with construction activities. Expected to scale with construction footprint.
Socio-economics	No new impacts expected.	Local employment and spending are characterized quantitatively in this study.	Local employment and spending are characterized quantitatively in this study.	Local employment and spending are characterized quantitatively in this study.
Noise	No new impacts expected.	Temporary, localized noise impacts from construction and maintenance.	Temporary, localized noise impacts from construction and maintenance. Expected to scale with site footprint.	Wind: Temporary impacts from the noise generated from pile driving during the construction phase. Minimal impacts from noise generated during operation. Expected to scale with site footprint. Solar: Non-significant impacts on noise.

Impact type	Technology and relevant scenarios			
	Existing facilities (A)	CHPE[a] (B, C2, D2)	New natural gas[b] (C1, C2)	New solar[c] and offshore wind[d] (D1, D2)
Environmental Justice	Existing power plants are disproportionately sited in proximity to minority and low-income populations.	No disproportionate human health or environmental effects on minority or low-income populations.	These impacts are highly site-specific; general statement not possible.	Unlikely to have disproportionate adverse impacts on low-income or minority populations.

[a] Impacts summarized from U.S. DOE (2014).
[b] Impacts summarized from CVEC (2012) and TRC (2009).
[c] Impacts summarized from VHB Engineering (2017).
[d] Impacts summarized from Epsilon Associates Inc. (2018) and NYSERDA (2018).

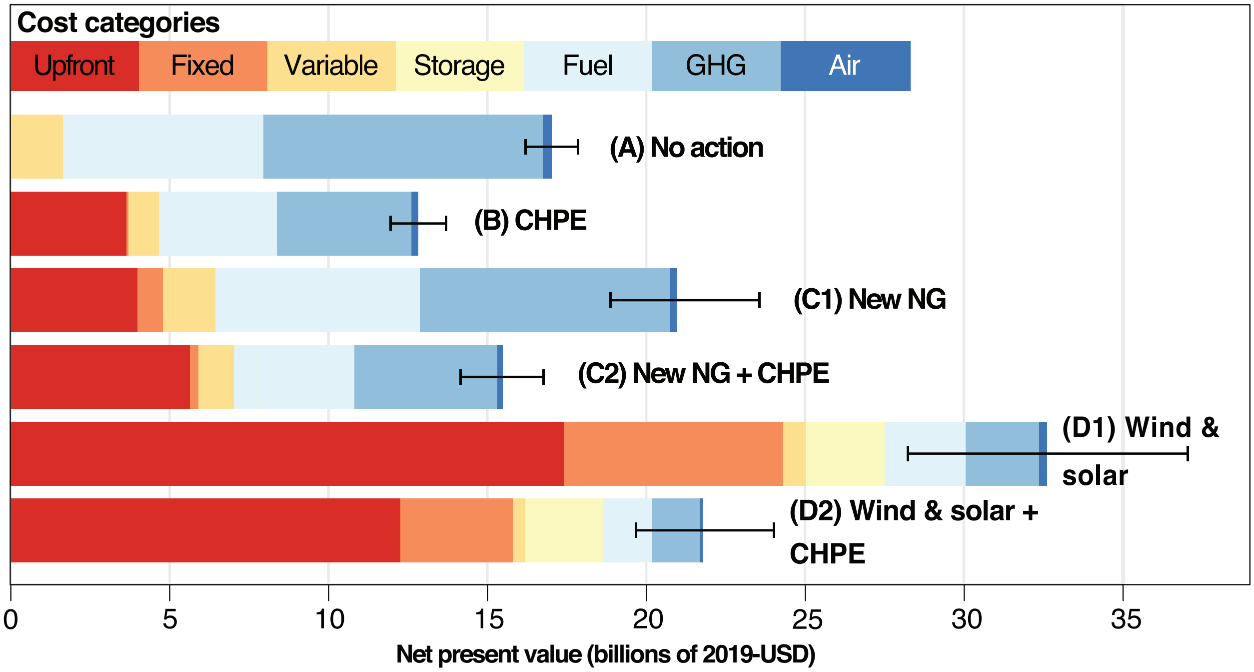
3. RESULTS

3.1 Summary of Overall Net Costs

Closure of IPEC, in the absence of additional Downstate generation capacity (Scenario A), creates roughly $16.9 billion (90% CI: $16.1–$17.7 billion) in additional operational expenses and environmental impacts in the period 2021–2050. These values assume that existing natural gas generators can produce the full 15,304 GW·h per year formerly produced by IPEC and do not consider potential additional generation by fuel oil generators (which are associated with higher costs). These excess costs are primarily attributable to increased fuel costs (37% of total costs, 90% CI: 35–40%) and GHG emissions (52% of total costs, 90% CI: 50–55%). For comparison, the operation of Indian Point through 2050 may have represented roughly $4.7 billion in fixed, variable and fuel costs (NREL 2019a).

Total costs associated with development of a new natural gas generator (Scenario C1) and future-build out of Downstate solar and offshore wind capacity (Scenario D1) are roughly 21% (90% CI: 10–36%) and 93% (90% CI: 66–119%) higher than those for Scenario A, respectively. In those scenarios, higher upfront costs are partially offset by avoided greenhouse gas emissions and operational expenses over the analysis period. Total added costs beyond Scenario A, however, are $3.7 billion (90% CI: $1.7–$6.1billion) for new natural gas generation (Scenario C1) and $15.6 billion (90% CI: $11.3–$20.1 billion) for future build-out of offshore wind and solar capacity (Scenario D1) in the period 2021–2050 (counting only that build-out which is necessary to compensate for the loss of IPEC). We note that the apparent cost-effectiveness of future-build out of offshore wind and solar relative to no-action (Scenario A) is sensitive to the timeframe considered and the values used for social cost of carbon (SCC). We explore this in Section 3.8.3.

Figure 6. Net Present Value of Costs Incurred by Scenario over the Period 2021–2050 (as Defined in Section 2.1.1) and Cost Category



Note. Error bars denote 90% confidence interval around total.

Development of CHPE reduces net costs assuming no other action and improves the cost-effectiveness of new natural gas generation and future build-out of Downstate offshore wind and solar resources. Development of CHPE only (Scenario B) reduces net costs by $4.2 billion (90% CI: $3.4–$4.9 billion) assuming no other action (Scenario A) in the period 2021–2050. This takes account of the likely upfront costs associated with CHPE ($3.7 billion, 90% CI: $3.0–$4.3 billion). Assuming development of new natural gas generation, CHPE reduces net costs by $5.4 billion (90% CI: $4.0–$6.9 billion) (Scenario C2 vs. Scenario C1) by reducing the size of the plant required and by avoiding GHG emissions before development and during operation. Assuming forecasted build-out of offshore wind and solar generation, CHPE reduces net costs by $10.8 billion (90% CI $8.4–$13.1 billion) (Scenario D2 vs. Scenario D1) due to earlier displacement of GHG and reduced capital expenditures necessary to compensate for the loss of IPEC.

Table 11. Net Present Value of Direct and Indirect Costs (Billions of 2019-USD)[a]

Impact type	Scenario: No action (A)	CHPE (B)	New NG (C1)	New NG + CHPE (C2)	Offshore wind & solar (D1)	Offshore wind & solar + CHPE (D2)
Upfront	0	3.7 (3.0–4.4)	4.2 (2.4–6.5)	5.6 (4.5–6.8)	17.4 (13.9–21.0)	12.3 (10.4–14.2)
Fixed	0	0.1 (0.0–0.1)	0.8 (0.4–1.2)	0.4 (0.2–0.6)	7.0 (5.9–8.2)	3.5 (3.0–4.1)
Variable	1.6 (1.1–2.2)	1.0 (0.6–1.3)	1.6 (1.1–2.2)	1.0 (0.6–1.3)	0.6 (0.4–1.0)	0.4 (0.2–0.6)
Battery storage	0	0	0	0	2.5 (2.3–2.7)	2.5 (2.3–2.7)
Fuel	6.3 (5.9–6.8)	3.7 (3.4–4.0)	6.3 (5.9–6.8)	3.8 (3.5–4.3)	2.5 (1.8–3.4)	1.5 (1.2–2.0)
GHG	8.8 (8.8–8.8)	4.3 (4.3–4.3)	7.5 (7.5–7.5)	4.3 (4.3–4.3)	2.5 (2.0–3.4)	1.6 (1.4–2.0)
Air quality	0.130 (0.054–0.206)	0.063 (0.023–0.104)	0.087 (-0.054–0.284)	0.064 (0.03–0.097)	0.044 (0.018–0.075)	0.029 (0.012–0.047)
Total	16.9 (16.1–17.8)	12.8 (12.0–13.6)	20.6 (18.5–23.1)	15.2 (13.9–16.5)	32.6 (28.2–37.0)	21.8 (19.7–24.0)

[a] Mean estimate (90% confidence interval); negative values for air quality impacts are in bold and correspond to possible countervailing benefits of reduced O_3 and/or PM due to NO_X titration (Lei and Wang 2014).

CHPE represents substantial upfront expenditures for all scenarios of which it is a part, but these expenditures are outweighed by avoided GHG emissions and lower variable costs over the period of analysis. In the case of the development of new natural gas generation, CHPE allows for a smaller gas plant: upfront costs assuming CHPE in conjunction with new natural gas generation (Scenario C2) are only $1.4 billion greater than with the natural gas plant alone (90% CI: $0.0–$2.7 billion), compared to $3.7 billion for CHPE alone (90% CI: $3.1–$4.4 billion; Scenario B). When considering future build-out of Downstate renewables, added upfront expenses associated with CHPE are offset by reduced GHG emissions during the years over which this build-out is occurring. In the period 2021–2050, developing CHPE in conjunction with build-out of renewables avoids $914.0 million (90% CI: $587.8 million–$1.4 billion) in GHG emissions compared with build-out of renewables alone (Scenario D2 vs. D1). A breakdown of total costs is provided for each scenario in Table 11 and illustrated in Figure 6. Details for each cost category are provided in the following sections.

3.2 Upfront and Fixed Costs

For scenarios that include new generation or transmission capacity, we considered costs related to upfront investment and ongoing maintenance, which do not vary with the amount of power delivered. We did not consider such costs for facilities that would exist regardless of decisions taken in this context. Therefore, upfront and fixed costs for Scenario A (no action) are null.

Upfront costs associated with CHPE (Scenario B) are calculated as $3.7 billion in 2019-USD (90% CI: $3.0–$4.4 billion) based on a uniform distribution spanning available estimates (PA Consulting Group 2017, TDI et al. 2020). Annual fixed costs were assumed equal to 0.1% of capital costs based on NREL (2016). Upfront costs payable in 2021 and fixed costs payable between 2025–2050 total $3.8 billion (90% CI: $3.1–$4.4 billion) in 2019-USD.

Upfront and fixed costs associated with new natural gas generation alone (Scenario C1) total $5.0 billion ($3.0–$7.5 billion). Relatively large uncertainties here are attributable to the wide range of plausible capacity factors for a future gas generator (51–87%; see Table 4). We note that the capacity factors retained here are based on NREL (2019a) and are higher than the real utilization factors in New York State (29% statewide and 28% Downstate in 2019) (NYISO 2020a). Construction of a natural gas plant to replace IPEC with a 29% capacity factor would result in upfront and fixed costs totaling $11.5 billion (90% CI: $7.8–$15.2 billion) over the period 2021–2050, during which power would be delivered as of 2029.

Building CHPE in conjunction with new natural gas generation (Scenario C2) decreases the installed capacity of natural gas necessary to replace IPEC by 1,407 MW (90% CI: 1,114–1,798 MW). Therefore, the fixed costs of building CHPE and new natural gas are lower than either alternative alone. Over the period 2021–2050, Scenario C2 fixed and upfront costs total $6.0 billion (90% CI: $4.9–$7.3 billion) where CHPE would deliver first power at the start of 2025 and new natural gas would deliver first power at the start of 2029.

For the purposes of this analysis and to facilitate comparison with other scenarios, we calculate costs and benefits with added renewables capacity (Scenarios D1 and D2) up to the amount that replaces the generation formerly provided by IPEC. In Scenario D1 (wind and solar), all build-out of utility and wind and solar up to the statewide target of 6,000 MW is counted (achieved in 2027) while build-out of wind is counted through 2030. In Scenario D2 (wind and solar + CHPE), less renewables are needed to compensate for the loss of IPEC. Here, solar and wind build-out are counted through 2025.

In Scenario D1 (wind and solar only), upfront and fixed costs total $24.4 billion (90% CI: $20.6–$28.3 billion). Adding CHPE to this plan (Scenario D2) decreases total upfront costs by $8.6 billion (90% CI: $6.5–$10.8 billion). This is because less build-out of renewables is necessary to compensate for the loss of IPEC when coupled with CHPE; the savings in renewables build-out outweigh the added cost of CHPE.

3.3 Variable and Fuel Costs

Variable and fuel costs are calculated for power generation under all scenarios. Variable and fuel costs associated with using existing natural gas generation assets to produce the 15,304 GW·h per year of power formerly generated by IPEC (Scenario A) total $8.0 billion (90% CI: $7.2–$8.8 billion) over the period 2021–2050. Assuming new natural gas generation to replace IPEC (Scenario C1) results in identical variable and fuel costs as Scenario A.

Variable and fuel costs associated with future build-out of renewable generation (Scenario D1) add up to $3.1 billion ($90% CI: $2.3–$4.3 billion). These costs are entirely attributable to gas generation during the years during build-up to the former output of IPEC, as we considered offshore wind and solar generation to have zero fuel and variable costs (Table 4 and Table 5). Likewise, we consider CHPE to have zero variable and fuel costs. Assuming that CHPE is built with no other action (Scenario B), fuel and variable costs total $4.6 billion (90% CI: $4.2–$5.1 billion), attributable to the natural gas generation that makes up the difference between CHPE and IPEC.

Coupling CHPE with new natural gas generation (Scenario C2) or build-out of Downstate offshore wind and solar (Scenario D2) reduces total variable and fuel costs because it displaces gas generation as of 2025. Variable and fuel costs assuming CHPE in conjunction with new natural gas generation (Scenario C2) are $3.2 billion (90% CI: $2.9–$3.5 billion) lower than new natural gas generation alone (Scenario C1). Variable and fuel costs assuming CHPE in conjunction with future build-out of Downstate offshore wind and solar (Scenario D2) are $1.2 billion (90% CI: $0.8–$1.8 billion) less than build-out of Downstate offshore wind and solar alone (Scenario D1).

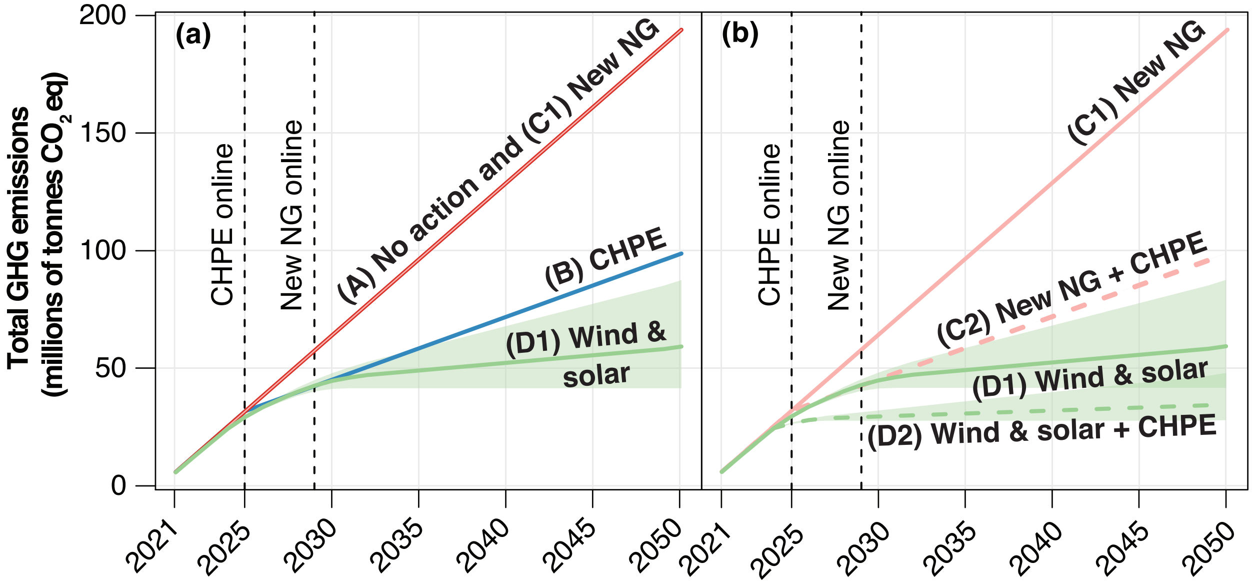
3.4 Climate Impacts

The economic valuation of GHG emissions plays a major role in the comparative cost-effectiveness of each scenario evaluated. Figure 7 plots total GHG emissions over time for the scenarios evaluated. These emissions are calculated for excess generation attributable to the closure of IPEC. Figure 7(a) displays GHG emissions for individual technological interventions with the associated scenarios and Figure 7(b) displays the effect of adding CHPE to new natural gas generation (Scenario C2 vs. C1) and build-out of wind and solar (Scenario D2 vs. D1).

In Scenario A (no action), emissions associated with the closure of IPEC continue indefinitely in proportion to the annual emissions of local gas generating facilities, which are assumed to account for the difference. By 2050, total GHG emissions reach 190.8 million tonnes CO_2 equivalents. These GHG emissions are calculated by assuming that the most efficient natural gas generators would preferentially supply power formerly delivered by IPEC as described in Section 2.1.1. The use of default emissions factors displayed in Table 5 returns values that are similar but slightly higher. Therefore, for Scenario C1 and C2 we assume that GHG emissions on a per-kW·h basis would equal those in Scenario A (a new generator would be as efficient as the most efficient existing generators). Therefore, development of a new natural gas generator alone (Scenario C1) would have the same forecasted GHG emissions.

Developing CHPE alone (Scenario B) displaces fossil fuel generation Downstate, and therefore annual GHG emissions decrease when it starts delivering power (counted as of 2025 in our analysis). By 2050, Scenario B avoids 96.2 million tonnes CO_2 equivalents compared to Scenario A. Previously, PA Consulting Group (2017) had estimated that CHPE would avoid 3.4 million tonnes of CO_2 per year, or roughly 85 million tonnes between 2025–2050. This is similar to the value we calculate. Differences may be attributable to the use of different emissions factors.

Figure 7. Cumulative GHG Emissions in CO_2 Equivalents over Time for (A) Discrete Intervention Scenarios and (B) Scenarios in which CHPE Is Coupled with Another Intervention (Hatched Lines) vs. the Corresponding Scenario in which CHPE Is Not Included (Solid Lines)



Note. Emissions calculated from generation required to replace the output of IPEC (15,304 GW·h per year). After 2025 (Scenario D2) or 2030 (Scenario D1) expected output from renewables equals the output formerly supplied by IPEC (15,304 GW·h per year). Shaded areas are 90% confidence intervals.

For scenarios involving the continuous build-out of Downstate offshore wind and solar, total emissions flatten out over several years as the generation attributable to IPEC is fully replaced. This assumes that generation from IPEC can be replaced by offshore wind and solar while maintaining reliability requirements. By 2050, emission associated with Scenario D1 (wind and solar only) reach 58.2 million tonnes CO_2 equivalents (90% CI: 41.3–86.2 million tonnes). This is attributable to fossil fuel generation occurring during build-out of wind and solar and to the uncertain potential contribution of fossil-fuel generation even at the target build-out of renewables as described in Section 2.1.4.

We note that overall expected build-out of wind generation in New York State exceeds what is considered here and will eventually far outweigh the generation formerly provided by IPEC (Section 2.1.4). In the long run, this additional build-out will more than compensate for the emissions calculated here. However, as described in Section 2.1.4, we consider here only build-out of wind and solar up to the point at which it is greater than 50% likely that the generation formerly supplied by IPEC has been replaced by wind and solar (Scenario D1) and/or CHPE (Scenario D2). This facilitates comparison with other scenarios.

Coupling CHPE with new natural gas (Scenario C2) or build-out of wind and solar (Scenario D1) results in reduced GHG emissions compared to either of these two interventions without CHPE (Scenario C1 or D1). This is because CHPE displaces additional GHG emissions as of 2025. By 2050, Scenario C2 avoids a further 82.3 million tonnes CO_2 equivalents compared to Scenario C1, while Scenario D2 avoids a further 23.6 million tonnes CO_2 equivalents (90% CI: 13.4–38.2 million tonnes) compared to Scenario D1. Scenario D2 (CHPE + build-out of wind and solar) minimizes overall GHG emissions compared to any other scenario evaluated here.

Economic valuation accounts for the time differences of emissions and allows scenarios to be compared in terms of net present value following the methodology of the Interagency Working Group on Social Cost of Greenhouse Gases (2016), which NYISO has proposed to adopt (Section 2.4.1). GHG emissions associated with no-action Scenario A are valued at $8.8 billion over the period 2021–2050 assuming a discount rate of 3% discount rate in line with current NYISO proposals for valuing GHG emissions (Section 2.4.1). Conversely, GHG emissions associated with Scenario D2 (CHPE + wind and solar) are valued at $1.6 billion (90% CI: $1.4–2.0 billion) over the same period. Economic valuations of GHG emissions for all scenarios are tabulated in Table 11.

3.5 Air Quality Impacts

All scenarios are associated with atmospheric pollutant emissions. In Scenario A (no action), these emissions are assumed to remain constant over the study period. In other scenarios, annual emissions change over time as new technologies start delivering power, displacing generation from existing facilities. For example, CHPE (Scenarios B, C2, D2) displaces existing local generation as of 2025, and new natural gas (Scenarios C1, C2) displaces existing local generation as of 2029. Offshore wind and solar (Scenarios D1, D2) displace increasing amounts of existing local generation each year up to the point at which generation formerly supplied by IPEC has been replaced. Table 12 summarizes the annual air emissions for each Scenario at the end of the period of analysis (year 2050).

Economic valuation of these impacts resolves the time differences and calculates a net present value for each scenario. Compared to other categories of costs and impacts quantified, the economic impacts of local air pollution are relatively small. The net present value of impacts in the period 2021–2050 totals $130.1 million (90% CI: $54.1–$206.0 million) in no-action Scenario A. Development of CHPE (Scenario B) reduces this by $119.3 million (90% CI: $64.9–$178.1 million). Development of a new natural gas facility (Scenario C1) reduces the value of air emissions compared to Scenario A by an expected $43.1 million due to the slightly lower default air emissions factors used for new generators (Table 6) as compared to the historic data from U.S. EPA's eGRID for existing facilities, making the assumption that future emissions with a new natural gas generator will not be greater than real emissions of legacy generators (Section 2.4). The 90% CI of this difference is very wide (90% CI: $-39.2–$190.6 million) and is greater than the range of possible impacts from no-action Scenario A. This is because of the uncertainty in the power generated by a future gas plant and the possibility that it would generate more power than what has been lost from IPEC.

Coupling CHPE with either new natural gas (Scenario C2) or build-out of Downstate offshore wind and solar (Scenario D2) is likely to reduce air emissions impacts relative to the corresponding scenario without CHPE (Scenario C1 for natural gas and Scenario D1 for offshore wind and solar). Scenario C2 reduces net present value of air emissions by $23.5 million (90% CI: -$139.2–$91.1 million) compared to Scenario C1, and Scenario D2 reduces net present value by $15.3 million (90% CI: $4.8–$30.5 million) compared to Scenario D1. This is because of increased displaced emissions during build-out of wind and solar.

Table 12. Eventual Annual Atmospheric Emissions Attributable to IPEC Closure (Tonnes per Year)[a]

Scenario[b]	Pollutant			
	SO_x	NO_x	$PM_{2.5}$[a]	CO
(A) No action	460.3 (460.1–460.6)	2,823 (2,715.9–2,938)	21.1 (19.6–22.7)	3,744.7 (3,477.5–4,031.2)
(B) CHPE as of 2025	59.7 (59.6–59.9)	613.3 (558.5–672.2)	9.6 (9.0–10.4)	1,708.5 (1,586.6–1,839.2)
(C1) New NG as of 2029	26.7 (24.8–28.8)	2,678.6 (2,678.6–2,678.6)	19.5 (19.5–19.5)	3,452.1 (3,452.1–3,452.1)
(C2) New NG + CHPE as of 2029	12.2 (11.3–13.1)	539.4 (539.4–539.4)	8.9 (8.9–8.9)	1,575 (1,575–1,575)
(D1) Offshore wind & solar as of 2029	16.3 (0.0–43.9)	245.2 (0.0–610.7)	3.7 (0.0–8.3)	652.9 (0.0–1,470.5)
(D2) Offshore wind & solar + CHPE as of 2025	12.7 (1.1–17.3)	133.5 (13.6–213)	2.5 (0.8–4.4)	450.5 (137.6–771.9)

[a] For natural gas generation, all particulate matter is assumed to be $PM_{2.5}$, so PM_{10} = $PM_{2.5}$; economic valuation considers $PM_{2.5}$ only.
[b] Emissions in Scenarios B, C1, C2, D1, and D2 change over time and years given are the earliest years for which reported emissions apply (earlier years are higher); in Scenarios D1 and D2, eventual emissions are the probability-weighted contributions of legacy generation even after it is >50% likely that IPEC generation has been replaced and the 90% confidence interval includes 0, i.e., no emissions attributable to this scenario.

The economic valuation of air emissions is a function of the density of the county in which the emissions occur (Table 8). We assigned generation to individual facilities based on the 2019 usage factor (ratio between energy supplied and rated nameplate capacity), where relatively underutilized facilities supplied more power in hypothetical future scenarios to account for the closure of IPEC (Section 2.1.1). The Cricket Valley Energy Center in Dover, NY (Zone G) was commissioned in 2018, has a total installed capacity of 1,177 MW and reported zero net generation in 2019 (NYISO 2020a, U.S. EPA 2020). Cricket Valley represents three natural gas generators out of a total of 92 Downstate yet accounted for roughly a quarter of the generation formerly supplied by IPEC. In a sensitivity analysis (Section 3.8.1), we assume that generation from IPEC is replaced by generating assets in the immediate vicinity of New York City only (i.e., Zones H, I, and J). That sensitivity analysis excludes Cricket Valley and other more distant generators and characterizes the upper bound of possible air quality impacts. We also consider the impact on air emissions if a broader range of technologies (i.e., including oil-fired generators) respond to the closure of IPEC (Section 3.8.2).

We monetized air quality impacts for each scenario to facilitate comparison across scenarios and other endpoints. These results are presented in Table 11. The economic valuations aggregate impacts of marginal emissions in each county and correspond overwhelmingly to impacts on human health (mortality and cardiovascular and respiratory disease cases and hospital admissions) as described in Section 2.4.2. The valuations of county-specific air quality impacts that we used (Table 8) reflect the valuations of health outcomes synthesized by Muller and Mendelsohn (2009). In some cases, these valuations are relatively conservative. For example, the value retained for premature mortality is $2.36 million in 2019-USD. In the past, the U.S. EPA has used values for a "statistical life" ranging from roughly $1–$15 million and now recommends a median estimate of $9.4 million (2019-USD) (U.S. EPA 2018).These economic valuations reflect the amount of money that different groups are willing to invest to avoid premature death of individuals facing environmental risks, on average, per death avoided.

We calculated the total economic value for these impacts to be on the order of hundreds of millions of dollars over the period of analysis (Table 11). The underlying value of health outcomes, e.g., premature mortality in the low millions of dollars, is consistent with health impacts on the order of hundreds of premature deaths over the period of analysis. This is a conservative assessment because it does not consider possible increased output of oil-fired peaker plants in response to the closure of IPEC. Decomposing overall economic valuations presented here into county-specific health outcomes requires compilation and execution of the underlying air quality and economic models. This exceeds the scope of the present analysis but could be the focus of future work.

Independently of this study, PA Consulting Group (2020) carried out an assessment of the impact of CHPE on criteria air pollutant emissions in the vicinity of New York City. Emissions reductions forecasted in that study are generally lower than we have described here (e.g., 505 tonnes NO_X and 52 tonnes SO_X compared to our approximately 2,209 tonnes NO_X and 401 tonnes SO_X). This is likely due to that study's focus on the immediate New York City area and use of an hourly dispatch model that provides realistic support for the contribution of peaker plants. By contrast, our main analysis considers gas plants only and evaluates the broader Downstate region (not just the New York City area). While our approach has the advantage of integrating multiple endpoints, it is likely that the characterization by PA Consulting Group provides a better assessment of air quality impacts in the immediate vicinity of New York City.

3.6 Local Economic Impacts

Table 13 summarizes the output of JEDI model runs for potential new infrastructure projects. We report local expenditures, local economic output and employment creation. For each of these, we report values for the construction phase and the operational phase separately. For local expenditures and economic output, we also calculate a net present value over a horizon of 30 years to account for time differences in the accrual of economic effects across technologies. We also report local expenditures as a fraction of overall direct costs associated with each project. To facilitate evaluation of the impacts attributable to each technology separately, we report discrete technologies and note the scenarios in which each applies.

For solar and offshore wind, we consider likely continuous build-out over the project horizon based on past trends and current published plans (Table 3) with both costs and benefits accruing over the model horizon. Operation-phase yearly values for solar and offshore wind are reported for the quantities of wind and solar required to compensate for the closure of IPEC in the absence of CHPE (Scenario D1); true build-out over the next 50 years is likely to be substantially greater.

Local upfront and recurring expenditures forecasted by JEDI account for a substantial portion of direct costs for all projects evaluated. This ranges from 28.7% (wind in Scenario D1) to 37.4% (solar, Scenario D1). Direct costs considered in this calculation are those described in Section 2.2 (upfront, fixed, variable, and fuel costs). Local expenditures accounted for by JEDI include costs of labor (wages), sales and property taxes and right of way royalties as well as the locally sourced fraction of project materials. Local economic output includes supply chain effects from project capital expenditures and induced demand increases from increased wages.

Offshore wind is associated with greater local expenditures, indirect economic output and job creation than any other technology studied. This is partially related to the fact that offshore wind and solar have overall greater direct upfront and fixed costs than other alternatives (Section 3.2). Utility solar is a relatively small part of the overall forecast for renewables expansion, so its economic impact is modest. However, it compares favorably on the basis of local fraction of all expenditures (37.4%). The economic impacts of solar are also likely underestimated because they do not include the role of distributed solar, which is driving overall solar increases in New York State, including Downstate (Section 2.1.4).

Scenario D2 (wind and solar + CHPE) assumes a smaller build-out of wind and solar than Scenario D1 (wind and solar alone) because the contribution of CHPE means less local renewable generation is required to replace IPEC (Section 2.1.4). Table 13 tabulates the local economic impact of discrete technologies assuming the build-out of wind and solar modeled in Scenario D1. In Scenario D2, the build-out required for wind and solar declines and so does the local economic impact. The sum of the local economic impact of the lesser wind and solar build-out together with CHPE is lower than wind and solar alone. For example, net present value of local economic impact for the lesser amount of wind and solar + CHPE is valued at $6.0 billion (90% CI: $5.2–$6.8 billion) compared to $9.5 billion (90% CI: $8.0–$11.1 billion) for wind and solar alone in Scenario D1. However, the total costs of Scenario D2 are also substantially lower than those in Scenario D1 (Section 3.1).

Table 13. JEDI Model Output for New Construction Projects[a]

Economic parameter	CHPE (B, C2, D2)	Natural gas (C1[c])	Offshore wind (D1[d])	Solar[b] (D1[d])
Construction-phase local expenditure (10^6 $)	502.9 (475.1–530.6)	1,266.5 (565.8–1,963.6)	5,294.9 (4,210.4–6,372.4)[e]	159.1[e]
Operation-phase local expenditure (10^6 $ year^{-1})	49.9 (47.7–52)	140.6 (60.9–222)	246.8 (204.2–290.4)[f]	3[f]
Local expenditures NPV (10^6 $)[g]	1,294.8 (1,247.2–1,341.7)	3,035.3 (1723.7–4340.3)	6,221.9 (5,158.4–7,291.2)	175
Fraction of direct costs as local expenditures (%)	34.9 (29.1–41.9)	31.3 (17–47.3)	28.7 (21.8–36.8)	37.4
Construction-phase economic output (10^6 $)	755 (728.9–780.8)	1,869 (831.3–2899.3)	7,442.6 (5,891.9–9,007.5)	262.4
Operation-phase economic output (10^6 $ year^{-1})	37.1 (35.8–38.4)	132.5 (60.8–204.3)	429.6 (352.8–507.6)	47.1
Economic output NPV (10^6 $)[g]	1,344.2 (1308.2–1380.3)	3,535.6 (2,035–4,995.3)	9,098.5 (7,546.3–10,670.2)	440.6
Construction-phase employment (FTE job-years)	5,871 (5,703–6,038)	8,535 (3,774–13,263)	29,974 (25,325–34,629)[e]	1,148[e]
Operation-phase employment (FTE jobs)	200 (193–206)	763 (364–1,159)	1,761 (1,478–2,044)[f]	533[f]

[a] Values reported assume a study period of 2021–2050 and correspond to mean (90% confidence interval); relevant scenarios are noted in parentheses.
[b] Concentrating solar power plants only and excluding distributed solar.
[c] Analysis carried out for a natural gas plant supplying 15,304 GW·h per year, corresponding to Scenario C1; Scenario C2 assumes a smaller natural gas plant to compensate for lost generation from IPEC.
[d] Analysis carried out for wind build-out through 2030 and solar build-out through 2028 according to schedule in Table 3, corresponding to Scenario D1; Scenario D2 assumes less wind and solar to compensate for lost generation from IPEC.
[e] Cumulative over horizon, not discounted.
[f] Applies at end of horizon only due to assumed continuing build-out.
[g] Considering timeline of build-out and discounting future benefits at 3% per year.

Previous economic analysis calculated total net economic output attributable to CHPE at $3.6 billion retaining a discount rate of 0% (PA Consulting Group 2017). We calculated net economic output as $1.3 billion using a discount rate of 3% to be consistent with our approach for valuing

GHG emissions (see Table 13). Considering instead a 0% discount rate would increase net present value of future economic benefits to roughly $1.7 billion. The methodology used by PA Consulting Group (2017) employs yearly estimates for construction and operation activity specific to CHPE and economic market data specific to the counties in which project activities are located. Conversely, we consider only statewide average economic data and aggregated construction and operation phases with activities corresponding to generic transmission projects. It is plausible that these differences could explain differences on the order of 50% and so the analysis carried out by PA Consulting Group (2017) is broadly consistent with our findings. We also note that PA Consulting Group (2017) reported further benefits associated with expected impacts on the price of electricity in New York, which we did not consider.

PA Consulting Group (2017) reports that CHPE will create 800 long-term jobs and 2,600 jobs "during the height of its construction." The calculation of 800 long-term jobs includes potential impacts of ratepayer savings on electricity, which we do not evaluate here. This combines with different model approaches and data availability described above to explain the lower figure calculated here (180 long-term jobs as tabulated in Table 13). PA Consulting Group (2017) does not explicitly mention the duration of construction-phase jobs. We calculated 5,870 full-time-equivalent job years, which is equivalent to the figure reported by PA Consulting Group (2017) if the latter considers a construction-phase job duration of 2.3 years. Averaged over the duration of construction (roughly four years), our figure corresponds to roughly 1,468 full-time jobs for the duration of the project.

Local economic impacts calculated by JEDI are sensitive to a small number of economic parameters such as fraction of materials and labor sourced locally. The results here retain JEDI's default parameters except where it was possible to calibrate the model to match costs used elsewhere in the analysis (Section 2.3). In the case of the JEDI transmission model used to evaluate CHPE, for example, the values reported assume 0% for the local share of materials, 5% for the local share of labor related converter station construction, and 60% local labor for transmission line and right-of-way maintenance. The analysis presented here should be viewed as a first-order comparison of the likely economic effects of different hypothetical technologies rather than a definitive statement on the likely impacts of any specific project.

3.7 Considerations Specific to CHPE

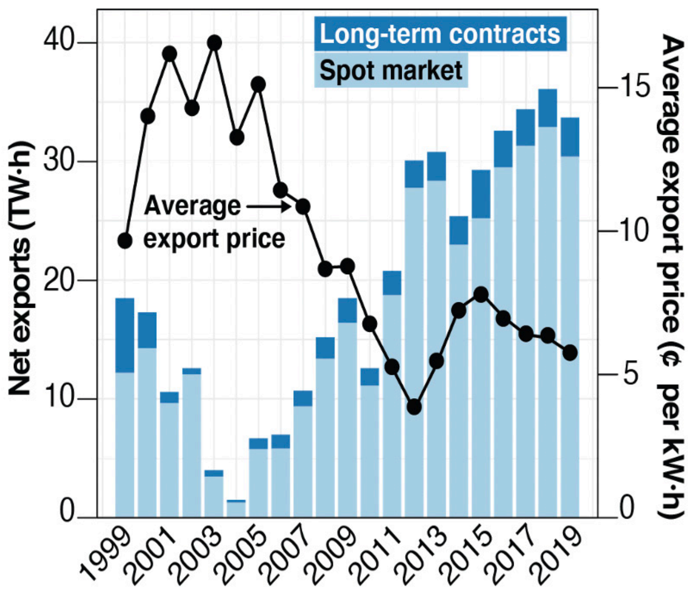
This analysis has suggested that CHPE is likely to present a cost-effective response to the closure of IPEC, largely because the value of avoided GHG emissions outweighs likely upfront expenditures. CHPE also increases the cost-effectiveness of other alternatives such as build-out of wind and solar and new natural gas by shortening the timeframe until which GHG emissions are displaced.

There has however been some disagreement over the extent to which CHPE may truly displace GHG emissions rather than simply reallocating existing exports (Energyzt Advisors 2020, Hydro-Québec 2020a). Here, we explore these issues, provide greater context for the assumptions retained in Section 2.1.2 and identify constraints on the benefits forecasted in earlier sections.

3.7.1 Impact of CHPE on Spot Market Exports and Displacement of Fossil Fuels

Environmental benefits associated with CHPE are contingent on the extent to which the project allows renewable generation in Quebec to displace fossil fuel generation in New York. There has been controversy over the extent to which CHPE may require a "reshuffling" of exports to other markets (including to Upstate New York), an outcome that may reduce benefits associated with CHPE (Energyzt Advisors 2020, Hydro-Québec 2020a). We have retained as a baseline assumption that CHPE would not cause reductions in exports to other markets. Here, we provide supplemental analysis to justify this assumption.

Figure 8. Net Exports (Bars) on the Short-Term Spot Market (Light Blue) and to Long-Term Contracts (Dark Blue) and the Average Export Price Paid (Joined Points) for the Period 1999–2019



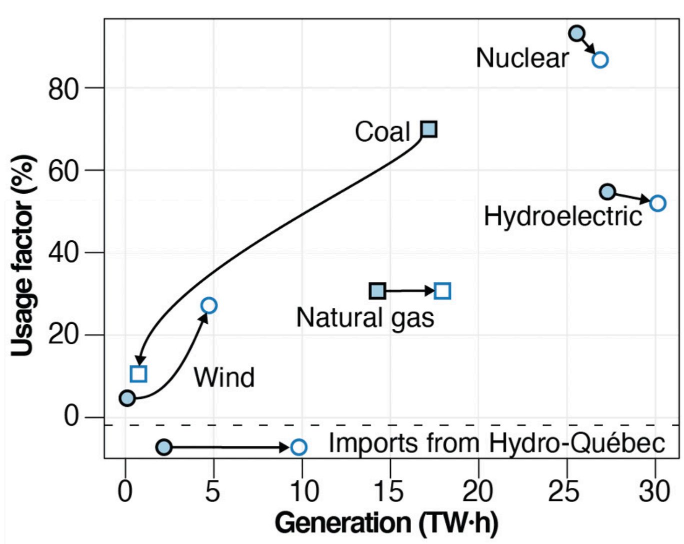
Note. Prices Are in 2019-USD.

Hydro-Québec's exports have played a role in the decarbonization efforts of neighboring jurisdictions including Upstate New York. For example, in the period 2006–2019, New York's gross imports from Hydro-Québec increased from roughly 2.1 TW·h to 9.9 TW·h (Canada Energy Regulator 2020). Figure 8 illustrates the growth in net exports in the period since 1999 to all jurisdictions including Upstate New York. This increase reflects falling prices, also illustrated in Figure 8, driven by historic surpluses of generation capacity in Quebec. As of January 1, 2020, Hydro-Québec reservoirs had reserves equivalent to 134.2 TW·h (Hydro-Québec Production 2020), approaching the theoretical limit and leading to non-revenue-generating spill events (Baril 2018, Couture 2018, Couture and Robillard 2019). Meanwhile, generating capacity has been expanding with, for example, the recent development of the 1,550-MW La Romaine hydroelectric complex (Hydro-Québec 2020c).

The falling prices of short-term hydropower from Quebec suggest that these imports are increasingly likely to be displacing low-marginal-cost local renewables in New York and elsewhere (bids to the New York power grid are made at prices that generally exceed marginal costs). For example, over the period 2006–2019, usage factors for local hydroelectric and nuclear generators declined by 3% and 7% respectively (NYISO 2007, 2019).

While imports from Quebec have played a role in decarbonization of Upstate New York, decarbonization reflects trends that far exceed the magnitude of these imports. Upstate decarbonization has been dominated by the virtual elimination of coal from the energy mix, falling from 17.1 TW·h in 2006 to 0.8 TW·h in 2019 (NYISO 2007, 2020a). Meanwhile, wind generation increased from 0.1 TW·h to 4.7 TW·h. These changes are shown in Figure 9 alongside the growth of imports from Quebec. Proposed Upstate wind and utility solar projects may deliver a further 11.5–13.6 TW·h per year as of 2024 (using the 2019 usage factor for wind and typical values for solar from Table 1) (NYISO 2020a). Applying the usage factors from 2006 to installed capacity in 2019 suggests a potential for at least 1.7 TW·h per year of additional local hydroelectric generation and 1.9 TW·h per year of additional local nuclear generation. Proposed distributed solar projects add a further 1.2 TW·h per year of generation Upstate, but target completion dates are unavailable for these projects (NYSERDA 2020). In the context of overall decarbonization, future demand for short-term imports from Hydro-Québec is uncertain and seems likely to decline regardless of decisions taken around the 8.3 TW·h of generation that would be allocated to CHPE.

Figure 9. Usage Factor vs. Generation for Fossil-Fuel (Square) and Low-Emissions (Circles) Sources in Upstate New York in 2006 (Filled) and 2019 (Hollow)



Note. Usage factor not calculated for imports from Hydro-Québec. Fuel oil and biomass generators are omitted for clarity (generation <2 TW·h in both periods).

Recent work has simulated direct costs under diverse scenarios for build-out of renewables in the northeastern United States and deepened integration of the electrical grid with Quebec (Dimanchev et al. 2020, Tries 2018, Williams et al. 2018). Findings generally point to an optimum in which U.S. renewables are built out substantially, exporting power to Canada during times of peak generation, while Canadian hydropower is used as a "battery," exporting to the U.S. at times of peak demand. Such a transition would likely reduce overall reduced exports of hydropower from Quebec to the northeastern U.S. relative to present levels (Tries 2018).

Overall, it is likely that CHPE would reduce the incentive of Hydro-Québec to bid at low prices on the short-term spot market in Upstate New York and will reduce the availability of generating resources for exports on the short-term spot market. However, available evidence suggests that a likely and optimal future allocation of these resources involves substantially reduced exports from Quebec to New York and elsewhere at times of low prices. Therefore, we do not view a hypothetical energy allocation via CHPE as likely to have a long-term stimulating effect on Upstate fossil fuel generation in a way that would negate the benefits characterized above.

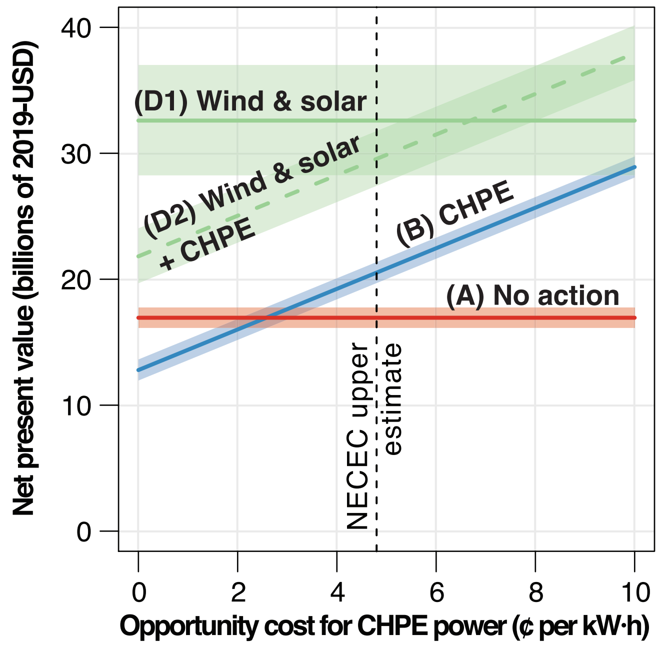
We also note that State regulators have some control over the adaptive behaviors of Hydro-Québec and can tie long-term import agreements to conditions on short-term imports, for example, if this is necessary to bridge the transition to greater buildout of Upstate renewables. The recently agreed power delivery contract for the New England Clean Energy Connect (NECEC) includes accounting mechanisms to ensure that power delivered by Hydro-Québec is "incremental." Minimum required exports from Hydro-Québec under the terms of NECEC increase proportionally to reductions in overall net and maximum export capacity calculated using the years 2014–2016 as a baseline (29.1 TW·h per year in net exports and 3,304 MW in transfer capacity) (Massachusetts Electric Company et al. 2018). This may ensure that reductions in capacity for short-term exports are compensated for by increased deliveries through NECEC.

3.7.2 Opportunity Cost of Exports via CHPE

In Section 3.7.1 we demonstrated that shifts in the Upstate New York electrical market are likely to reduce demand for net exports from Hydro-Québec and these shifts will very likely exceed the magnitude of the allocation of power via CHPE (8.3 TW·h per year). However, it is likely that Hydro-Québec has next-best opportunities for use of its hydroelectric generation (for example, exports to Ontario or New Brunswick), and there may be foregone environmental benefits for not allocating generation to these opportunities instead. This is the "opportunity cost" of a decision.

To the extent that environmental benefits are reflected in prices negotiated, the opportunity cost is related to the price that Hydro-Québec may charge for its energy exports (it will charge more to party A if there is a party B willing to pay a high price). For example, the levelized price of electricity agreed in the NECEC contract is 5.9¢ per kW·h including 4.8¢ per kW·h for "energy and environmental attributes" (in 2017-USD) (MA DOER 2018). This reflects some underlying opportunity cost plus, likely, an unknown (to us) profit margin imposed by Hydro-Québec that does not correspond to true physical costs. Therefore, in the case of NECEC, the underlying opportunity cost was likely less than 4.8 ¢ per kW·h.

Figure 10. NPV of Select Scenarios as a Function of Opportunity Cost for Power Delivered via CHPE



Note. New natural gas scenarios (C1 and C2) are omitted for clarity. Opportunity cost for NECEC is likely less than 4.8¢ per kW·h.

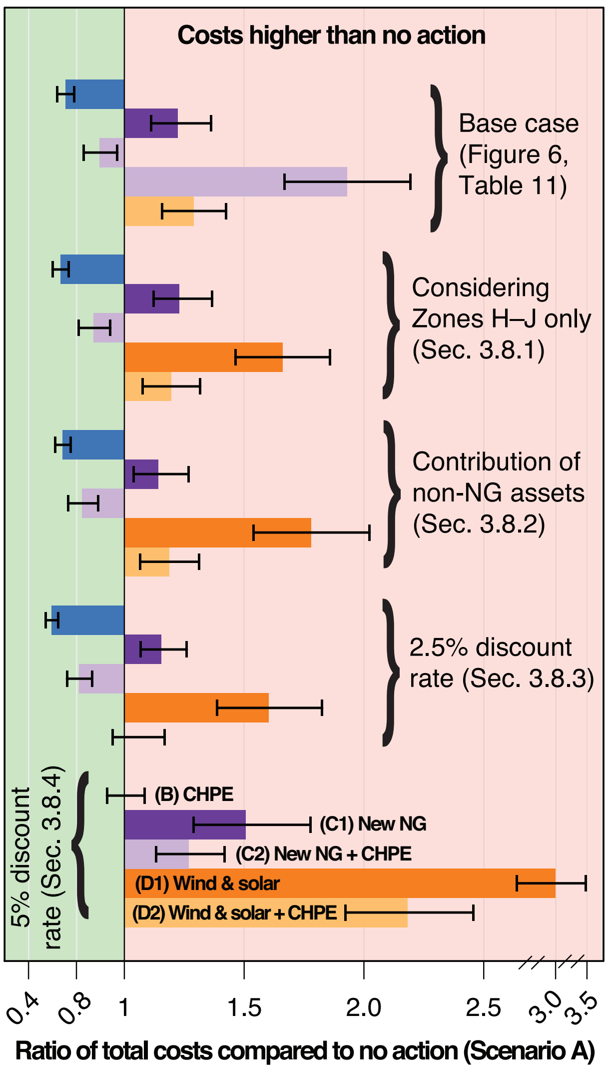
It is outside the scope of this study to quantify the opportunity cost of energy that may be exported to Downstate New York via CHPE as this would necessitate fully regional forecasts and subjective judgments about the likely evolution of energy demand, supply and other factors. However, parties' valuations of these opportunity costs will be revealed in eventual negotiations over the price New York entities ultimately pay for the power imported via CHPE from Quebec. Therefore, evaluating cost-effectiveness of CHPE under different hypothetical opportunity costs will provide useful guidance for New York entities as to the likely magnitude of benefits associated with CHPE for different energy price points, in comparison to alternatives.

Figure 10 adjusts the net present value of costs over the period 2021–2050 presented in Table 11 and Figure 6 for increasing assumptions of the opportunity cost associated with the 8.3 TW·h per year to be imported via CHPE (assuming a 3% discount rate as elsewhere in the analysis). We observe that for plausible values of the opportunity cost based on the upper limit from NECEC, addition of CHPE to build-out of renewable energy plans still presents benefits on the order of at least $4 billion over the period 2021–2050. In comparison to no-action Scenario A, increasing opportunity costs for power from CHPE reduces the comparative cost-effectiveness such that no-action may become nominally more cost-effective. However, this does not appear to be a likely long-term scenario given New York State's commitment to deep decarbonization.

3.8 Sensitivity to Modeling Parameters and Assumptions

Throughout the methods, we identified modeling assumptions and parameter choices that may impact the magnitude of impacts calculated or the relative cost-effectiveness of the scenarios evaluated. Here, we quantify these differences and discuss the significance for decision making. In Section 3.8.1 we quantify the impact on our results of considering only NYISO Zones H, I, and J in our analysis (excluding zones G and K) and also considering the entire state (Zones A–K). In Section 3.8.2 we consider the possibility that non-natural-gas generators (notably fuel oil) respond to the closure of IPEC. Section 3.8.3 quantifies the impact of assuming discount rates of 2.5% and 5% as compared to the 3% used in our main analysis.

Figure 11. Summary of Sensitivity Analyses



Note. Bars correspond to the ratio of total costs for each intervention scenario (B–D2) to the costs of no action (Scenario A). Ratios < 0 (green area) correspond to scenarios that are more cost-effective than no action. Error bars are 90% confidence intervals. Scenarios labels at bottom apply throughout.

In general, sensitivity of the absolute values of costs calculated for each scenario is greater than the impact on the difference between scenarios. That is, even though the value of net costs for each scenario is relatively sensitive to the assumptions we retain, the implications for decision-making do not change substantially. Figure 11 summarizes the sensitivity analyses carried out, showing how total costs of each intervention scenario (B, C1, C2, D1, and D2) compare to no-action Scenario A. A cost ratio greater than one means that the scenario is less cost-effective than no action and a ratio less than one means that the scenario is more cost-effective.

The major impacts on relative cost-effectiveness are: (1) if the closure of IPEC results in a large contribution of fuel oil generators, every technological intervention can become cost-effective and CHPE + new natural gas (Scenario C2) can become the scenario with the lowest net costs as compared to CHPE only (Scenario B) in our base case; (2) very highly discounting future GHG emissions can make no-action (Scenario A) the most cost-effective alternative, although CHPE-only (Scenario B) remains the most cost-effective alternative to no-action; and (3) assuming increased diversions of energy from Upstate to Downstate via CHPE steadily decreases the cost-effectiveness of all Scenarios of which CHPE forms a part (B, C2, D2), though CHPE-only (Scenario B) remains more cost-effective than no-action even when roughly half of the power it carried is assumed to be diverted from Upstate. We explore these analyses below.

3.8.1 Definition of "Downstate"

Air emissions are valued according to the counties in which the emissions occur (Section 2.4.2). In the main analysis, we consider that generating assets located in Zones G–K are available to compensate for the closure of IPEC, and air emissions are valued according to counties in those zones. In Table 14, we summarize the valuations of air impacts for alternative assumptions about NYISO zones where generation increases as a result of the closure of IPEC. We consider narrower regions around New York City: Zone J only and Zones, H, I, and J together. We also consider the effect of not isolating a "Downstate" region and modeling all NYISO Zones A–K together.

All alternative assumptions produce similar valuations to those presented in the main analysis. Confining the analysis to zones closer in proximity to New York City increases the valuations somewhat because more densely populated counties have higher total economic impacts of air pollution (see Table 8).

Table 14. Valuation of Air Emissions for Alternative Assumptions for NYISO Zones Compensating for Closure of IPEC (Millions of 2019-USD)[a]

NYISO Zones	Scenario					
	No action (A)	CHPE (B)	New NG (C1)	New NG + CHPE (C2)	Offshore wind and solar (D1)	Offshore wind and solar + CHPE (D2)
G–K[b]	130.1 (54.1–206)	63.0 (22.9–103.6)	87.0 (-74.2–157.4)	63.6 (30.4–96.6)	44.1 (17.8–75.5)	28.8 (11.6–46.7)
H–J	137.4 (60.6–214.6)	67.0 (26–108.4)	64.7 (-53.8–153.3)	66.3 (30.8–102.8)	77.7 (34.3–123.6)	36.4 (14.5–59.5)
J	136.1 (60.2–215.6)	66.6 (25.3–108.5)	100.5 (-3.4–226.4)	79.3 (45.6–116.4)	77.3 (33.9–123.9)	25.1 (11.1–39.8)
A–K	101.6 (55.8–148.6)	54.1 (22.2–86.7)	86.7 (41.2–130.9)	54.1 (27.9–80.8)	27.4 (13.4–46)	18.9 (10.3–27.7)

[a] Mean estimate (90% confidence interval); negative values for air quality impacts are in bold and correspond to possible countervailing benefits of reduced O_3 and/or PM due to NO_X titration (Lei and Wang 2014).
[b] Main analysis (see Table 11).

Precise simulation of air quality impacts requires a spatially and temporally explicit model for emission sources and receptors. Conversely, the present analysis aims only to characterize the possible range of air quality impacts in comparison to other endpoints and to formulate first-order approximations about the range of how such impacts compare across scenarios. It is therefore possible that increased emissions in the immediate vicinity of New York City compared to elsewhere in the broadly defined Downstate region would have relatively greater impacts. However, our simulation framework is not sufficiently spatially and temporally explicit to resolve these potential differences. The results of this sensitivity analysis indicate only that these differences are not likely to be sufficiently great to change our overall conclusions about comparative cost-effectiveness.

Table 15. Summary of Direct and Indirect Costs When All Generation Assets Compensate for the Closure of IPEC (Billions of 2019-USD)[a]

Impact type	Scenario					
	No action (A)	CHPE (B)	New NG (C1)	New NG + CHPE (C2)	Offshore wind & solar (D1)	Offshore wind & solar + CHPE (D2)
Upfront	0	3.7 (3–4.4)	4.3 (2.4–6.5)	5.6 (4.5–6.9)	17.5 (13.9–21.0)	12.3 (10.4–14.2)
Fixed	0	0.1 (0–0.1)	0.8 (0.4–1.2)	0.4 (0.2–0.6)	7.0 (5.8–8.2)	3.5 (3–4.1)
Variable	1.9 (1.4–2.5)	1.1 (0.8–1.4)	1.7 (1.2–2.3)	1.0 (0.7–1.4)	0.8 (0.5–1.2)	0.5 (0.3–0.7)
Battery storage	0	0	0	0	2.5 (2.3–2.7)	2.5 (2.3–2.7)
Fuel	8 (7.4–8.6)	4.6 (4.3–5)	7 (6.5–7.5)	4.2 (3.9–4.5)	3.1 (2.3–4.3)	1.9 (1.6–2.5)
GHG	8.8 (8.8–8.8)	4.4 (4.4–4.4)	7.6 (7.6–7.6)	4.2 (4.2–4.2)	2.6 (2–3.4)	1.6(1.4–2)
Air quality	0.1 (0.0–0.2)	0.1 (0.0–0.1)	0.1 (0.0–0.2)	0.1 (0.0–0.1)	0.0 (0.0–0.1)	0.0 (0.0–0.1)
Total	18.8 (17.9–19.7)	14 (13.1–14.8)	21.5 (19.3–24.0)	15.5 (14.2–16.9)	33.5 (29.0–38.0)	22.3 (20.1–24.6)

[a] Mean estimate (90% confidence interval).

3.8.2 Generating Assets Responding to the Closure of IPEC

In the main analysis, we assume that only natural gas generators will respond to the closure of IPEC. However, there is likely to be some increased contribution of oil-fired and other generators, notably during periods of peak demand. Here, we remove the constraint that only natural gas generators replace the power formerly supplied by IPEC. Whereas in the main analysis, existing natural gas supplies 100% of the power formerly delivered by IPEC (unless supplanted by CHPE, offshore wind and solar, etc.), here, it supplies 95%, and fuel-oil-powered facilities supply 5%. This is based on the relative contribution of Downstate natural gas and fuel oil at present day.

In Table 15, we present overall results that allow for contribution of generators other than those powered by natural gas. This sensitivity analysis substantially increases the total costs associated with no action (Scenario A), as fuel oil generators in particular have higher marginal costs and greater GHG and air impacts. It also increases the comparative cost-effectiveness of developing a new natural gas plant.

3.8.3 Discounting and Greenhouse Gas Valuation

In our main analysis, we assumed a discount rate of 3% per year as well as the corresponding central estimate for the value of GHG emissions developed by the Interagency Working Group (2016). Given the status of the ongoing deliberations on valuing GHG emissions in New York State, this is the single most relevant valuation for decision -making in this context. Here, we calculate how the principal conclusions of our analysis would change if other valuations were retained for discount rate. We recalculate all net costs considering discount rates of 2.5% per year and 5% per year. For each discount rate, we also apply the schedule of GHG emissions valuations presented by the Interagency Working Group (2016), converted to 2019-USD.

Higher discount rates assign lower values to future costs, notably recurring GHG emissions and therefore favor options with lower upfront costs such as no action (Scenario A). However, Scenario B (CHPE only) remains the most cost-effective scenario with total costs slightly lower than the next most cost-effective option (Scenario A). The mean difference in NPV between Scenario B and Scenario A under a 5% discount rate is $26.3 million (90% CI: $-752.0–$696.6 million) in favor of Scenario B. Under this higher discount rate, CHPE still increases the cost-effectiveness of new natural gas development, principally because of reduced recurring expenditures on fuel.

While CHPE continues to increase the cost-effectiveness of offshore wind and solar, it is not cost-competitive vs. no action (Scenario A) because the more heavily discounted value of avoided GHG emissions does not justify the large increased upfront expenditures. We note that considering a discount rate of 5% produces social costs of GHG emissions that are at the very low end of those commonly used in economic valuations, i.e., $14.88 per ton CO_2 (2019-USD) for 2020 emissions compared to a mean of $54.70 per ton reported in a meta-analysis by Wang et al. (2019) and $52.08 per ton used in our main analysis. Net costs associated calculated with a 5% discount rate are summarized in Table 16.

Table 16. Net Present Value of Direct and Indirect Costs Assuming Discount Rate of 5% (Billions of 2019-USD)[a]

Impact type	Scenario: No action (A)	CHPE (B)	New NG (C1)	New NG + CHPE (C2)	Offshore wind & solar (D1)	Offshore wind & solar + CHPE (D2)
Upfront	0	3.7 (3.0–4.4)	4.3 (2.4–6.5)	5.6 (4.5–6.9)	16.0 (12.7–19.4)	12.3 (10.5–14.2)
Fixed	0	0.0 (0–0.1)	0.5 (0.3–0.9)	0.3 (0.2–0.4)	5.3 (4.4–6.2)	2.9 (2.5–3.4)
Variable	1.3 (0.8–1.8)	0.8 (0.5–1.1)	1.3 (0.8–1.8)	0.8 (0.5–1.1)	0.3 (0.2–0.6)	0.2 (0.1–0.3)
Battery storage	0	0	0	0	1.2 (1.1–1.3)	1.2 (1.1–1.3)
Fuel	5.0 (4.7–5.4)	3 (2.8–3.3)	5.0 (4.7–5.4)	3.2 (2.9–3.4)	1.2 (0.8–1.9)	0.9 (0.7–1.2)
GHG	2.8 (2.8–2.8)	1.4 (1.4–1.5)	2.1 (2.1–2.1)	1.3 (1.3–1.3)	0.5 (0.3–0.7)	0.3 (0.3–0.4)
Air quality	0.2 (0.2–0.3)	0.1 (0.1–0.2)	0.1 (0.0–0.2)	0.1 (0.1–0.2)	0.1 (0–0.1)	0 (0–0.1)
Total	9.3 (8.7–10.0)	9.2 (8.4–10.0)	13.4 (11.4–15.8)	11.3 (10.1–12.6)	24.6 (20.9–28.2)	17.9 (15.9–19.9)

[a] Mean estimate (90% confidence interval).

Conversely, lower discount rates assign higher values to recurring future costs such as GHG emissions. In the 2.5% discount scenario, all conclusions presented in our main analysis continue to apply, and the absolute margins (i.e., the differences in dollars) between scenarios are greater. For example, Scenario B (CHPE only) continues to be the most cost-effective alternative and is associated with total costs \$6.6 billion (90% CI: \$5.8–\$7.4 billion) lower than no action (Scenario A). In our main analysis, this difference is \$4.28 billion (90% CI: \$3.4–\$4.9 billion). Net costs associated calculated with a 5% discount rate are summarized in Table 17.

4. CONCLUSIONS AND DISCUSSION

The closure of Indian Point Energy Center (IPEC) will remove approximately 15 TW·h per year of generation associated with low marginal costs and low emissions from the electrical generation portfolio of Downstate New York. This portfolio otherwise consists primarily of fossil fuel generating assets and so the closure of IPEC is likely to result in increased fossil fuel generation, at least in the short term.

There are several potential alternatives available for the Downstate electrical grid. These alternatives are not mutually exclusive and differ in terms of economic, environmental, and social impacts and technical and political feasibility. This analysis has identified a number of the most plausible alternatives as well as the endpoints that are likely to influence decision making.

Here, we summarize our primary findings and discuss the strengths and limitations of this study. We discuss future directions for research in the broader context of decarbonization in the Northeast United States.

Table 17. Net Present Value of Direct and Indirect Costs Assuming Discount Rate of 2.5% (Billions of 2019-USD)[a]

Impact type	Scenario					
	No action (A)	CHPE (B)	New NG (C1)	New NG + CHPE (C2)	Offshore wind & solar (D1)	Offshore wind & solar + CHPE (D2)
Upfront	0	3.7 (3.0–4.4)	4.2 (2.4–6.5)	5.6 (4.5–6.9)	17.8 (14.1–21.4)	12.3 (10.4–14.2)
Fixed	0	0.1 (0.1–0.1)	0.8 (0.4–1.3)	0.4 (0.3–0.7)	7.6 (6.3–8.9)	3.8 (3.2–4.4)
Variable	1.8 (1.1–2.4)	1.0 (0.6–1.4)	1.8 (1.1–2.4)	1.0 (0.7–1.4)	0.7 (0.4–1.1)	0.4 (0.2–0.6)
Battery storage	0	0	0	0	2.6 (2.4–2.8)	2.6 (2.4–2.8)
Fuel	6.7 (6.3–7.2)	3.9 (3.6–4.2)	6.7 (6.3–7.2)	4.0 (3.7–4.3)	2.5 (1.9–3.5)	1.5 (1.2–2)
GHG	13.3 (13.3–13.3)	6.6 (6.6–6.6)	11.6 (11.6–11.6)	6.6 (6.6–6.6)	3.8 (2.9–5.2)	2.4 (2–3.1)
Air quality	0.1 (0.1–0.2)	0.1 (0–0.1)	0.1 (0.0–0.2)	0.1 (0.0–0.1)	0.0 (0.0–0.1)	0.0 (0.0–0.0)
Total	21.9 (21.0–22.8)	15.3 (14.4–16.1)	25.3 (23.1–27.9)	17.7 (16.4–19.1)	35.1 (30.3–39.9)	23.1 (20.8–25.5)

[a] Mean estimate (90% confidence interval).

4.1 Overall Findings

- The closure of IPEC is very likely to result in increased direct costs from operation of fossil fuel generators and indirect environmental and health impacts. Our main analysis assumes that Downstate natural gas generators are able to compensate entirely for the closure of IPEC. In this case, we calculate the net present value of direct costs at $8.0 billion (90% CI: $7.2–$8.8 billion) and the indirect environmental impacts at $9.0 billion (90% CI: $8.9–$9.1 billion) over the period 2021–2050 assuming a 3% discount rate.

- Every alternative considered (new natural gas generation, development of CHPE, future build-out of offshore wind and solar assets) reduces environmental and health impacts relative to no action. The net present value of these savings ranges from $1.2 billion (90% CI: $1.2–$1.3 billion) in the case of new natural gas development (Scenario C1) to $7.4 billion (90% CI: $6.9–$7.6 billion) in the case of CHPE plus expansion of Downstate offshore wind and solar (Scenario D2) over the period 2021–2050 assuming a 3% discount rate.

- All scenarios in which net present costs are estimated to be lower than no action (i.e., in which costs of upfront expenditures are outweighed by savings in variable costs and environmental impacts) included CHPE (Scenarios B and C2).

- On the basis of minimizing net present costs, the most cost-effective scenario evaluated is CHPE alone.

- Anticipated build-out of Downstate offshore wind and solar projects are likely to have substantially greater local economic benefits than any other individual alternative intervention proposed. These economic benefits could be additive to those of other actions considered (for example, combining Downstate offshore wind and solar with new natural gas or CHPE).

- Planned build-out of Downstate offshore wind and solar in conjunction with CHPE presents the greatest total benefits (avoided air pollutant and GHG emissions and variable and fuel costs) and the greatest local economic benefits of any scenario considered. It also presents the greatest upfront expenditures, and these expenditures reduce overall cost-effectiveness relative to CHPE alone (Scenario B). This scenario has greater total costs than the status quo at a discount rate of 3% per year (total net costs greater by $4.9 billion, 90% CI: $2.6–$7.2 billion) but more cost-effective than the status quo at a discount rate of 2.5% per year (total net costs less by $1.2 billion, 90% CI: $1.2 billion more expensive to $3.8 billion cheaper) if stimulated economic activity is not considered. At a 3% discount rate, the comparative cost of offshore wind and solar vs. no action is outweighed by stimulated local economic activity of greater than $9 billion.

- We evaluated the impact on overall cost-effectiveness of CHPE of the possible opportunity costs for the power used to supply it. This was done in order to evaluate whether CHPE remains cost-effective considering the possible other uses for the underlying energy. We considered a range of plausible values based on the value associated with NECEC. We found that net benefits associated with coupling CHPE to build-out of Downstate wind and solar exist for wide ranges of plausible values for the opportunity cost of the hydropower used to supply CHPE. Therefore, benefits calculated here are robust to assumptions about the opportunity cost.

- Our analysis uses modeling assumptions that are favorable to the status quo (no action); when these assumptions are changed, the benefits of alternatives generally become larger. Extensive sensitivity analysis shows that CHPE improves overall cost-effectiveness of Downstate renewable energy transitions for all plausible assumptions and model parameter values.
- Employing a high discount rate (5%) increases the comparative cost-effectiveness of no-action Scenario A, but CHPE (Scenario B) remains the most cost-effective intervention.

4.2 Role and Limitations of Quantitative Valuations

This analysis has focused on outcomes that can be valued economically or otherwise quantified (e.g., jobs created, costs borne) because this facilitates comparison of alternative scenarios in common units of analysis. Impacts not quantified (i.e., those summarized in Table 10) are those upon which appropriate mitigation steps have been agreed between project proponents and regulators, for which total economic impacts are not likely to compare meaningfully against those already quantified, or for which quantitative valuation is not likely to be determinative in the decision process. There are however normative and practical limits to the usefulness of economic valuation of cultural, environmental and other resources (Gómez-Baggethun and Ruiz-Pérez 2011, McClelland et al. 2013). While we have used the sum of total impacts as a method to compare scenarios in terms of "overall" cost-effectiveness, we recognize that this does not fully capture how different scenarios may impact different constituencies in different ways. We therefore encourage readers to consider the scenarios we have developed in terms of individual endpoints, both quantitative and qualitative, in addition to the sum of costs.

Because our analysis has focused on "total" costs, we have not quantified any potential benefits that would accrue specifically to New York, for instance potentially lower electricity prices faced by ratepayers, under diverse scenarios. The distribution of costs and benefits for any alternative studied here is determined by contractual and political considerations, which are beyond the scope of this analysis. Contracts between the parties involved will be the primary mechanism by which the costs, benefits, and risks are distributed.

4.3 Causal Attribution and Impact Evaluation

We have limited our analysis of costs and benefits to those impacts which can be clearly causally linked to hypothetical actions in the narrow setting of likely near-term responses to the closure of IPEC. We have excluded impacts of hypothetical second-order impacts such as potential future generation in Canada or the effect of future Downstate renewables on the viability of economically inefficient fossil fuel generation.

CHPE would allow hydroelectric generation in Quebec to supply the New York City Area. This option has been subject to debate because of (1) the potential impacts on areas currently receiving relatively large amounts of energy on the short-term spot market (Energyzt Advisors

2020, Hydro-Québec 2020a) and (2) the environmental impacts of large reservoirs that supply the vast majority of the electrical supply in Quebec (Birchard et al. 2016, Birchard 2017, Eadie 2015, Riverkeeper Inc. 2019). Claim (1) centers on the possibility that CHPE would divert exports from short-term spot markets and increase fossil fuel generation in those markets, reducing net benefits. Conversely, claim (2) centers on the possibility that CHPE would make expanded generation infrastructure in Canada more likely, introducing supply-side impacts that require evaluation within the scope of any interconnection project.

Our analysis suggests that changes occurring over the next 5–10 years in the structure of the Upstate New York energy market will greatly reduce the demand for low-priced imports from Quebec, and that these changes are likely to exceed the allocation of power to CHPE. We therefore do not explicitly consider hypothetical second-order stimulation of fossil fuel generation in other markets as a result of CHPE. However, we do explore the effect on overall cost-effectiveness for certain hypothetical opportunity costs of this energy using recent data from NECEC as a rough indicator of the magnitude of these costs (Section 3.7.2). We find that net benefits are robust to assumptions about the opportunity cost.

The creation of hydroelectric reservoirs transforms terrestrial and aquatic environments and is associated with diverse environmental and health impacts (Rosenberg et al. 1997). Historically, U.S. regulators have taken the view that electrical interconnection projects with Canada are not causally related to underlying generating infrastructure and have therefore excluded generation-side impacts from the purview of U.S. environmental impact assessments (U.S. DOE 2017). It has indeed been noted that total exports are not constrained by interconnection capacity (Energyzt Advisors 2020) and so expanding this capacity will not necessarily lead to increased exports or increased generation capacity. To our knowledge, there are no currently planned hydroelectric projects in Québec beyond La Romaine, development of which has been in progress for many years independent of negotiations surrounding CHPE. For these reasons, in this analysis, we have not considered generation-side impacts.

From a wider perspective, there is indeed strong evidence that the U.S. export market has played a role in decision-making involving development of hydroelectric resources in Quebec and elsewhere (Calder 2019, Ferris 2017, Sullivan 2014, Young 1999). A comprehensive assessment of the costs and benefits of the further development of unexploited hydroelectric resources would need to evaluate risks and costs of reservoir construction as well as potential benefits from displacing fossil fuel generation. The framework we develop here may be expanded to guide broader decision making involving hydroelectric development, for which human health and environmental impacts have traditionally played a secondary role in site selection and project design (Calder et al. 2016).

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