Benefits and Costs of New York's Carbon Pricing Initiative

A Dynamic, Simulation-Based Analysis

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Updated 9/24/2018

- Revised slides: 15, 23, 31-33, 38
- Added slides: 40-42, 63

Overview

- Study Motivation & Research Questions
- Modeling Approach and Study Design
- Key Assumptions
- Simulation Results

Note: This analysis was conducted as part of RFF's Future of Power Initiative. It does not represent the NYISO Environmental Advisory Council. The authors wish to acknowledge funding from the Hewlett Foundation.

Motivation

- How does the NY Carbon Pricing Policy Proposal interact with the RGGI allowance market? Will pricing carbon at its social cost in the NYISO markets trigger the RGGI Emissions Containment Reserve?
- What are the impacts on electricity sector emissions of CO_2 in NY? In RGGI? In the Eastern Interconnection?
- How does the Policy affect emissions of other pollutants?
- How will the Policy affect location-based marginal prices in New York?
- How does the Policy affect NY REC and ZEC prices?
- How does the Policy affect social economic welfare and its components?

Basic Study Plan

- Employ a detailed power sector model, E4ST, to project effects of the NY Carbon Pricing Policy throughout the Eastern Interconnection
- Simulate 2020 and 2025 under the following futures:
  (1) Business-As-Usual (No Policy)
  (2) Carbon Pricing Policy, takes effect after 2020 and before 2025
  (3) Sensitivities and Alternative Policies
    i. Price-Responsive Load
    ii. RGGI price applied to small (< 25 MW), emitting NY generators
- Write academic paper. Results will be preliminary until end of peer review process, but that could be a year from now.

Key Elements of NYISO Carbon Pricing Straw Proposal and Draft Recommendations

- NY generators exempt from RGGI charged Gross Social Cost of Carbon (SCC)

- NY generators subject to RGGI charged SCC minus RGGI price (endogenous)

- “Apply carbon charges to external transactions such that they compete with internal resources as if the NYISO was not applying a carbon charge to internal suppliers.”

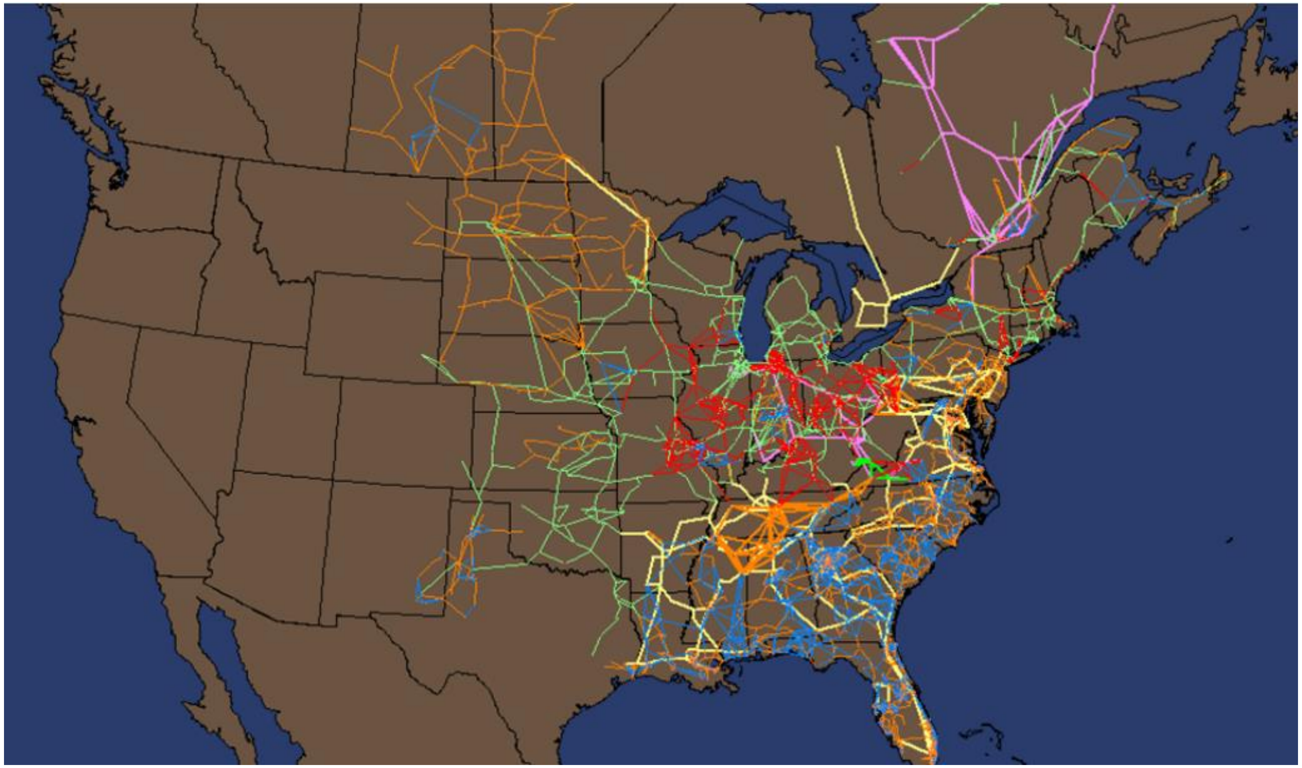
- NY carbon adder proceeds returned to NY electricity end-users

Methodology & Assumptions


ENGINEERING, ECONOMIC, AND ENVIRONMENTAL ELECTRICITY SIMULATION TOOL
E4ST

Model Physical Detail

The Eastern Interconnection model contains
14,225 branches, 5,222 nodes, and 8,190 generators



Current models of the three US & Canadian grids
Mexico model under development

Brief Model Description

- E4ST is designed to project the effects of policies, investments, and other scenarios

- E4ST is built on top of MATPOWER, an optimal power flow simulation software package

- E4ST added features include:

  (1) Simultaneous optimization of generator investment, retirement, and dispatch

  (2) Price-responsive demand at each node (normally)

  (3) Detailed representation of generation, transmission, and demand

  (4) Linked air pollution transport, fate and health effects model

  (5) Full benefit-cost analysis calculations

Overview of Some Important Input Data

- Location-specific fuel prices from AEO and NY CARIS.
- Hourly wind and PV generation data by site (wind) or nearest measurement station (PV) from NREL
- ~40 representative hours represent joint distribution of demand, generator availability, wind, and solar

Model Validation

2013 average electricity locational marginal prices in simulation output and in reality

Region	Average LMP from simulation	Actual average LMP	
New England	55.1	56.1	
PJM	37.4	38.0	
State			
west virginia	36.9	35.0	
virginia	40.5	38.6	
pennsylvania	41.9	39.3	
ontario	21.1	26.5	
ohio	34.7	35.1	
north carolina	43.2	38.6	
new jersey	45.4	40.8	
michigan	31.2	35.1	
maryland	42.7	39.6	
kentucky	33.9	35.0	
indiana	33.0	35.1	
illinois	32.0	32.2	
district of columbia	42.3	38.4	
delaware	43.9	40.3	
		Correlation:	**0.97**
NY zone (simple average of LMPs over all hours)			
WNY	37.6	37.8	
NYC	52.6	52.6	
LI	64.1	64.3	
Hudson	53.0	50.1	
Capital	57.5	50.4	
		Correlation:	**0.95**

Applications of the E4 Simulation Tool to Date

Project short-run and long-run effects, costs, and benefits of the following:

- **CO_2, SO_2, & NO_X** cap-and-trade, rate limits & fees
- **RENEWABLE ENERGY** standards and cost changes
- Different **FUEL PRICE** paths and **DEMAND GROWTH** paths
- Different **PRICE RESPONSIVENESS** of demand
- **NUCLEAR AND COAL RETIREMENTS**, including the DOE NOPR
- **OFFSHORE WIND FARMS** off east and west coasts
- Added **DC TRANSMISSION** lines
- **INTERACTIONS** of the above

See appendix for list of publications.

Key Assumptions

Generation Resources, Fuel Prices, Load

- **Existing Resources**
  - Starting generator dataset includes those online at the beginning of 2017
  - Endogenous exit, and exogenous near-term planned retirement
  - NY upstate nuclear units, except Indian Point, are in operation in 2025
  - All NY coal-fired units retire by 2020
- **New Resources**
  - Endogenous entry, and exogenous near-term planned additions, including 800 MW offshore wind
  - Costs/characteristics per Annual Energy Outlook (AEO) 2018
    - Capital costs scaled down over time per NREL's Annual Technology Baseline 2018
- **Fuel Prices**
  - Regional, annual fuel prices from AEO 2017, with natural gas prices adjusted downward using NYMEX Henry Hub futures price (~$3.10 nominal in 2025).
  - NY zonal natural gas prices derived from CARIS 1 low-case assumptions.
- **Load**
  - Regional annual load and demand growth per AEO 2018, except for NY
  - NY zonal annual load per CARIS 1, load shapes based on historical hourly load
  - Non-price-responsive load for simplicity and to isolate Policy implications (normally price responsive in E4ST)

Assumed Average Natural Gas Prices to Generators, by NY zone

Natural Gas Prices (2013$/MMBtu)

Zone	2025
A	$2.18
B	$2.18
C	$2.18
D	$2.18
E	$2.18
F	$2.63
G	$2.63
H	$2.63
I	$2.63
J	$2.30
K	$2.53

Source: Proportional to CARIS 1 2025 NG prices, but scaled down to be consistent with NYMEX NG price futures for 2025 (plus the CARIS 1 / AEO differential between average price to NY generators and Henry Hub price).

Key Assumptions

Policies/Regulations in BAU

- **Regional Greenhouse Gas Initiative (RGGI)**
    - Implemented as cap-and-trade program for power generators > 25 MW (RGGI allowance price is endogenous)
    - Cost Containment Reserve (CCR), and Emissions Containment Reserve (ECR), Minimum Reserve Price, per RGGI Model Rule
    - NJ and VA assumed to join by 2025
- **Renewable Portfolio Standards (RPS)**
    - NY Tier 1 RPS: New capacity to satisfy remaining obligations assumed to be entirely wind & solar PV within NY
    - Regional, aggregate RPSs applied in rest of EI
- **Installed Capacity Requirements (ICAP)**
    - Imposed in each NERC sub-region, including New York
- **Interface Flow Constraints**
    - Individual line limits supplemented with internal and external interface flow constraints applied per NYISO

Representing the Border Flow Price

Carbon Pricing Draft Recommendations (NYISO for IPPTF 2018): "apply carbon charges to external transactions such that they compete with internal resources as if the NYISO was not applying a carbon charge to internal suppliers."

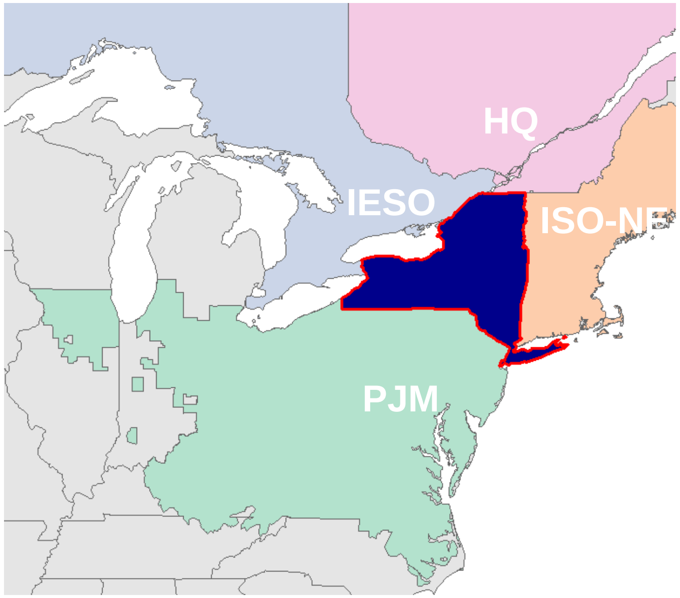
We apply this to each of four borders, one with each neighbor. We use constraints, which is equivalent to using prices, but more direct. The constraints create the prices — specifically, the prices that make the flows equal what they would be if the carbon adder were suddenly removed.

Net imports across each border in each hour equal what they would be *if the carbon adder were suddenly removed*. (Like in Draft Recs and prior documents.)

Iteration required, repeating these steps:

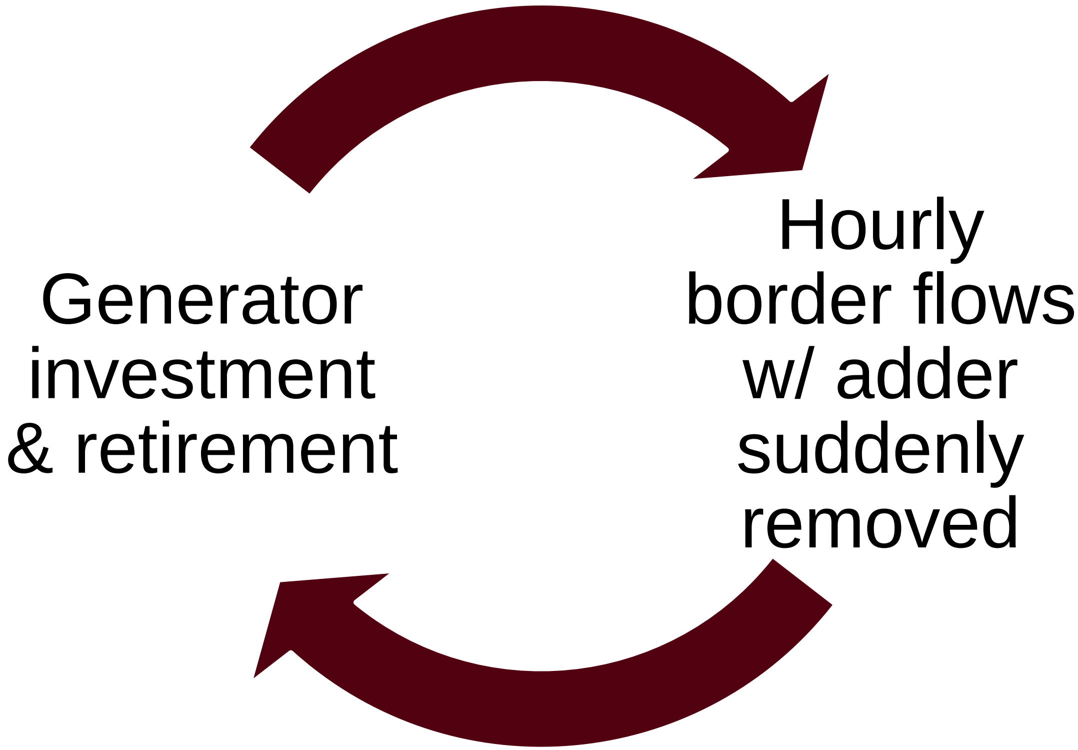
1) Simulate 2025 without border prices, and observe hourly net imports for each border.

2) Simulate 2025 again, constraining hourly net imports to equal those in (1).



Representing the Border Flow Price *with the Carbon Adder*

Iterate to equilibrium of hourly border flows (prices) and generator investment/retirement



Representing the Border Flow Price *with the Carbon Adder*

Iterate to equilibrium of hourly border flows (prices) and generator investment/retirement

Iteration	Adder from	Hourly net imports from	Starting EGUs from	Endogenous Investment & Retirement?
1	none	endogenous	2020	Y
2	1	**from 1**	2020	**Y**
3	none	endogenous	**from 2**	n
4	2	**from 3**	2020	**Y**
5	none	endogenous	**from 4**	n
6	4	**from 5**	2020	**Y**
7	none	endogenous	**from 6**	n
8	6	**from 7**	2020	**Y**
9	none	endogenous	**from 8**	n
10	8	**from 9**	2020	**Y**

Equilibrium indicated by results 10 = results 8 almost exactly.

Some differences from Brattle/NYISO MAPS analysis

- RPS payments received by RPS generator with contracts are unaffected by the Policy, i.e. they receive a windfall

- Generator investment and retirement are endogenous, that is, they are predicted, based on profitability, as part of the simulation

- Border flows in each hour are held to what they would be if the carbon adder were removed suddenly (which we believe is the Policy), rather than to what they would be if the carbon adder had never been implemented. Consequently, the generation fleet can differ.

- Average natural gas prices are based on NYMEX natural gas futures prices rather than AEO/CARIS natural gas prices.

Results

Preface

- *In this presentation, we describe the results of the simulations. For simplicity, we often omit the words "In the simulations."*

- *"BAU" refers to the business-as-usual, or reference, scenario, which is the scenario without any version of NY carbon adder.*

- *All dollar values are in 2013 dollars.*
  To convert to projected 2025 dollars, multiply by 1.24.

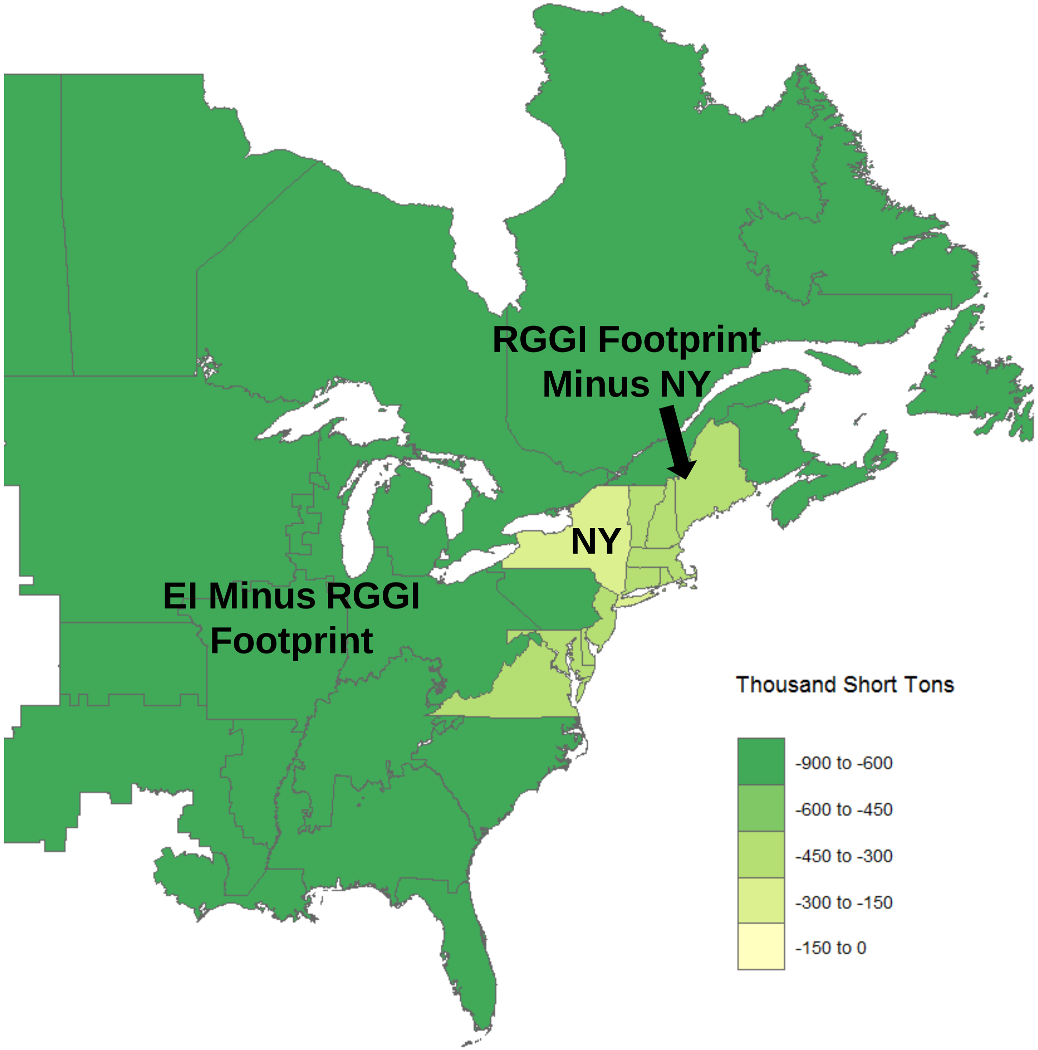
- *To start, recall that RGGI emissions are unchanged by the Policy unless the ECR, CCR, or allowance price floor is triggered.*

Effects of Policy on CO_2 Emissions

Change from BAU in 2025

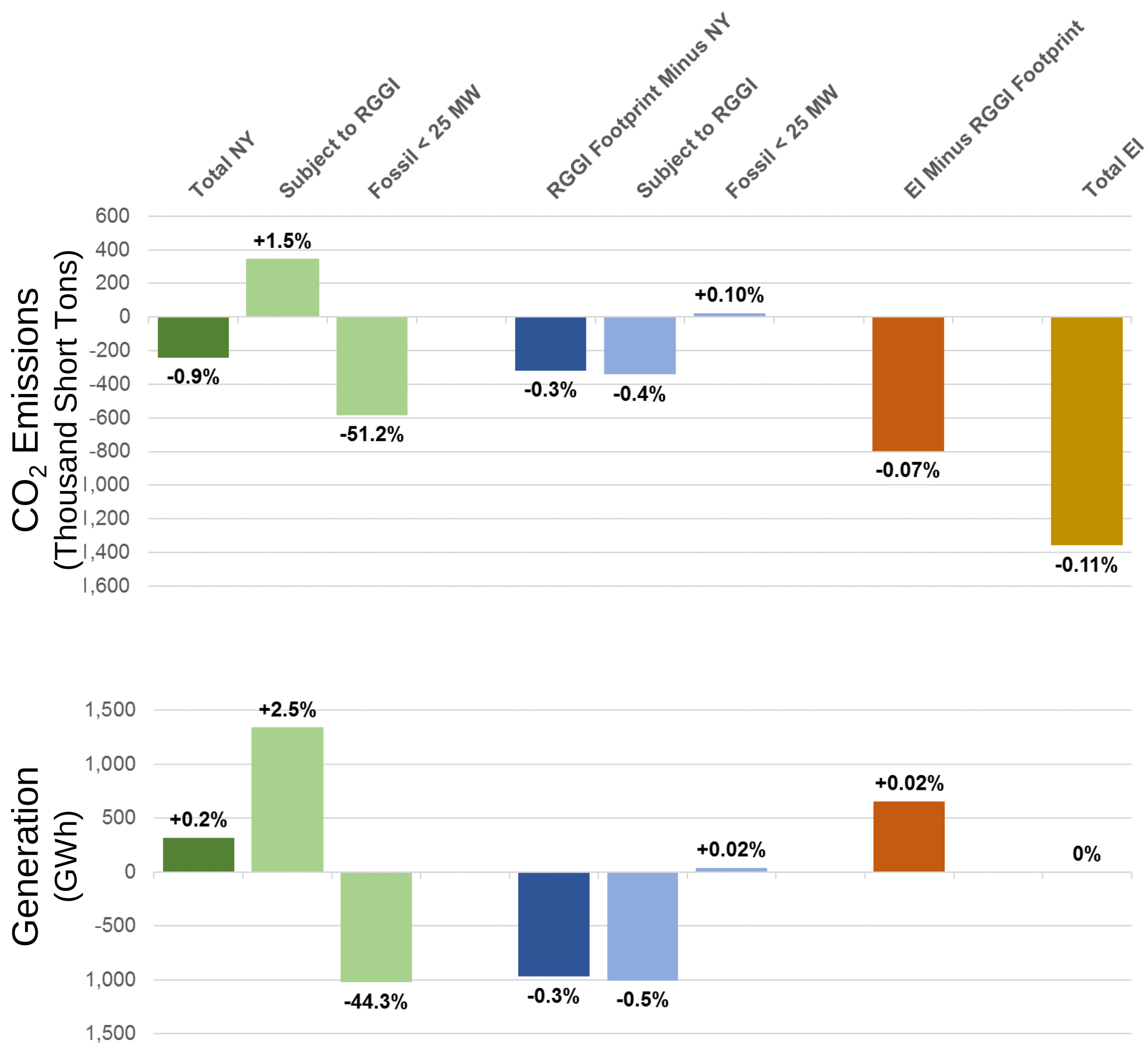
The Policy reduces emissions in NY, the rest of RGGI, and the non-RGGI parts of the Eastern Interconnection. There is *negative* leakage.

How???



Effects of Policy on CO_2 Emissions and Generation

Change from BAU in 2025



NY reductions are from units that are exempt from RGGI.

Generation by NY RGGI units increases in response to that and to border price…

…not enough to increase *total* NY CO_2,

…but requires emissions by non-NY RGGI units to decrease.

Policy reduces emissions outside RGGI footprint by changing elec. prices in a way that very slightly favors NG over coal.

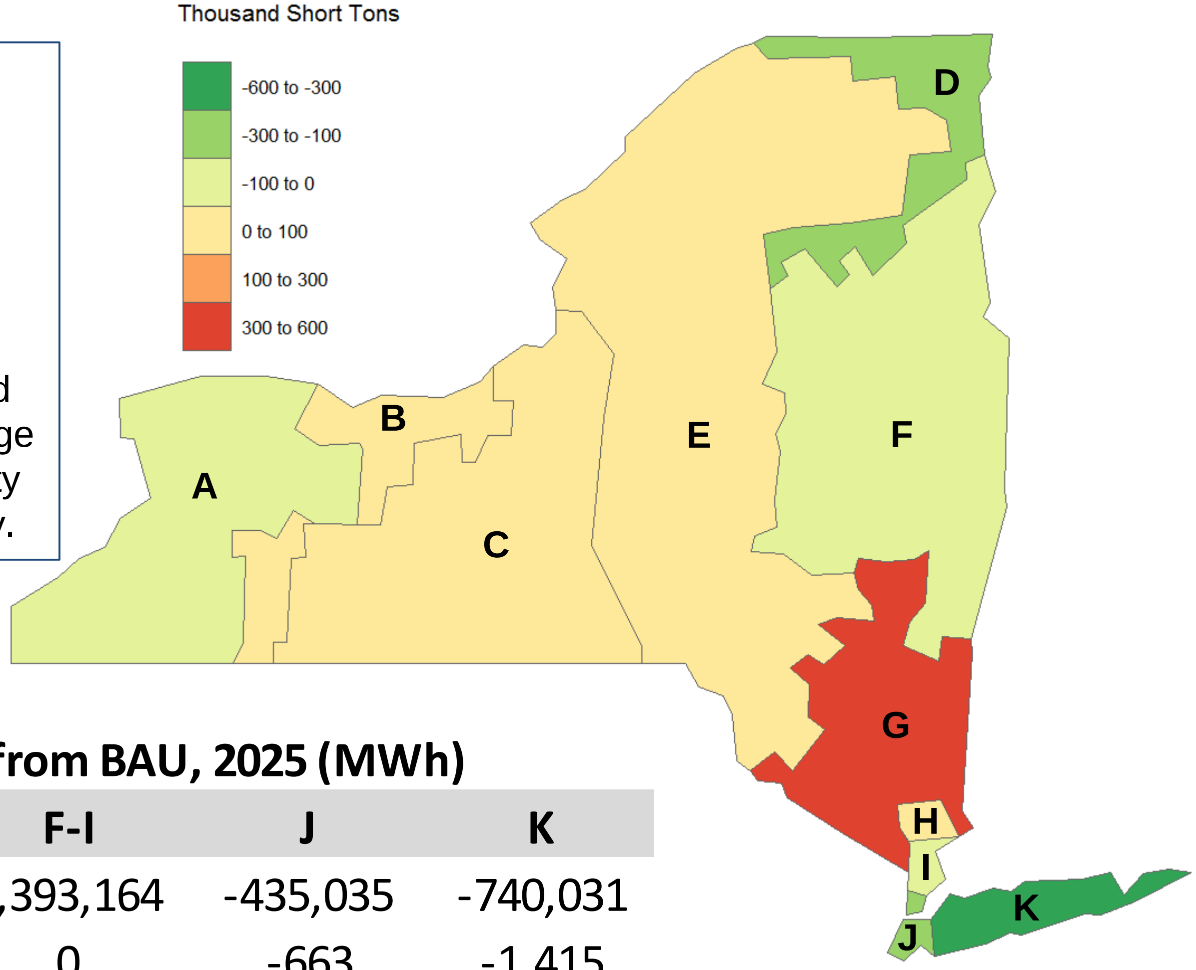
Effects of Policy on NY Zonal CO_2 Emissions

Change from BAU in 2025

The Policy reduces total NY power plant emissions.

Zone G has an increase due to an efficient NGCC unit there.

The Policy has only small effects on projected generator investments and retirements in NY. The largest change is a slight increase in NGCC capacity and slight decrease in NGT capacity.



Generation Change from BAU, 2025 (MWh)

	A-E	F-I	J	K
Natural Gas	-93,179	1,393,164	-435,035	-740,031
Oil	1	0	-663	-1,415

Effect of Policy on RGGI Price

RGGI Impacts, 2025

	BAU	Policy	Change
Assumed Cap (Thousand Short Tons)	111,285	111,285	0
Allowance Price (2013$/Short Ton)	$9.10	$9.59	$0.49

The Policy might be expected to reduce the RGGI price because it directly disincentivizes emissions by some of the RGGI generators, specifically the ones in NY, and hence disincentivizes their demand for RGGI allowances.

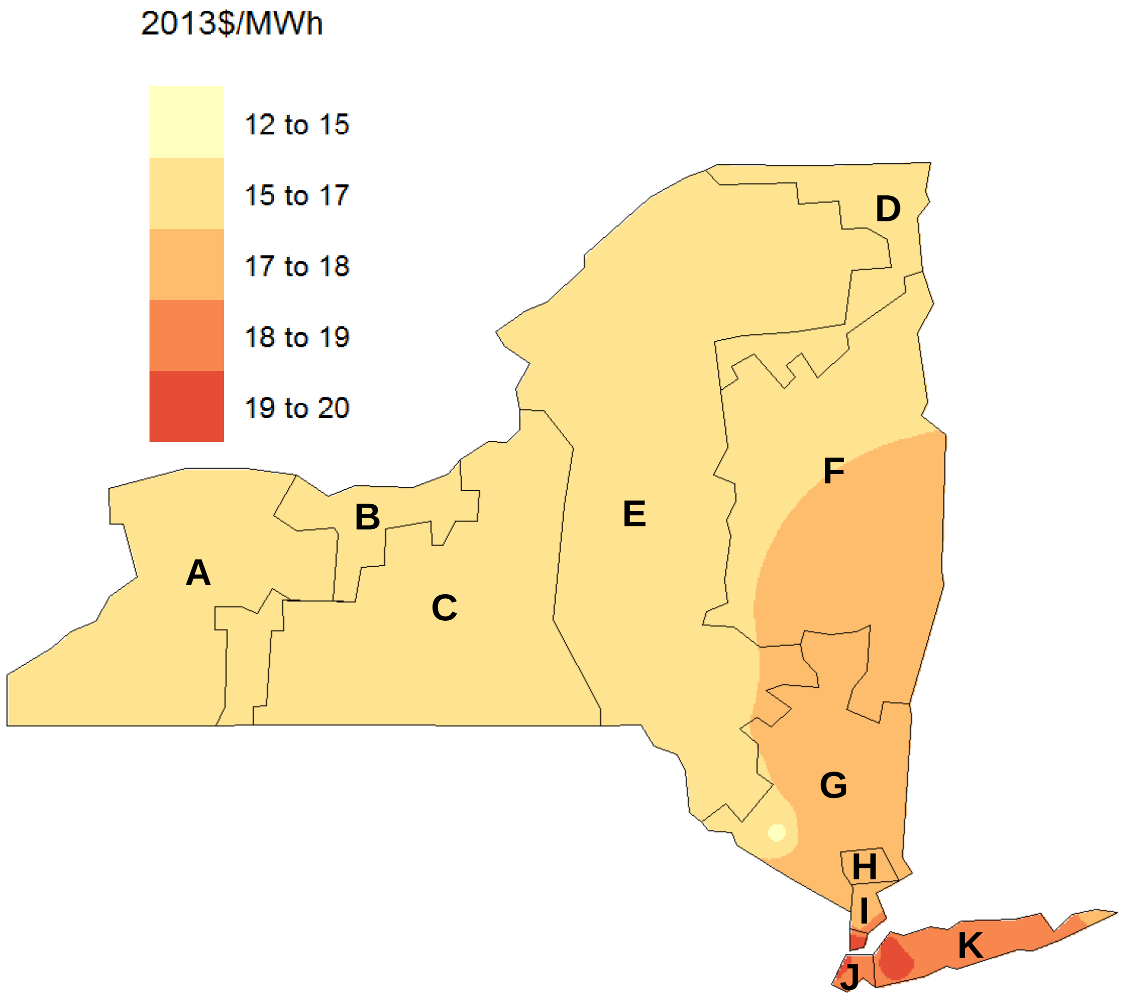
However, **it also reduces generation by emitting NY units that are exempt from RGGI**. **That increases the demand for generation by units subject to RGGI**.

This supports the assumption in Brattle modeling that Policy doesn't change RGGI price.

Also means RGGI Emission Containment Reserve is not triggered.

Effects of Policy on LBMPs in NY

Change from BAU in 2025

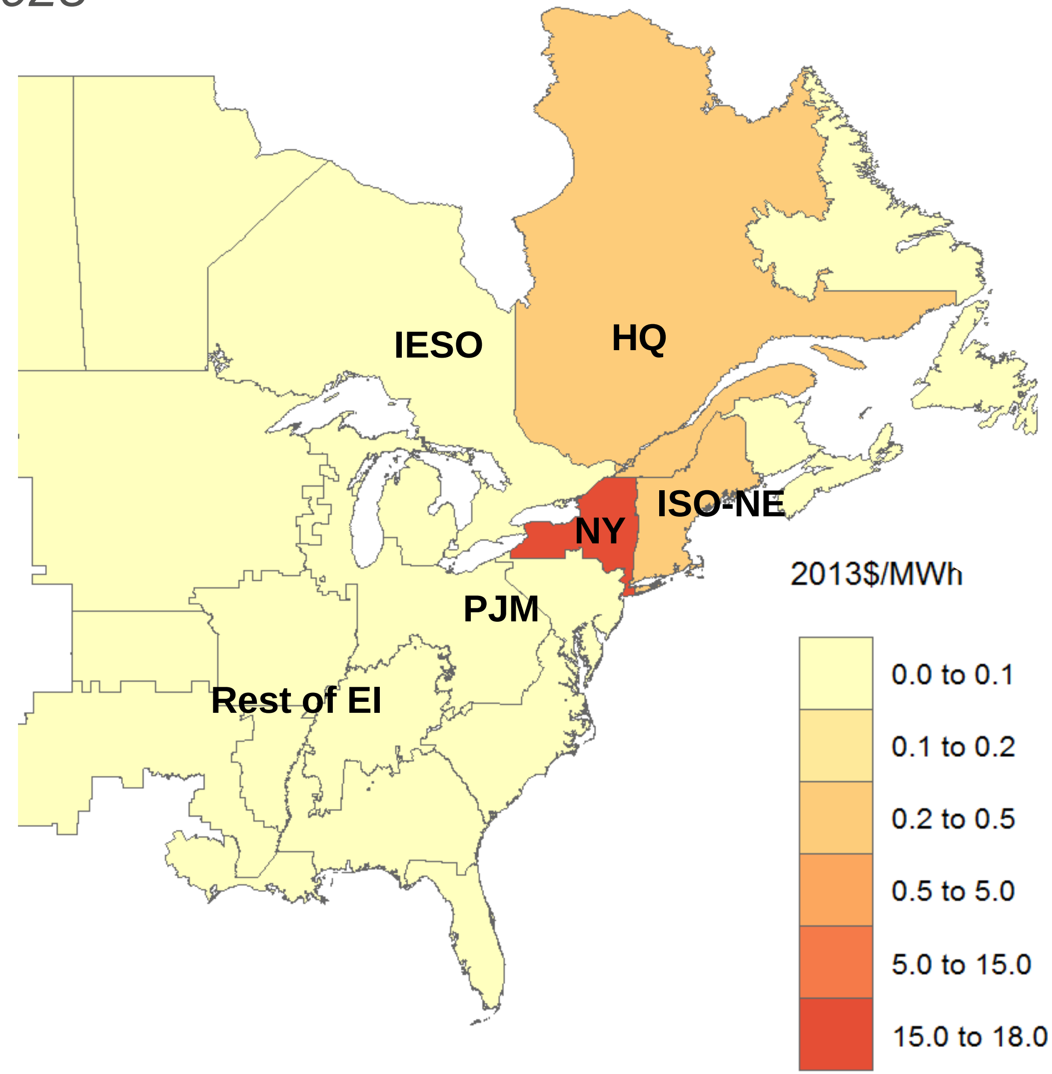


The Policy increases electricity prices most in **southeastern** New York.

Effects of Policy on LBMPs in the Eastern Interconnection

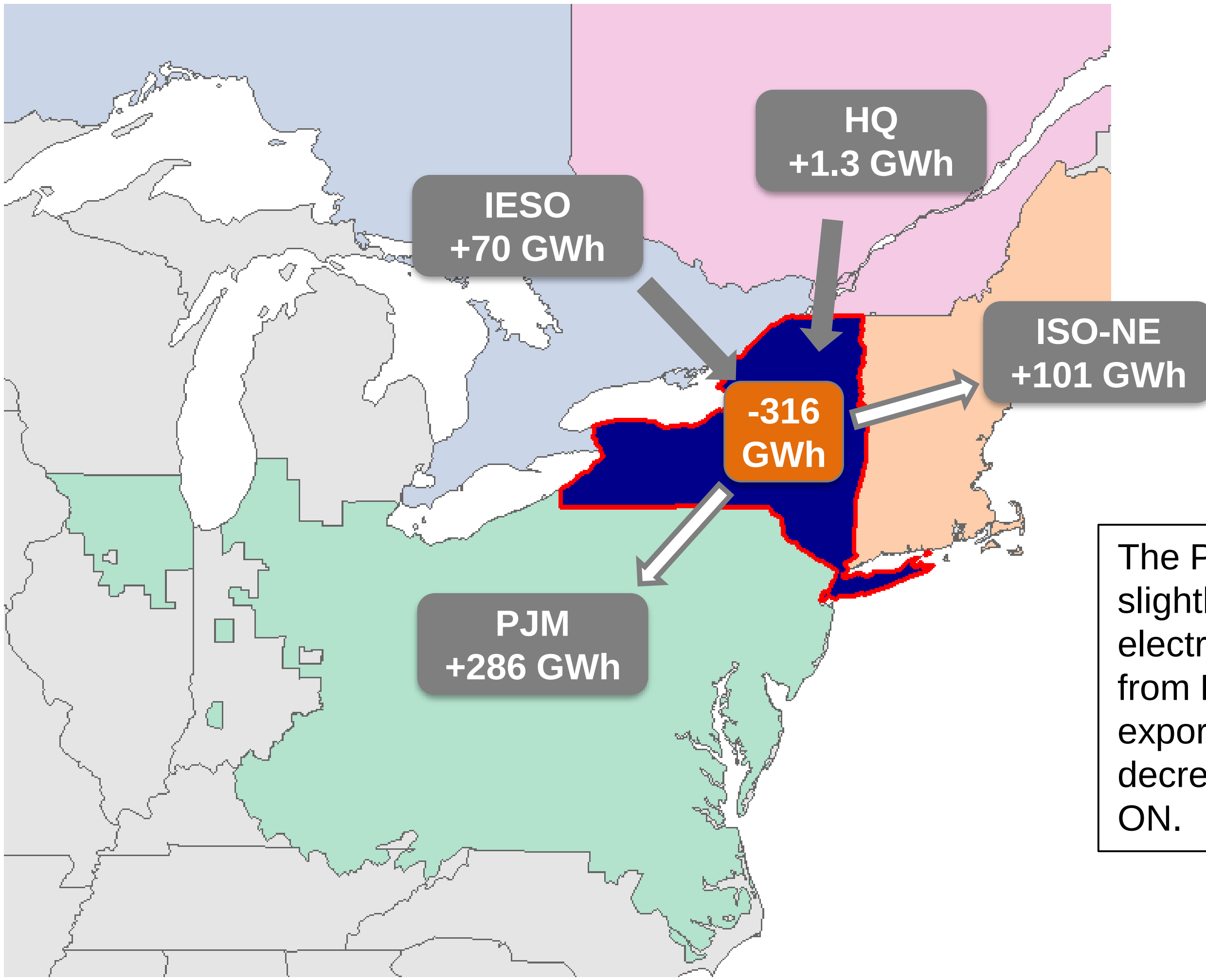
Change from BAU in 2025

Outside of NY, the Policy increases electricity prices, primarily in Quebec and NE.



Effect on Policy on Net Imports

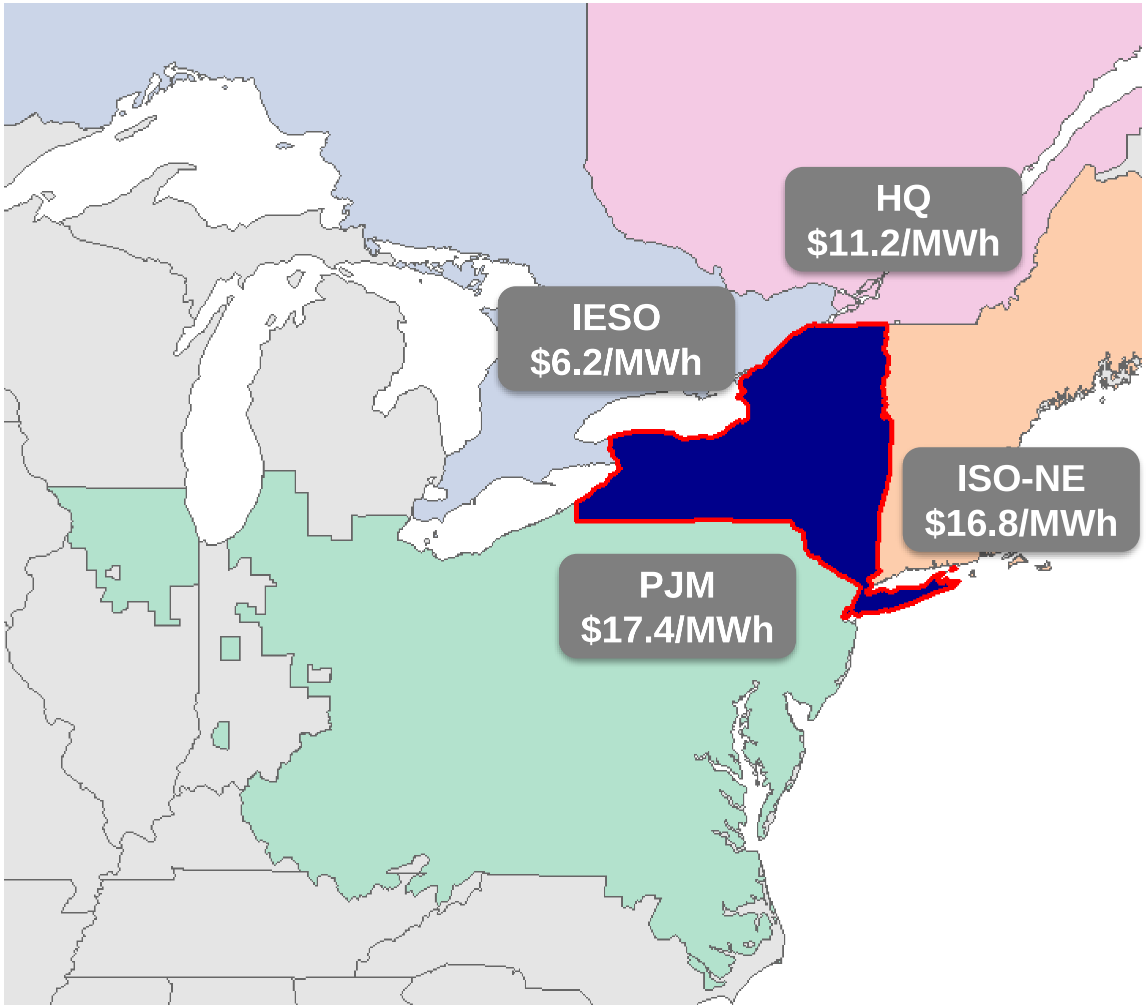
Change from BAU in 2025



The Policy very slightly reduces NY electricity imports from PJM, increases exports to NE, and decreases exports to ON.

Implied Policy Border Prices

Annual Average in 2025 (2013$)



Effects of Policy on Emissions and Their Damages

	NY		Rest of Eastern Interconnection	
Emission Type	Quantity	Damage (2013$ thousands)	Quantity	Damage (2013$ thousands)
CO_2 (Thousand Short Tons)	-242	-$11,110	-1,116	-$51,359
SO_2 (Thousand Lbs)	-11	$499	-7,097	-$149,726
NOX (Thousand Lbs)	-972	-$3,292	-4,170	-$16,609
Total		-$13,903		-$217,694

Because New York has no coal-fired capacity in 2025, less than 25% of the estimated environmental benefit is from NOX and SO_2 emission reductions. Estimated SO_2 damage actually increases slightly because the Policy shifts some emissions to locations that cause larger estimated health damage per pound emitted.

Rest of EI: Policy changes electricity prices in a way that very slightly favors NG over coal generation.

Breakdown of Policy Effect on NY End-Users

Change from BAU in 2025 (2013$ millions)

End-User Benefit Components		**NY**
Payments by End-Users		
Energy Payments	-	$2738
Capacity Payments	-	-$645
Tier 1 REC Payments	-	-$254
ZEC Payments	-	-$296
Rebates to End-Users		
Internal Congestion Revenue	+	$159
Border Congestion and Import Charge Revenue*	+	$48
Internal Carbon Adder Revenue**	+	$883
End-User Net Benefits		**-$453**

* Net revenue both from the Policy's border charge/credit and from cross-border transmission congestion. We assume that revenue is split fifty-fifty between NY and the bordering systems. The reader can easily modify this split assumption and the calculation.

** Revenue from the Policy's charge on NY power plant fossil CO_2 emissions.

These do not include environmental benefits to end-users, which are positive.

This is 0.29 cents/kWh, which is $2.90 per MWh, welfare cost to end-users.

Effects of Policy on Welfare

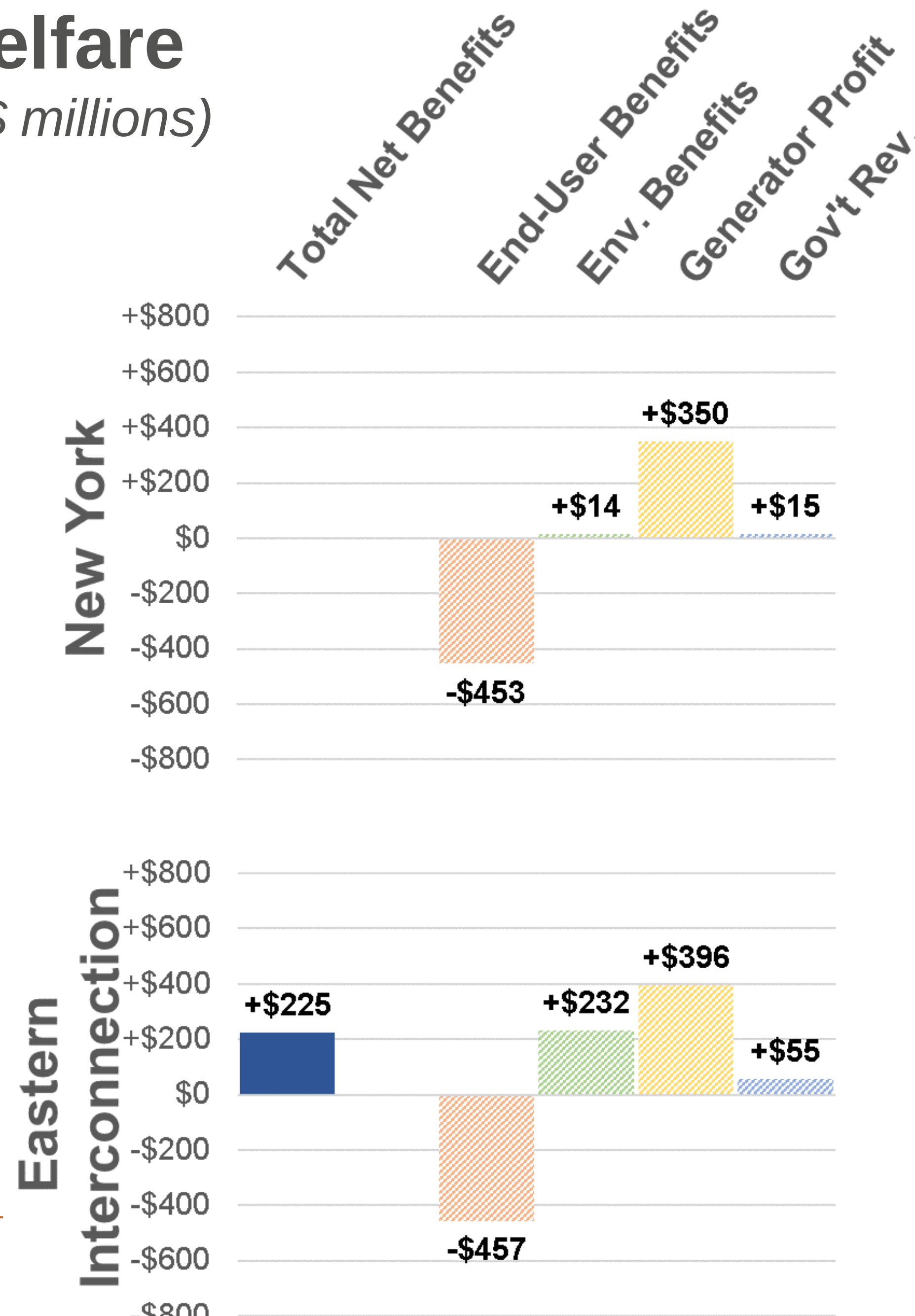
Change from BAU in 2025 (2013$ millions)

Welfare cost to end-users of 0.29 cents/kWh, which is $2.90 per MWh.

This does not include environmental benefits to end-users, which are positive.

There is an somewhat smaller increase in NY generator profit.

Total system-wide net benefits are positive $225 million, principally because of the very slight reduction in non-NY coal emissions caused by the Policy.



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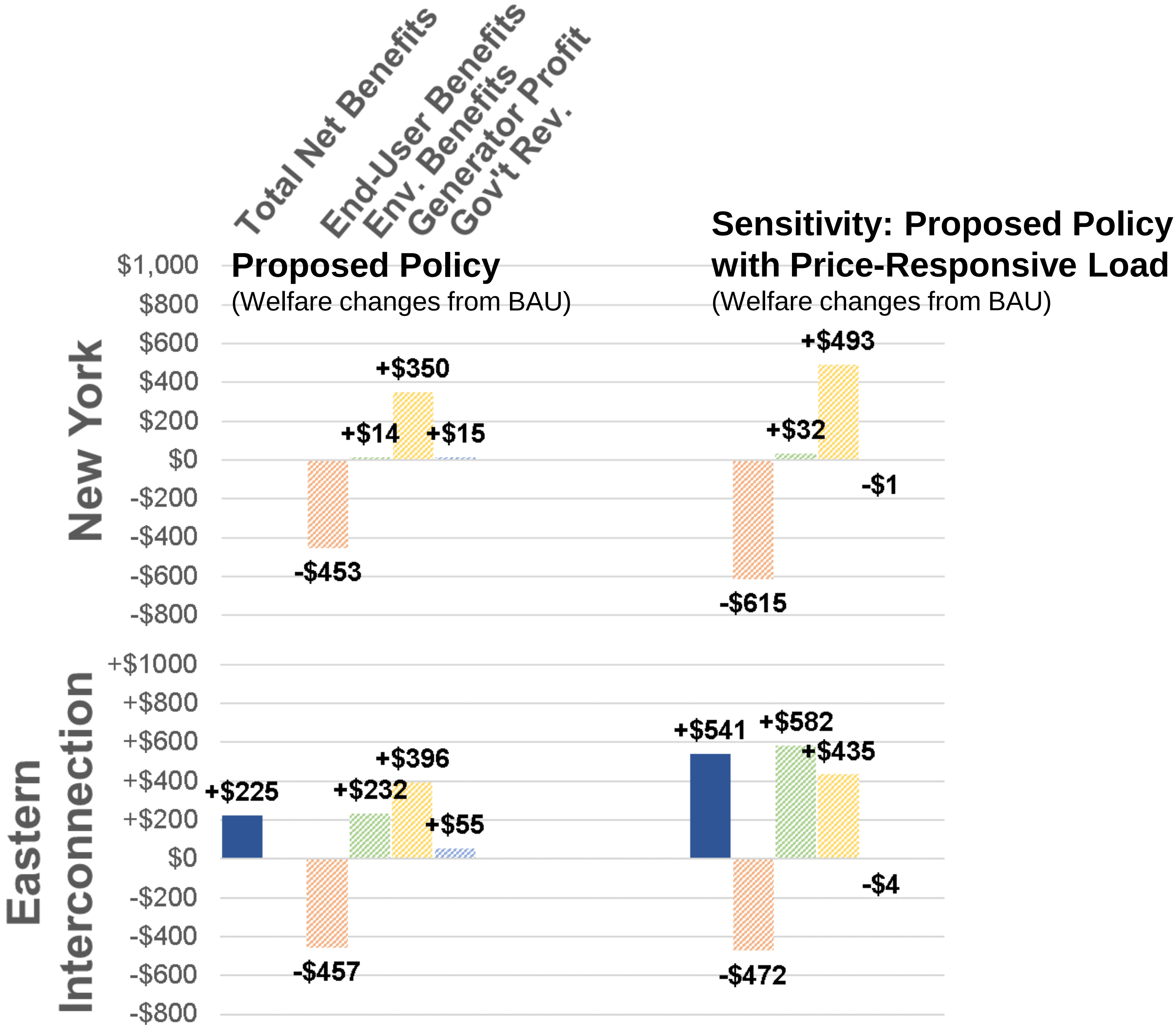


Total Net Benefits
End-User Benefits
Env. Benefits
Generator Profit
Gov't Rev.
Proposed Policy
(Welfare changes from BAU)
Sensitivity: Proposed Policy with Price-Responsive Load
(Welfare changes from BAU)
New York
$1,000
$800
$600
$400
$200
$0
-$200
-$400
-$600
-$800
+$350
+$14
+$15
-$453
+$493
+$32
-$1
-$615
Eastern Interconnection
+$1000
+$800
+$600
+$400
+$200
$0
-$200
-$400
-$600
-$800
+$225
+$232
+$396
+$55
-$457
+$541
+$582
+$435
-$4
-$472

Approximate Revenue/MWh of Upstate Nuclear Generators, Before ZEC, Using Approximation of PSC Method to be Used in Calculating ZEC Prices (in 2013$/MWh)

Revenue component	No Policy	Policy	Difference
Zone C energy price + $6	28.25	44.00	15.76
Capacity payments per MWh*	12.78	10.49	-2.30
Approximate revenue/MWh	41.03	54.49	13.46

Notes

$6 is benchmark price difference between nuclear unit buses & zone A. We actually use $5.55 because we convert it from 2018 to 2013 dollars.

**Assuming constant 89% capacity factor*

ZEC Prices with and without Policy (2013$)

Scenario	CO2 social cost	–	RGGI allowance price	–	Amount by which zone C energy price & NYCA capacity price exceed nominal	=	ZEC price per MWh
In $ per short ton							
No Policy	$46.51	–	$8.39		This difference is the "net CO2 externality"		
Policy	$46.51	–	$8.39				
In $ per MWh, assuming .533 tons per MWh							
No Policy	$24.77	–	$4.47	–	$9.60	=	$10.70
Policy	$24.77	–	$4.47	–	$23.06	<	$0.00
Difference							$10.70

Notes:

PSC method (CES order, Aug. 1, 2016, Appendix E, pages 12-13) uses RGGI price of $10.41 and $39 revenue benchmark without adjusting them for inflation, so we do as well. In contrast, the Brattle Report assumed the $39 benchmark would be adjusted for inflation.

Assumed avoided tons per MWh are reduced from 0.538 because renewable genration exceeds 50 TWh in 2024 in our simulation results, triggering a reduction.

**Prior to April 2023, this step uses amount by which zone-A LBMP + capacity revenue exceeds $39. Starting April 2023, if the average LBMP difference between the nuclear unit busses and Zone A is the same as in 2017-2022, which we assume, then the step effectively uses the amount by which the average LBMP at nuclear units exceeds $33 (PSC CES order, Aug. 1, 2016, Appendix E, pp. 8-9).*

Effects of Policy on NY REC Price (Tier 1)

Tier 1 REC Price Impacts, 2025

	BAU	Policy	Change
REC Price (2013$/MWh)	$37.44	$22.13	-$15.31

The Policy increases electricity prices in New York, so that wind and solar developers do not need as high of a REC price in order to be willing to build. The REC prices are higher in this analysis than in some others because we assume lower NG prices, closer to futures market prices, than some other analyses do.

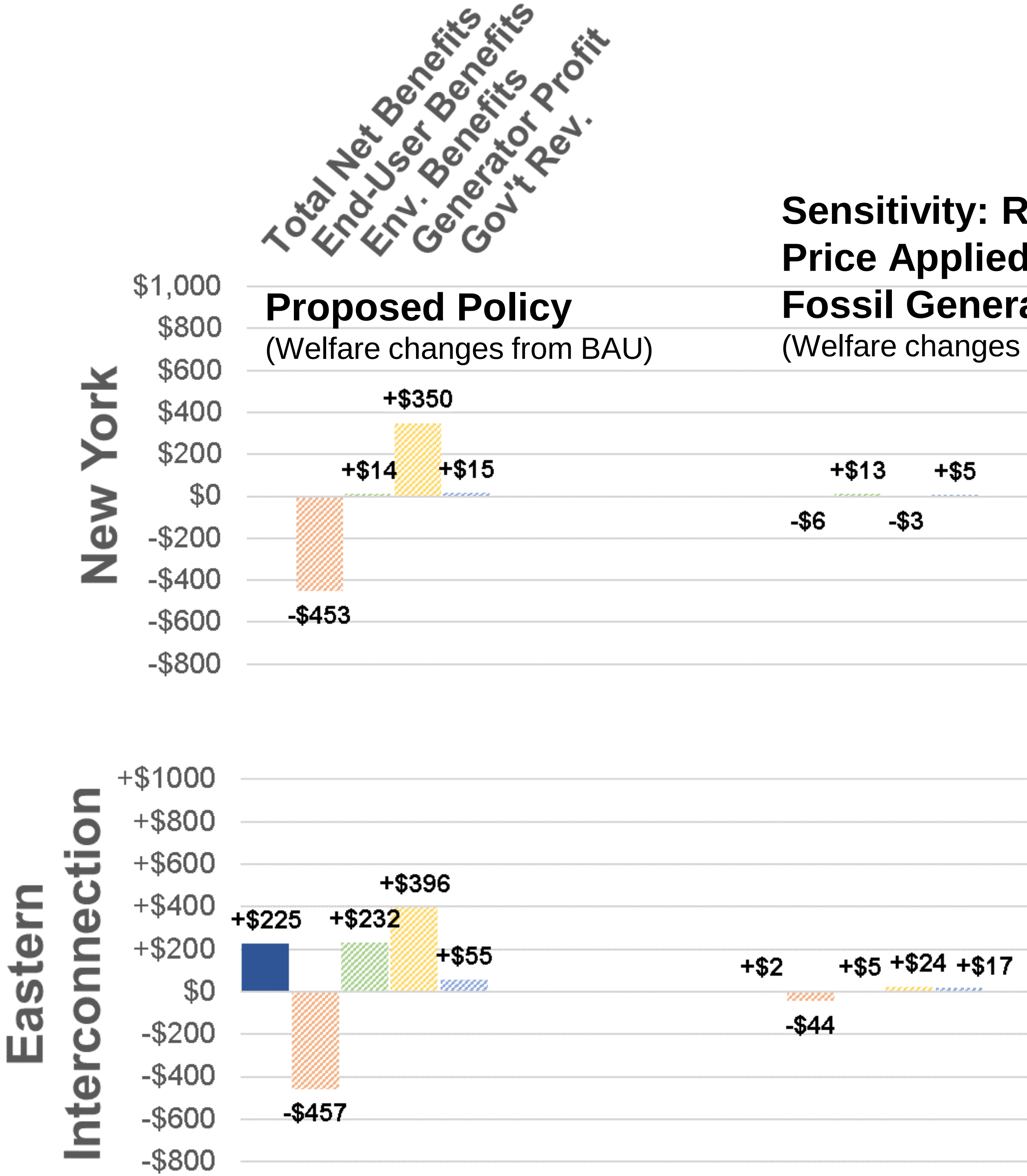
Carbon Price Revenues (2013$)

NY Carbon Price Revenue

	Emissions (thousand short tons)	Price	Revenue (2013$ thousands)
Total	23,599		$882,663
RGGI - SCC Units	23,044	$37	$857,012
SCC Units	555	$46	$25,651

Though applying the NY carbon price to NY generators that are exempt from RGGI produces most of the environmental benefits of the Policy, it **accounts for less than 3% of the carbon price payments**.

Our simulation results conform well with the observed average capacity factor of the NY generators that are exempt from RGGI as a result of having capacities < 25 MW. It was 10.4% in 2016 according to SNL data, with a RGGI price of approximately $4.50, and it is 14% in our 2025 BAU simulation results, with a RGGI price of approximately $12.50.



New York environmental benefits when applying the RGGI price to small NY generators are similar to those resulting from the Policy.

Other results are quite different from those resulting from the Policy.

Some Other Ways the Policy Could Affect Emissions and Costs, Not in Our Analysis

- By example, could persuade other states to adopt CO_2 emission prices (unless it ends up looking bad)
- By reducing the RGGI allowance price, could convince RGGI states to make RGGI more stringent in the future than it would otherwise have been
- Could continue to reward nuclear plants for their zero emissions beyond the potential end of ZEC policy, and that could encourage more stringent RGGI in the future
- Could affect investor confidence, positively or negatively

Key Takeaways Regarding Net Benefits

*Estimated Effects of Policy in 2025 (in 2013$)**

- Estimated environmental benefit of $232 million/year, mostly from slight reduction in non-NY emissions
- Estimated net total benefit of $225 million/year
- Estimated NY end-user pocketbook welfare costs of $453 million/year, which is 0.29 cents/kWh or $2.90/MWh
- Somewhat smaller profit gain for NY generators

*To convert to 2025 dollars, multiply by 1.24.

Key Takeaways Regarding NY Emissions & RPS

Estimated Effects of Policy in 2025 (in 2013$)

- 0.9% reduction in NY generator CO_2 emissions, 0.2% increase in generation
- This 1.1% reduction in NY power sector CO_2 emission intensity is primarily from equalizing the CO_2 emission price applied to RGGI-exempt NY fossil generators
- $14 million/year reduction in damage from NY generator emissions
- RPS still binds, so no change in amount of NY renewable generation

Key Takeaways Regarding Price Effects

Estimated Effects of Policy in 2025 (in 2013$)

- LBMP effect of ~$16 in zones A-E, ~$18 in F-I, and ~$19 in J&K, per MWh
- Reduces REC price from $37 to $22 per MWh
- Reduces ZEC price from $11 to $0 per MWh
- Increases NY (upstate) nuclear unit revenue from $52 to $54 per MWh

- Changes RGGI price little, *increasing* it from $9.10 to $9.59
- RGGI Emission and Cost Containment Reserves not triggered

END

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Appendix

Most Recently Completed E4ST Publications

D. Shawhan and P. Picciano, "**Costs and Benefits of Saving Unprofitable Generators: A Simulation Case Study for US Coal and Nuclear Power Plants**." Forthcoming in *Energy Policy*. Working paper version at http://www.rff.org/research/publications/costs-and-benefits-saving-unprofitable-generators-simulation-case-study-us. Cited in FERC ruling document on the "Grid Resiliency Pricing Rule." Cited in *The New York Times*, *The Houston Chronicle*, *The Washington Post*, *The Globe and Mail*, VOX, Axios Generate, & other pubs.

D. Shawhan, "**Co-Emission and Welfare Effects of Electricity Policy and Market Changes: Results from the EMF 32 Model Intercomparison Project**." *Energy Economics*, June 2018.

C. Fischer, B. Mao, and D. Shawhan, "**Trade between Mass- and Rate-Based Regulatory Regimes: Bad for Emissions?**" *Energy Economics,* June 2018.

Bistline, John, Daniel Shawhan, Geoffrey Blanford, Francisco de la Chesnaye, Biao Mao, Nidhi Santen, Ray Zimmerman, Alan Krupnick, "**Systems Analysis in Electric Power Sector Modeling: Evaluating Model Complexity for Long-Range Planning**." Electric Power Research Institute and Resources for the Future, October 2017. http://www.rff.org/research/publications/systems-analysis-electric-power-sector-modeling-evaluating-model-complexity.

Shawhan, Daniel, and Paul Picciano. "Retirements and Funerals: The Emission, Mortality, and Coal-Mine Employment Effects of a Two-Year Delay in Coal and Nuclear Power Plant Retirements." Resources for the Future working paper 18-18, July 5, 2018. http://www.rff.org/research/publications/retirements-and-funerals-emission-mortality-and-coal-mine-employment-effects. Cited in Bloomberg, *The Houston Chronicle*, *The Columbus Dispatch*, Axios, *The Washington Examiner*, Utility Dive, and other publications.

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Selected Publications, p. 2

Biao Mao, Daniel Shawhan, Ray Zimmerman, Jubo Yan, Yujia Zhu, William Schulze, Richard Schuler, Daniel Tylavsky. "**The Engineering, Economic and Environmental Electricity Simulation Tool (E4ST): Description and an Illustration of its Capability and Use as a Planning/Policy Analysis Tool.**" Proceedings of the 49th Hawaii International Conference on System Sciences (HICSS), Koloa, HI, 2016, pp. 2317-2325. (peer review information at http://www.hicss.org/components.htm) DOI: 10.1109/HICSS.2016.290 Won best paper award in the Electric Energy Systems track.

Yujia Zhu; Tylavsky, D., "**An optimization based network reduction method with generator placement**," in North American Power Symposium (electronic journal), pp.1-6, 4-6 Oct. 2015.
DOI: 10.1109/NAPS.2015.7335172

Di Shi; Tylavsky, D.J., "**A Novel Bus-Aggregation-Based Structure-Preserving Power System Equivalent**," in Power Systems, IEEE Transactions on, vol.30, no.4, pp.1977-1986, July 2015.
DOI: 10.1109/TPWRS.2014.2359447

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D. Shi, D. Shawhan, N. Li, D. J. Tylavsky, J. Taber, R. Zimmerman, "**Optimal Generation Investment Planning: Part 1: Network Equivalents**," North American Power Symposium (electronic journal), Champaign, Illinois, September 2012, 6 pages.
DOI: 10.1109/NAPS.2012.6336375

Selected Publications, p. 4

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DOI: 10.1109/NAPS.2012.6336374

Y. Qi, D. Shi, D. J. Tylavsky, "**Impact of Assumptions on DC Power Flow Accuracy**," North American Power Symposium (electronic journal), Champaign, Illinois, September 2012, 6 pages.
DOI: 10.1109/NAPS.2012.6336395

D. Shi, D. J. Tylavsky, "**An Improved Bus Aggregation Technique for Generating Network Equivalents**," 2012 IEEE Power Engineering Society General Meeting, San Diego, CA, Jul. 2012, 8 pages.
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R. D. Zimmerman, C. E. Murillo-Sánchez, and R. J. Thomas, "**MATPOWER: Steady-State Operations, Planning and Analysis Tools for Power Systems Research and Education**," Power Systems, IEEE Transactions on, vol. 26, no. 1, pp. 12-19, Feb. 2011.
DOI: 10.1109/TPWRS.2010.2051168

Why the E4 Simulation Tool

Proper projection or optimization often requires prediction of *system-wide*, *society-wide*, and *long-term* effects

System-wide	Society-wide	Long-term
• Determines flows according to laws of physics	• Emissions, their transport, and health effects	• Simultaneously predicts operation, investment, and retirement

Other Strengths of the E4 Simulation Tool

- Demand function at each node (and growth)
- Can be used with model of any grid
- Software and US & Canadian data are transparent, publicly available, & modifiable

The Simulation Objective

$$\max_{p_{ijk}, I_{ij}, R_{ij}} \left\{ \sum_i \sum_j \left[\begin{matrix} \left(\sum_k H_k \left(B_{jk} - \left(c_i^F + a_{jk} e_i \right) p_{ijk} \right) \right) \\ - \left(c_i^T \left(p_{ij}^0 + I_{ij} - R_{ij} \right) + c_i^I I_{ij} \right) \end{matrix} \right] \right\}$$

subject to

$$p_{ij}^0 + I_{ij} - R_{ij} \geq p_{ijk}$$

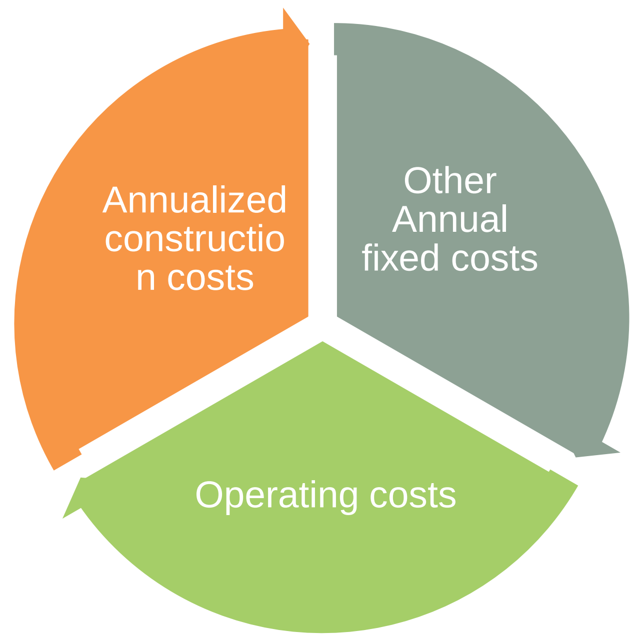
$$p_{ijk} \geq \alpha_i^{\min} \left(p_{ij}^0 + I_{ij} - R_{ij} \right)$$

$$K_{ij} > I_{ij}$$

$$\sum_i p_{ijk} - L_{jk} - \sum_{j'} S_{jj'} (\Theta_{jk} - \Theta_{j'k}) = 0$$

$$F_{jj'} > \left| S_{jj'} (\Theta_{jk} - \Theta_{j'k}) \right|$$

Like a system operator, E4ST finds the combination of plant construction, retirement, and operation that maximizes **consumer benefits** minus



subject to meeting load and respecting network constraints

A Bit More About the Inputs

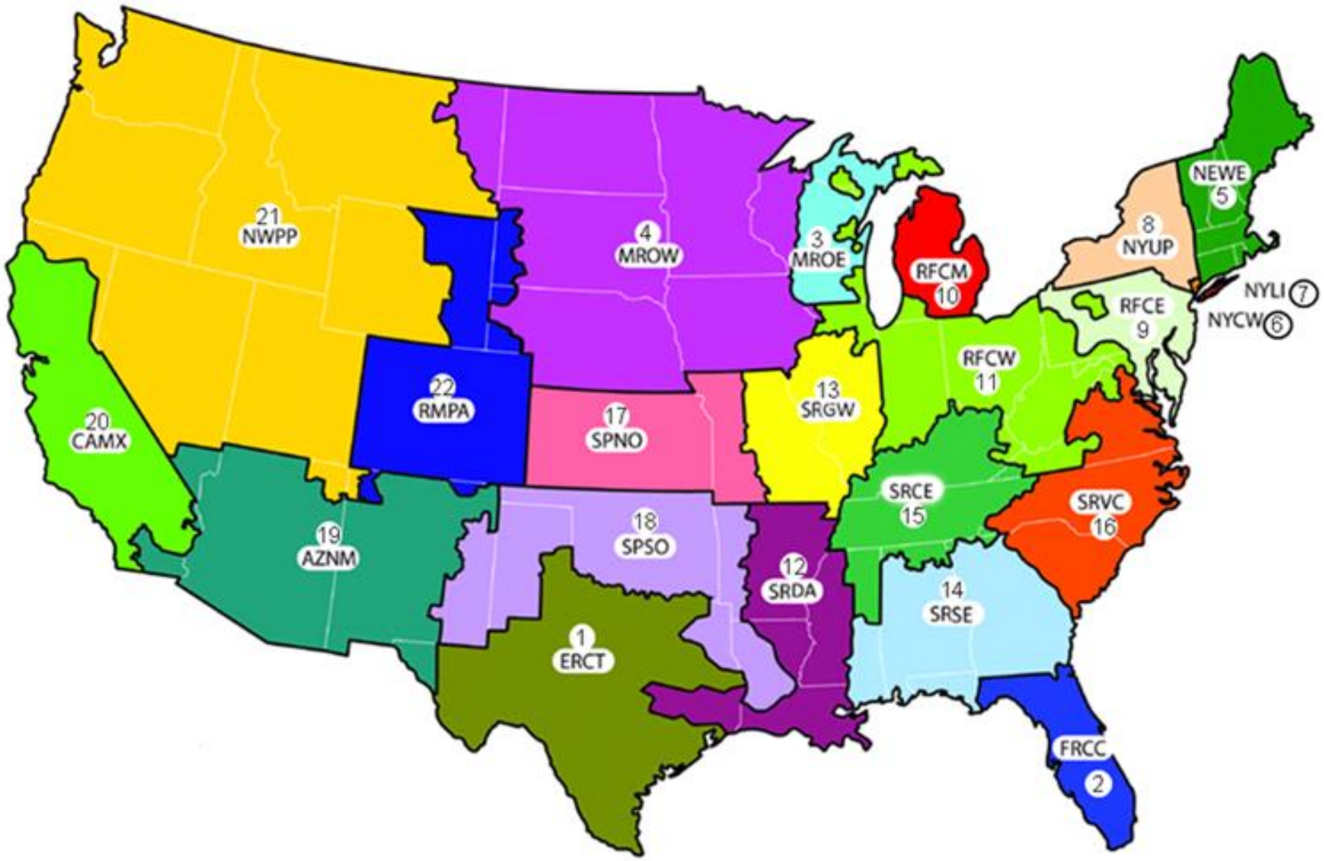
Generator and Demand Data Overview

Generators: Capacities, marginal costs, fixed costs, emission rates, locations, smokestack heights combined from 14 sources. SNL, IPM, EIA, EPA, and Energy Visuals Inc.

~40 representative hours represent joint distribution of demand, generator availability, wind, and solar

Cost Data for New Generators

Technology-specific capital costs, heat rates, fixed/variable costs across 22 regions (AEO 2018)



Assumed Wind and Solar Capital Costs

Wind and Solar Capital Costs in 2025 (2013$/KW)

Zone	Solar PV	Onshore Wind
A	$1,801	$2,360
B	$1,801	$2,360
C	$1,801	$2,360
D	$1,801	$2,360
E	$1,801	$2,360
F	$1,801	$2,360
G	$1,905	NA
H	$1,905	NA
I	$1,905	NA
J	$2,973	NA
K	$1,905	NA

Hypotheses About the Effects of NY C Adder

We have tested some of them in this this analysis

Ways the NY C adder could reduce expected emissions

1. By example, may persuade other states to adopt more aggressive emission reduction policies (unless it ends up looking bad)
2. Have a non-zero probability of moving the RGGI market outcome leftward on the ECR step, the price floor, or the RGGI soft price ceiling.
3. By increasing RGGI emission reduction supply curve (emission allowance demand curve), i.e. by making emission reductions look cheaper, may convince RGGI to make RGGI more stringent in the future than it would otherwise have been
4. Could continue to reward nuclear plants for their zero emissions beyond the potential end of ZEC policy, and that could encourage more stringent RGGI in the future
5. Could reduce coal generation outside of NY by making electricity prices outside of New York more variable

Ways NY C adder could either increase or decrease expected emissions

- Might increase leakage to outside of RGGI, because it would cause there to be a high CO_2 price (instead of a low one, as at present) next to states with a lot of spare coal-fired capacity. However, NY would (under the proposal) have a pricing scheme to reduce leakage.

Ways NY C adder could increase expected costs

1. Deviation from equimarginal principle, geographically: Would cause high-cost emission reduction actions to be taken in NY, instead of low-cost actions elsewhere in RGGI
2. Would continue the subsidy to nuclear plants beyond the potential end of ZEC policy, which may encourage more stringent emission reduction policies. If it induced RGGI or other states to have more stringent emission reduction policies, that increased stringency would have costs.

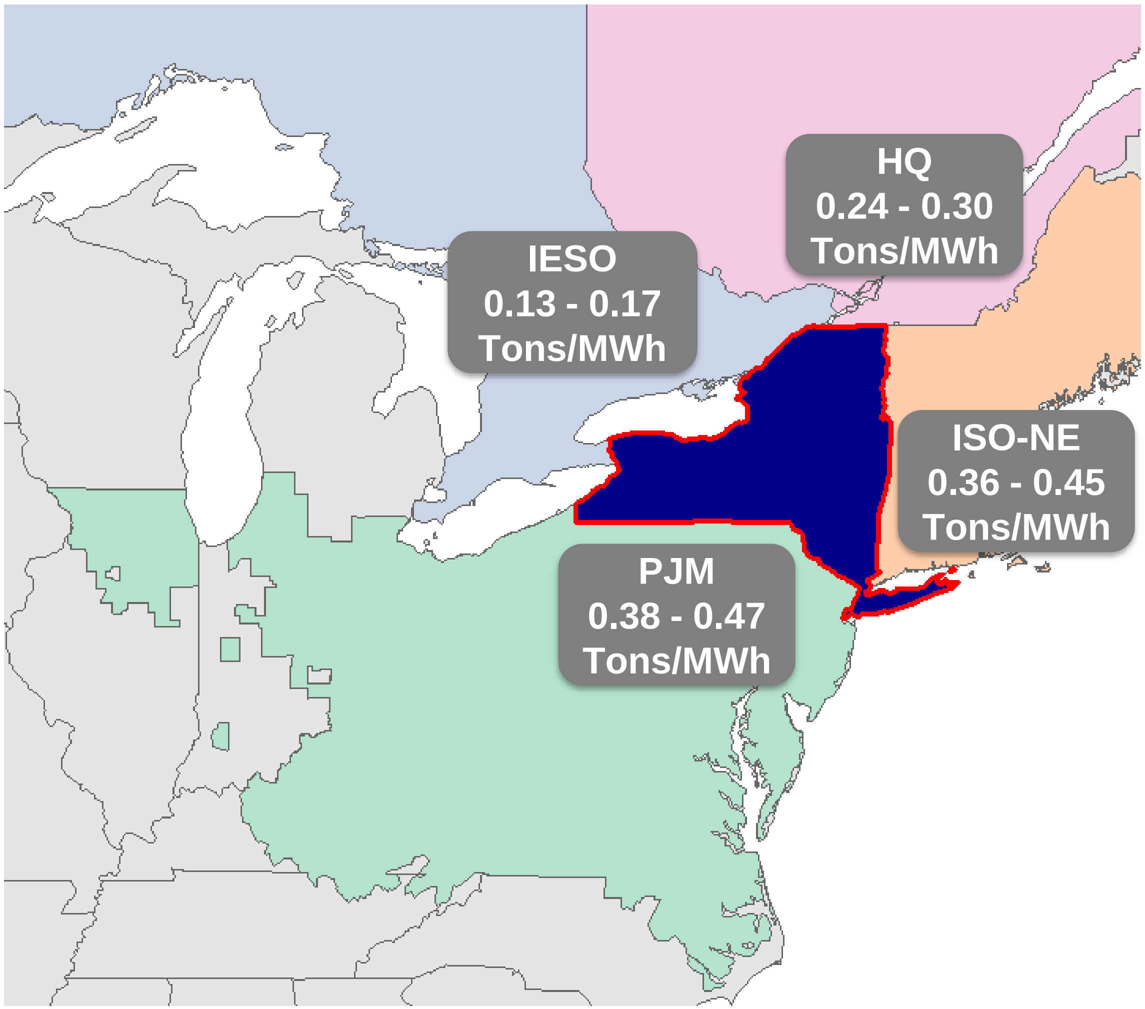
Ways NY C adder could decrease expected costs

- By applying the same emission price to RGGI-exempt fossil units as to units subject to RGGI. This ends a deviation from the equimarginal principle.

Additional Results

Implied Border Marginal Emission Rates

Annual Average in 2025 (2013$)



These are the average implied marginal emission rates in New York associated with decreasing net imports from a given neighboring system.

Implied MER [Ton/MWh] =

Border Price [$/MWh] / Carbon Price [$/Ton]

The range provided is MER calculated using two different carbon prices:

[SCC] – [SCC Minus RGGI]

Effects of Policy on LBMP and ICAP Price

Zonal LBMP (2013$/MWh), 2025

	BAU	Policy	Change
A	$20.52	$36.24	$15.71
B	$24.18	$40.28	$16.10
C	$22.69	$38.45	$15.76
D	$23.62	$39.38	$15.76
E	$22.95	$38.34	$15.40
F	$28.39	$46.31	$17.93
G	$26.57	$44.01	$17.44
H	$26.66	$44.39	$17.73
I	$26.71	$44.22	$17.51
J	$28.88	$47.93	$19.05
K	$29.31	$48.48	$19.17
NY-Wide	**$26.4**	**$44.1**	**$17.7**
EI-Wide	**$29.3**	**$30.1**	**$0.8**

NYCA-Wide Capacity Price (2013$/MW), 2025

	BAU	Policy	Change
	$11.38	$9.33	-$2.04

Implied Hourly Border Prices (2013$/MWh)

Representative Hour	Hours	Month	Day	Hour	Season	PJM	ISO-NE	Ontario	Quebec
1	4	8	2	17	Summer	1.7 - 2.11	0.91 - 1.14	2.19 - 2.72	0.03 - 0.04
2	5	8	2	14	Summer	0.53 - 0.65	0.08 - 0.1	0.14 - 0.17	0.36 - 0.45
3	6	7	17	15	Summer	0.68 - 0.84	0.71 - 0.88	0.27 - 0.34	0.27 - 0.33
4	7	8	2	13	Summer	0.26 - 0.33	0.08 - 0.1	0.12 - 0.14	0.28 - 0.35
5	8	8	3	16	Summer	0.53 - 0.65	0.57 - 0.71	0.08 - 0.1	0.45 - 0.56
6	9	7	17	13	Summer	0.45 - 0.57	0.53 - 0.66	0.68 - 0.84	0.27 - 0.34
7	10	7	19	17	Summer	0.49 - 0.6	0.47 - 0.59	0.11 - 0.13	0.45 - 0.55
8	11	7	26	17	Summer	0.45 - 0.57	0.54 - 0.67	0.3 - 0.37	0.24 - 0.3
9	212	7	25	16	Summer	0.45 - 0.56	0.45 - 0.56	0.05 - 0.06	0.42 - 0.52
10	212	8	17	12	Summer	0.43 - 0.54	0.34 - 0.43	0.27 - 0.34	0.24 - 0.29
11	212	6	8	18	Summer	0.38 - 0.48	0.38 - 0.47	0.18 - 0.23	0.24 - 0.29
12	212	9	6	13	Fall	0.38 - 0.48	0.37 - 0.46	0.06 - 0.07	0.24 - 0.29
13	212	5	23	21	Spring	0.39 - 0.49	0.41 - 0.51	0.02 - 0.03	0.23 - 0.29
14	212	4	17	18	Spring	0.4 - 0.5	0.41 - 0.51	0.13 - 0.16	0.25 - 0.31
15	212	9	20	19	Fall	0.4 - 0.5	0.38 - 0.47	0.06 - 0.07	0.24 - 0.29
16	212	11	21	13	Fall	0.38 - 0.48	0.38 - 0.48	0.05 - 0.07	0.24 - 0.3
17	211	11	15	14	Fall	0.38 - 0.47	0.37 - 0.46	0.14 - 0.17	0.23 - 0.29
18	211	5	11	18	Spring	0.37 - 0.46	0.38 - 0.47	0.14 - 0.18	0.24 - 0.3
19	211	5	16	15	Spring	0.4 - 0.5	0.41 - 0.51	0.02 - 0.02	0.24 - 0.29
20	211	10	27	21	Fall	0.38 - 0.48	0.39 - 0.48	0.14 - 0.17	0.25 - 0.31
21	412	8	16	11	Summer	0.48 - 0.6	0.35 - 0.43	0.16 - 0.2	0.24 - 0.29
22	412	8	30	9	Summer	0.39 - 0.49	0.37 - 0.46	0.13 - 0.16	0.23 - 0.29
23	411	5	24	22	Spring	0.35 - 0.44	0.37 - 0.46	0.14 - 0.18	0.23 - 0.29
24	411	5	20	16	Spring	0.33 - 0.41	0.33 - 0.41	0.16 - 0.2	0.23 - 0.29
25	411	9	8	8	Fall	0.39 - 0.48	0.37 - 0.46	0.13 - 0.16	0.25 - 0.31
26	411	10	8	20	Fall	0.39 - 0.49	0.41 - 0.51	0.13 - 0.17	0.25 - 0.32
27	411	10	21	18	Fall	0.38 - 0.48	0.4 - 0.5	0.15 - 0.18	0.24 - 0.29
28	411	3	25	17	Spring	0.38 - 0.48	0.4 - 0.5	0.15 - 0.18	0.23 - 0.29
29	300	8	4	3	Summer	0.43 - 0.53	0.37 - 0.46	0.03 - 0.04	0.23 - 0.29
30	300	8	11	3	Summer	0.34 - 0.43	0.34 - 0.43	0.15 - 0.19	0.24 - 0.29
31	300	2	11	6	Spring	0.34 - 0.43	0.33 - 0.41	0.14 - 0.17	0.24 - 0.3
32	300	6	3	24	Summer	0.34 - 0.43	0.34 - 0.42	0.16 - 0.2	0.24 - 0.29
33	300	2	24	3	Winter	0.34 - 0.43	0.34 - 0.43	0.15 - 0.19	0.24 - 0.3
34	300	9	15	1	Fall	0.33 - 0.41	0.32 - 0.4	0.16 - 0.2	0.23 - 0.29
35	300	4	22	24	Spring	0.36 - 0.44	0.32 - 0.4	0.16 - 0.2	0.23 - 0.29
36	300	1	3	3	Winter	0.32 - 0.4	0.29 - 0.37	0.16 - 0.2	0.23 - 0.29
37	300	10	7	2	Fall	0.31 - 0.38	0.28 - 0.35	0.17 - 0.21	0.23 - 0.29
38	168	3	31	3	Spring	0.29 - 0.36	0.29 - 0.36	0.16 - 0.19	0.23 - 0.28
Hour-Weighted Annual Average						**0.38 - 0.47**	**0.36 - 0.45**	**0.13 - 0.17**	**0.24 - 0.3**

RESOURCES FOR THE FUTURE

Appendix

Implied Hourly Marginal Emission Rates (Tons/MWh)

Representative Hour	Hours	Month	Day	Hour	Season	PJM	ISO-NE	Ontario	Quebec
1	4	8	2	17	Summer	1.6 - 2.11	0.86 - 1.14	2.07 - 2.72	0.03 - 0.04
2	5	8	2	14	Summer	0.5 - 0.65	0.08 - 0.1	0.13 - 0.17	0.34 - 0.45
3	6	7	17	15	Summer	0.64 - 0.84	0.67 - 0.88	0.26 - 0.34	0.25 - 0.33
4	7	8	2	13	Summer	0.25 - 0.33	0.08 - 0.1	0.11 - 0.14	0.27 - 0.35
5	8	8	3	16	Summer	0.5 - 0.65	0.54 - 0.71	0.07 - 0.1	0.43 - 0.56
6	9	7	17	13	Summer	0.43 - 0.57	0.5 - 0.66	0.64 - 0.84	0.25 - 0.34
7	10	7	19	17	Summer	0.46 - 0.6	0.45 - 0.59	0.1 - 0.13	0.42 - 0.55
8	11	7	26	17	Summer	0.43 - 0.57	0.51 - 0.67	0.28 - 0.37	0.23 - 0.3
9	212	7	25	16	Summer	0.42 - 0.56	0.42 - 0.56	0.04 - 0.06	0.4 - 0.52
10	212	8	17	12	Summer	0.41 - 0.54	0.32 - 0.43	0.26 - 0.34	0.22 - 0.29
11	212	6	8	18	Summer	0.36 - 0.48	0.36 - 0.47	0.17 - 0.23	0.22 - 0.29
12	212	9	6	13	Fall	0.36 - 0.48	0.35 - 0.46	0.06 - 0.07	0.22 - 0.29
13	212	5	23	21	Spring	0.37 - 0.49	0.38 - 0.51	0.02 - 0.03	0.22 - 0.29
14	212	4	17	18	Spring	0.38 - 0.5	0.39 - 0.51	0.12 - 0.16	0.24 - 0.31
15	212	9	20	19	Fall	0.38 - 0.5	0.35 - 0.47	0.06 - 0.07	0.22 - 0.29
16	212	11	21	13	Fall	0.36 - 0.48	0.36 - 0.48	0.05 - 0.07	0.23 - 0.3
17	211	11	15	14	Fall	0.36 - 0.47	0.35 - 0.46	0.13 - 0.17	0.22 - 0.29
18	211	5	11	18	Spring	0.35 - 0.46	0.36 - 0.47	0.14 - 0.18	0.23 - 0.3
19	211	5	16	15	Spring	0.38 - 0.5	0.39 - 0.51	0.02 - 0.02	0.22 - 0.29
20	211	10	27	21	Fall	0.36 - 0.48	0.37 - 0.48	0.13 - 0.17	0.23 - 0.31
21	412	8	16	11	Summer	0.45 - 0.6	0.33 - 0.43	0.15 - 0.2	0.22 - 0.29
22	412	8	30	9	Summer	0.37 - 0.49	0.35 - 0.46	0.12 - 0.16	0.22 - 0.29
23	411	5	24	22	Spring	0.33 - 0.44	0.35 - 0.46	0.13 - 0.18	0.22 - 0.29
24	411	5	20	16	Spring	0.31 - 0.41	0.31 - 0.41	0.15 - 0.2	0.22 - 0.29
25	411	9	8	8	Fall	0.37 - 0.48	0.35 - 0.46	0.12 - 0.16	0.24 - 0.31
26	411	10	8	20	Fall	0.37 - 0.49	0.39 - 0.51	0.13 - 0.17	0.24 - 0.32
27	411	10	21	18	Fall	0.36 - 0.48	0.38 - 0.5	0.14 - 0.18	0.22 - 0.29
28	411	3	25	17	Spring	0.36 - 0.48	0.38 - 0.5	0.14 - 0.18	0.22 - 0.29
29	300	8	4	3	Summer	0.4 - 0.53	0.35 - 0.46	0.03 - 0.04	0.22 - 0.29
30	300	8	11	3	Summer	0.32 - 0.43	0.32 - 0.43	0.15 - 0.19	0.22 - 0.29
31	300	2	11	6	Spring	0.33 - 0.43	0.31 - 0.41	0.13 - 0.17	0.23 - 0.3
32	300	6	3	24	Summer	0.32 - 0.43	0.32 - 0.42	0.15 - 0.2	0.22 - 0.29
33	300	2	24	3	Winter	0.33 - 0.43	0.32 - 0.43	0.14 - 0.19	0.23 - 0.3
34	300	9	15	1	Fall	0.31 - 0.41	0.3 - 0.4	0.15 - 0.2	0.22 - 0.29
35	300	4	22	24	Spring	0.34 - 0.44	0.3 - 0.4	0.15 - 0.2	0.22 - 0.29
36	300	1	3	3	Winter	0.3 - 0.4	0.28 - 0.37	0.15 - 0.2	0.22 - 0.29
37	300	10	7	2	Fall	0.29 - 0.38	0.27 - 0.35	0.16 - 0.21	0.22 - 0.29
38	168	3	31	3	Spring	0.28 - 0.36	0.27 - 0.36	0.15 - 0.19	0.21 - 0.28
Hour-Weighted Annual Average						**0.36 - 0.47**	**0.34 - 0.45**	**0.13 - 0.17**	**0.23 - 0.3**

RESOURCES FOR THE FUTURE

Effects of Policy on NY Net Imports

Representative Hour	Hours	Month	Day	Hour	Season	Total	PJM	ISO-NE	Ontario	Quebec
1	4	8	2	17	Summer	-1,153	-164	-1,268	-101	380
2	5	8	2	14	Summer	139	-26	0	165	0
3	6	7	17	15	Summer	556	925	-424	56	-1
4	7	8	2	13	Summer	1,292	801	0	491	-1
5	8	8	3	16	Summer	428	-203	-33	75	591
6	9	7	17	13	Summer	966	878	90	0	-3
7	10	7	19	17	Summer	5,991	6,030	-39	0	0
8	11	7	26	17	Summer	5,699	5,810	-108	0	-3
9	212	7	25	16	Summer	98,499	57,367	41,132	0	0
10	212	8	17	12	Summer	-10,876	1,285	-12,146	0	-16
11	212	6	8	18	Summer	-5,466	7,708	-13,158	0	-16
12	212	9	6	13	Fall	-18,310	-5,463	-12,838	0	-9
13	212	5	23	21	Spring	-11,917	-8,690	-5,183	1,977	-21
14	212	4	17	18	Spring	-15,736	-32,959	4,189	1,977	11,056
15	212	9	20	19	Fall	-77,024	-29,024	-3,631	1,977	-46,346
16	212	11	21	13	Fall	-95,073	-7,255	-1,924	1,977	-87,872
17	211	11	15	14	Fall	5,245	-15,237	-2,479	1,968	20,994
18	211	5	11	18	Spring	-25,679	-43,530	-10,757	1,968	26,640
19	211	5	16	15	Spring	-14,673	-8,174	-8,457	1,968	-9
20	211	10	27	21	Fall	-15,600	-19,341	-2,774	1,968	4,547
21	412	8	16	11	Summer	-1,352	-9,965	8,621	0	-9
22	412	8	30	9	Summer	-19,891	-4,008	-18,216	3,843	-1,511
23	411	5	24	22	Spring	-43,530	-52,710	7,495	3,834	-2,149
24	411	5	20	16	Spring	-72,706	-43,451	3,465	3,834	-36,554
25	411	9	8	8	Fall	-42,315	-70,941	7,913	3,834	16,880
26	411	10	8	20	Fall	-47,404	1,137	-31,122	3,834	-21,253
27	411	10	21	18	Fall	-24,127	-15,153	-10,903	3,834	-1,905
28	411	3	25	17	Spring	14,932	13,624	-24,248	3,834	21,722
29	300	8	4	3	Summer	60,600	-12,153	-8,545	2,798	78,500
30	300	8	11	3	Summer	-31,741	-34,403	-527	2,798	392
31	300	2	11	6	Spring	32,129	32,357	2,530	2,798	-5,555
32	300	6	3	24	Summer	-5,009	-10	-8,096	2,798	299
33	300	2	24	3	Winter	614	29,477	-7,570	2,798	-24,092
34	300	9	15	1	Fall	47,605	-49	2,529	2,798	42,326
35	300	4	22	24	Spring	-16,053	-1	2,529	2,798	-21,380
36	300	1	3	3	Winter	63,780	-17,606	2,529	2,798	76,059
37	300	10	7	2	Fall	1,403	-1	2,529	2,798	-3,924
38	168	3	31	3	Spring	-60,611	-13,137	-2,597	1,567	-46,444
	Annual Total					**-316,368**	**-286,253**	**-101,491**	**70,063**	**1,313**

Breakdown of Policy Effect on NY End-Users, With and Without Price-Responsive Load

Change from BAU in 2025 (2013$ millions)

NY End-User Benefit Components		**Without PRL**	**With PRL**	**Delta**
Payments by End-Users				
Energy Payments	-	$2738	$2663	-$75
Capacity Payments	-	-$645	-$458	$187
Tier 1 REC Payments	-	-$254	-$264	-$9
ZEC Payments	-	-$296	-$290	$5
Rebates to End-Users				
Internal Congestion Revenue	+	$159	$124	-$35
Border Congestion and Import Charge Revenue*	+	$48	$38	-$10
Internal Carbon Adder Revenue**	+	$883	$875	-$8
End-User Net Benefits		**-$453**	**-$615**	**-$161**

* Net revenue both from the Policy’s border charge/credit and from cross-border transmission congestion. We assume that revenue is split fifty-fifty between NY and the bordering systems. The reader can easily modify this split assumption and the calculation.

** Revenue from the Policy's charge on NY power plant fossil CO_2 emissions.

These do not include environmental benefits to end-users, which are positive.