Analysis of a New York Carbon Charge (Updated)

PRESENTED TO
IPPTF

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THE Brattle GROUP

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12/21/2018 Updates

- Added slide 9 on economic efficiency gains
- Added slide 11 on change in annual NY customer costs
- Corrected typo on slide 19 table
- Clarified discussion of AC Transmission on slide 21
- Various minor edits

11/27/2018 Updates

- Analyzed carbon charge-induced repowering, effects on NOx emissions, and delayed construction of new transmission
- Updated MAPS-based customer cost analysis
  - Added 2022 scenario
  - Revised quantity of contracted RECs for "claw-back" calculation
  - Revised 2030 nuclear retention assumptions
- Corrected scenario assumptions on slide 36
- An updated version of the spreadsheet with 2022 modeling results and buildup tables has also been posted on the IPPTF Meeting Materials website

Agenda

Study Motivation, Scope, and Approach

Additional Analyses

Assessment of the Effects of Carbon Charges on Customer Costs (NYCA-wide)

Analytical Details (including Zonal Effects)

Motivation for Carbon Pricing

Provide a market-oriented approach to bridge state policies & NYISO markets

- Addresses negative energy pricing from renewables as penetration increases
- Lessens pressure for out-of-market incentives for non-renewable resources
- Lessens pressure for more aggressive buyer-side mitigation measures that could deter policy-supported resources or result in costly excess capacity

Provide transparent price signals reflecting carbon externality

- Helps achieve New York State decarbonization goals efficiently
- Aligns commitment and dispatch with state policy goals
- Signals investment for reducing carbon, including innovative solutions beyond CES
- Fine-tunes solutions with granular prices, e.g., siting of new renewables, storage operation

Carbon Pricing Straw Proposal and Analysis

Key Elements of Straw Proposal

- Add a carbon charge to NYISO's commitment, dispatch, and settlement
- Carbon price determined by the NYPSC (presumably consistent w/ its social cost of carbon)
- Return residuals from emitting resources to customers

Scope of Analysis

- Estimate effects on <u>customer costs</u> and <u>emissions</u> from Carbon Pricing Straw Proposal
- Conducted under IPPTF Issue Track 5 Scope: Estimate Effects of Carbon Pricing
- NYISO retained Brattle to help conduct the analysis

Analytical Approach

- NYISO staff ran GE-MAPS to evaluate effects on dispatch, emissions, and LBMPs
- Evaluate effects in 2022, 2025 and 2030
  - Updated results in this presentation replace 2020 results with 2022 results
  - 2022 serves as an approximation of effects when carbon pricing is first implemented
- Base case reflects "most likely" conditions with CES and RGGI and other existing policies (alternative scenarios shown at end)
- Freeze hourly external transactions (MWh) from base case
  - Consistent with Straw Proposal
  - Result is the economics of external transactions unaffected by carbon
- Change cases add: (1) carbon charges and (2) dynamic supply responses
- Compare change cases to base case without carbon charge

Conclusions: Economic Efficiency Gains

Internalizing a carbon charge would invite a broad range of solutions to compete to meet decarbonization goals cost-effectively, which should improve economic efficiency over existing policies alone

The proposed design helps prevent distortions at NYISO's seams that could reduce economic efficiency gains

- Proposed border pricing approach addresses the risk of distortionary leakage to neighbors
- Cross-sectoral distortions likely small, as the effect on customer costs is minimal and unlikely to deter electrification

We estimate economic savings of \$7m/yr in 2022, rising to \$50m/yr by 2030

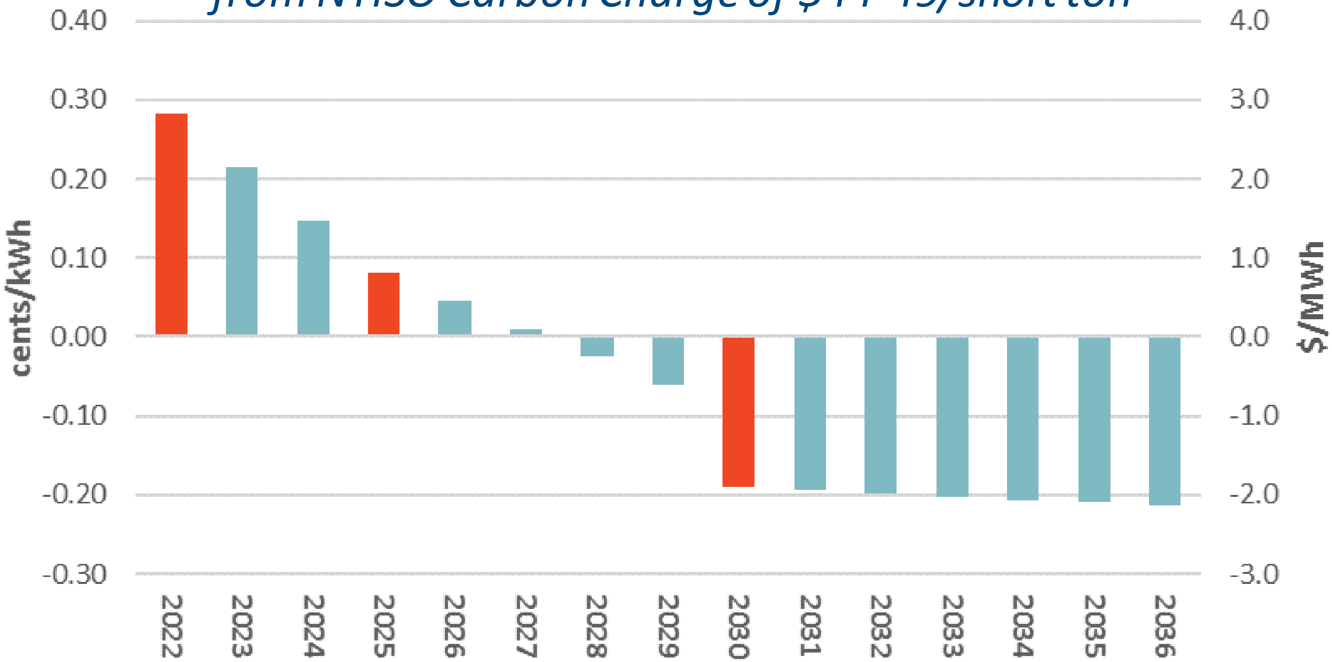
- A carbon charge reduces CO_2 emissions through measures that cost less than the SCC
- This can avoid costlier abatement measures such as procuring additional RECs
- In 2022, 0.64 million tons of carbon-charge-induced abatement could avoid 1.9 TWh of additional annual REC purchases at \$3/MWh (with a carbon charge), reducing total annual economic costs by \$7 million
- In 2030, 1.4 million tons of carbon-charge-induced abatement could avoid 4.2 TWh of additional annual REC purchases at \$12/MWh (with a carbon charge), reducing total annual economic costs by \$50 million

A separate question is how much of the economic gains are enjoyed by consumers vs. producers, and if higher energy prices transfer wealth from consumers to producers

Conclusions: Effects on Customer Costs

- Carbon charges would have a **minor effect** on customer costs
- In the long run, carbon charges could **reduce customer costs; estimates are conservative**
- Cost impacts assume customers are fully exposed to wholesale prices, which overstates the effect on customers who are hedged, especially in the short term

Estimated Change in Annual New York Customer Costs
from NYISO Carbon Charge of $44-49/short ton



Notes: Figure shows nominal dollars. Study years shown in **red.** Annual estimates linearly interpolate between 2022 and 2025 Reference assumptions, and between 2025 and an estimated 2029 case (based on other simulations); 2030 Reference assumptions held constant in real terms beyond 2030.

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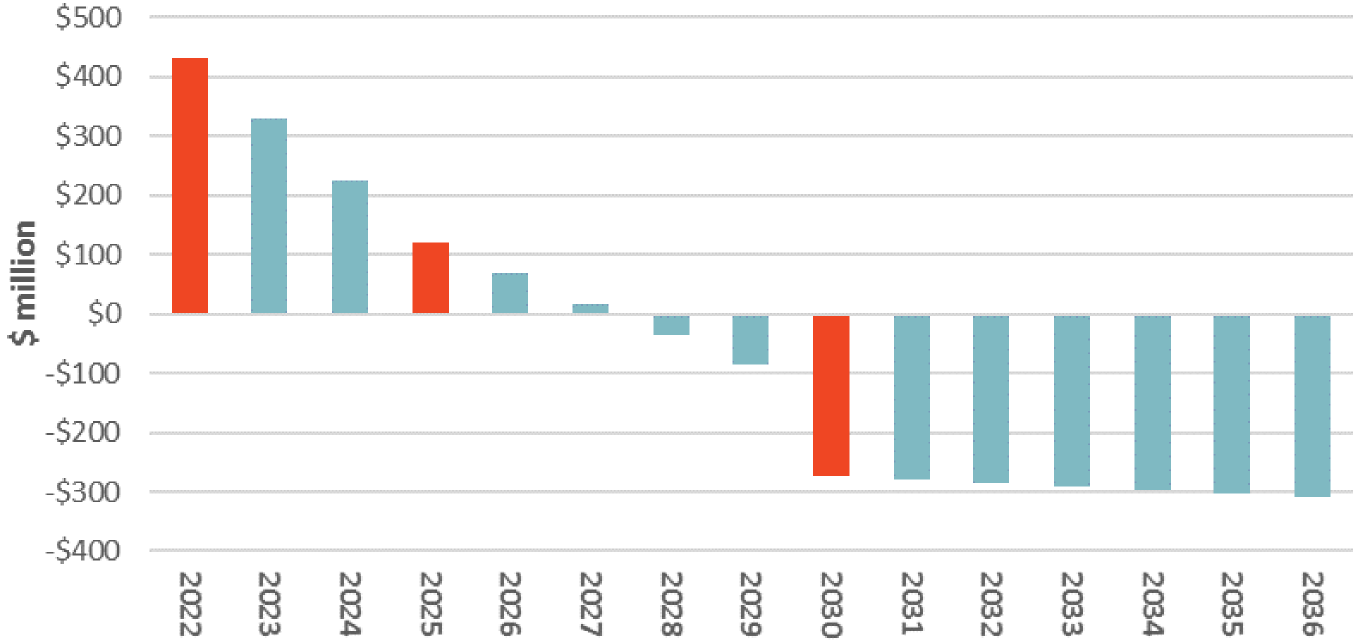

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Conclusions: Effects on Customer Costs

Although a carbon charge increases LBMPs, there are several offsetting customer benefits that we quantify…

- Customer credit from emitting resources
- Lower REC and ZEC prices
- Increased value of TCCs
- Shift of new renewables to regions with higher marginal CO_2 emissions to displace
- Possible retention of some Upstate nuclear in 2030
- Possible incremental investment in renewables
- Some incremental energy efficiency and conservation

…and several customer benefits we do not quantify (see slide 13)

Conclusions: Effects on Emissions

We estimate a carbon charge could reduce emissions of CO_2 and NOx

- Internal CO_2 emissions could fall 6% by 2030 (-1.4 million tons/yr from 21 million baseline)
- Statewide annual NOx emissions could fall by 365 tons by 2030
- Emission reductions primarily in Downstate locations
- Further reductions possible if carbon charge leads to repowering of Downstate steam units
- Emission reductions incremental to reductions already achieved by CES

Conclusions: Other Potential Benefits

Benefits could increase with more innovative emissions reductions the market might produce in response to prices (but not captured in the analysis), such as:

- Increased investment in low-cost renewable generation as technologies evolve
- Increased investment and activity of storage to move load from high to low-emitting hours
- Efficiency improvements to the existing fleet, and in any new investment in fossil generation
- Repowering of high-emitting aging capacity
- And other responses that the market may elicit which we have not imagined

Benefits could be much greater if carbon charges prevent conflicts between state programs and wholesale electricity markets

Other qualifiers:

- Conservatisms: assume customers 100% exposed to LBMPs; 0 ZEC benefit in 2020-22; assumed low elasticity of demand
- Estimated net costs could increase if MAPS understates prices/MERs
- Estimate net costs could change if the proposal changes

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Additional Analyses

Assessment of the Effects of Carbon Charges on Customer Costs (NYCA-wide)

Analytical Details (including Zonal Effects)

Introduction to Additional Analyses

At the request of stakeholders, we have extended the analysis and analyzed how a carbon charge could produce:

- Additional zero-emission resource retention in 2030
- Repowering of Downstate fossil steam and peaking capacity
- Sensitivity of results to potential delayed construction of Public Policy AC Transmission Project

Additional Zero-Emission Resource Retention in 2030

Under 2030 Reference assumptions:

- **Without a carbon charge,** over 2,000 MW of Upstate nuclear capacity retires due to license expirations and poor economics
  - Assume no possibility of retaining plants beyond 60-year license expiration
  - NMP2 (1,300 MW) stays online
- **With a carbon charge**
  - Assume a 50% chance of retaining one unit due to improved economics, an <u>expected value of 440 MW retained by a carbon charge</u>
  - ~1,200 MW of Upstate capacity still retires due to license expirations
  - NMP2 (1,300 MW) still stays online

Upon stakeholder request, we have reviewed these assumptions further

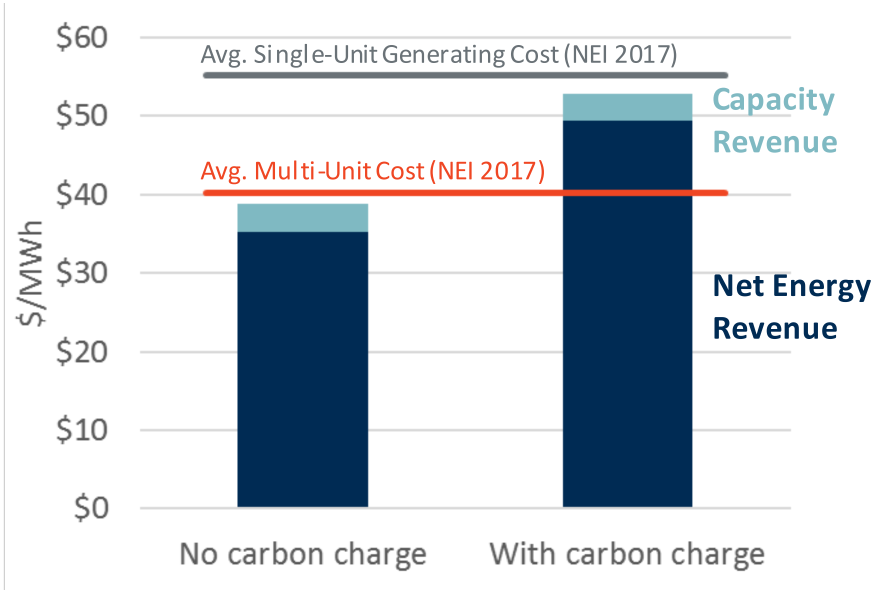
However, we continue to assume conservatively that all existing renewable resources without contracts are retained even without a carbon charge

Additional Zero-Emission Resource Retention in 2030

A carbon charge could retain more nuclear than previously assumed, because:

- Nuclear plants elsewhere have filed for license re-extensions, implying there may not be technical limitations to extending operations to 80 years
  - Turkey Point 3&4 and Peach Bottom 2&3 have SLR applications under review
  - Surrey 1&2 and North Anna 1&2 have filed intent to pursue SLR
- A carbon charge may improve economics such that net revenues exceed costs
- Therefore, if economics are favorable and units are in good physical condition, some Upstate NY nuclear units may apply for license extensions

Effect of Carbon Charge on Nuclear Revenue Under 2030 Reference Assumptions



Sources and Notes:
NRC SLR applications: https://www.nrc.gov/reactors/operating/licensing/renewal/subsequent-license-renewal.html
NEI costs escalated at 2% inflation to 2030$. NEI Nuclear by the Numbers: https://www.nei.org/CorporateSite/media/filefolder/resources/fact-sheets/nuclear-by-the-numbers-20180412.pdf

Additional Zero-Emission Resource Retention in 2030

- Given this new information, we have increased the assumed nuclear retention due to a carbon charge from **440 MW to 850 MW (to roughly one unit, 1/4 of Upstate capacity) in the Reference scenario**
- We have also expanded the 2030 uncertainty range to reflect a high cost case of no nuclear retention, and a low case of retaining all Upstate nukes
- NM2 is assumed to be online in both no carbon and carbon cases

Effects of Various Levels Nuclear Retention under 2030 Reference Assumptions

Scenario	Retention Due to Carbon Charges (MW)	Total Upstate Nuclear Capacity (MW)	Zone C Energy Price ($/MWh)	Nuclear Energy Margins ($/kW-year)	Effect of Nuclear Retention on CO_2 Emissions (million tons)	**Final Net Impact of Carbon Charge on Customer Costs (cents/kWh)**
Base Case, no carbon charge		1,292	$46.3	$266		
Additional nuclear retained by carbon charge						
No nuclear retention	0	1,292	$61.2	$373	0.00	**0.16**
Retain 1 unit	848	2,140	$56.2	$317	-1.06	**-0.19**
Retain 2 units	1,500	2,792	$52.3	$295	-1.87	**-0.47**
Retain all 3 at-risk units	2,054	3,346	$49.4	$279	-2.49	**-0.68**

Reference Assumptions

Repowering of Downstate Steam Units in 2025

- We evaluate the implications of additional Downstate steam unit repowering induced by a carbon charge
  - Analysis by the IMM suggests steam unit repowering may currently be economical
  - A carbon charge would increase Downstate CC revenues by $9/kW-yr, inducing more repowering than would otherwise occur
- Specifically, we estimate impacts of repowering two 60-year-old steam units (combined 850 MW) with two new 1x1 gas CCs of the same size in **2025**
  - Before repowering, steam runs at 20% capacity factor
  - Repowered CCs run at 70% capacity factor
- Repowering does not significantly change customer costs, but does lower NYCA CO_2 emissions and Downstate NOx emissions
  - **Customer costs** are unchanged (NYCA: +0.001, NYC: -0.002 c/kWh)
  - **NYCA CO_2 emissions** fall by 537,000 tons/yr, *in addition to* emission savings of 290,000 tons/yr under 2025 Reference assumptions (total reduction of 4% from base)
  - **NOx emissions** fall by 172 tons/yr in NYCA, mostly Downstate, *in addition to* emission savings of 470 tons/yr under 2025 Reference assumptions (total reduction of 6% from base)

Delayed Construction of Public Policy AC Transmission Project

Base case assumed increases in transfer limits across Central East and UPNY-SENY consistent with the AC Public Policy Transmission Need

- 350 MW enhancement of Central East in 2023
- 1,000 MW increase in UPNY-SENY in 2023
- **Central East**
  - Assumption is conservative since 350 MW is the *minimum* required for proposed projects to meet the public policy need and proposals evaluated generally exceed the minimum
  - If no AC transmission were built, Downstate LBMP effects would be slightly higher and Upstate LBMP effects would be slightly smaller
  - To the extent that AC transmission increases Central East limit above 350 MW, Downstate LBMP effects would be smaller and Upstate LBMP effects would be larger
- **UPNY-SENY**
  - Primarily a LHV capacity issue, not energy, as UPNY-SENY congestion limited in simulations

Agenda

Study Motivation, Scope, and Approach

Additional Analyses

Assessment of the Effects of Carbon Charges on Customer Costs (NYCA-wide)

- **Summary of 2022 Scenario**
- **Conclusions about customer costs**
- **Drivers and trends**

Analytical Details (including Zonal Effects)

Updated Customer Cost Impact Analysis

We have made two changes to the customer cost impact analysis presented at the October 15 IPPTF meeting

- **Higher expected 2030 Nuclear Retention:** per rationale discussed on Slides 16-18
- **High REC Claw-back Quantities:** previously assumed that all renewables *online* before 2020 would be subject to claw-back. Now assume all RECs *contracted* through 2018 are subject to claw-back (including units with online dates beyond 2020), and future NYSERDA procurements will be indexed to carbon price

	Prior Analysis	Current Analysis
Quantity of 2030 Nuclear Retention	Reference Assumption: 440 MW Nuclear Retirement Case: 280 MW	Reference Assumption: 850 MW Nuclear Retirement Case: 1200 MW
Quantity of Contracted RECs Subject to Claw-back Proposal	2025: 2.7 TWh 2030: 2.6 TWh	2022: 5.5 TWh 2025: 5.4 TWh 2030: 5.4 TWh

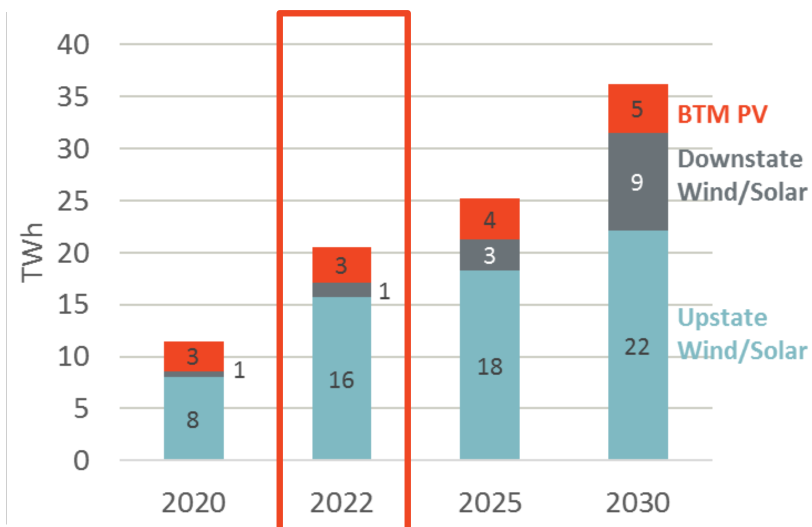
Sources and Notes: Current contracted quantities of RECs subject to claw-back calculated as 10.25 TWh of existing contracts, less 4.7 TWh in 2022, and 4.9 TWh in 2025 & 2030 of RECs coming off of contracts.

Summary of Modeled 2022 Scenario

- Representative of 1st year of carbon charge implementation
- Combination of IPEC retirement, twice as much renewables added Upstate, and no AC transmission upgrades → much more congested system than 2020
- Similar to 2020 case, assume minimal dynamic market adjustments
- See slides 43–45 for analytical details

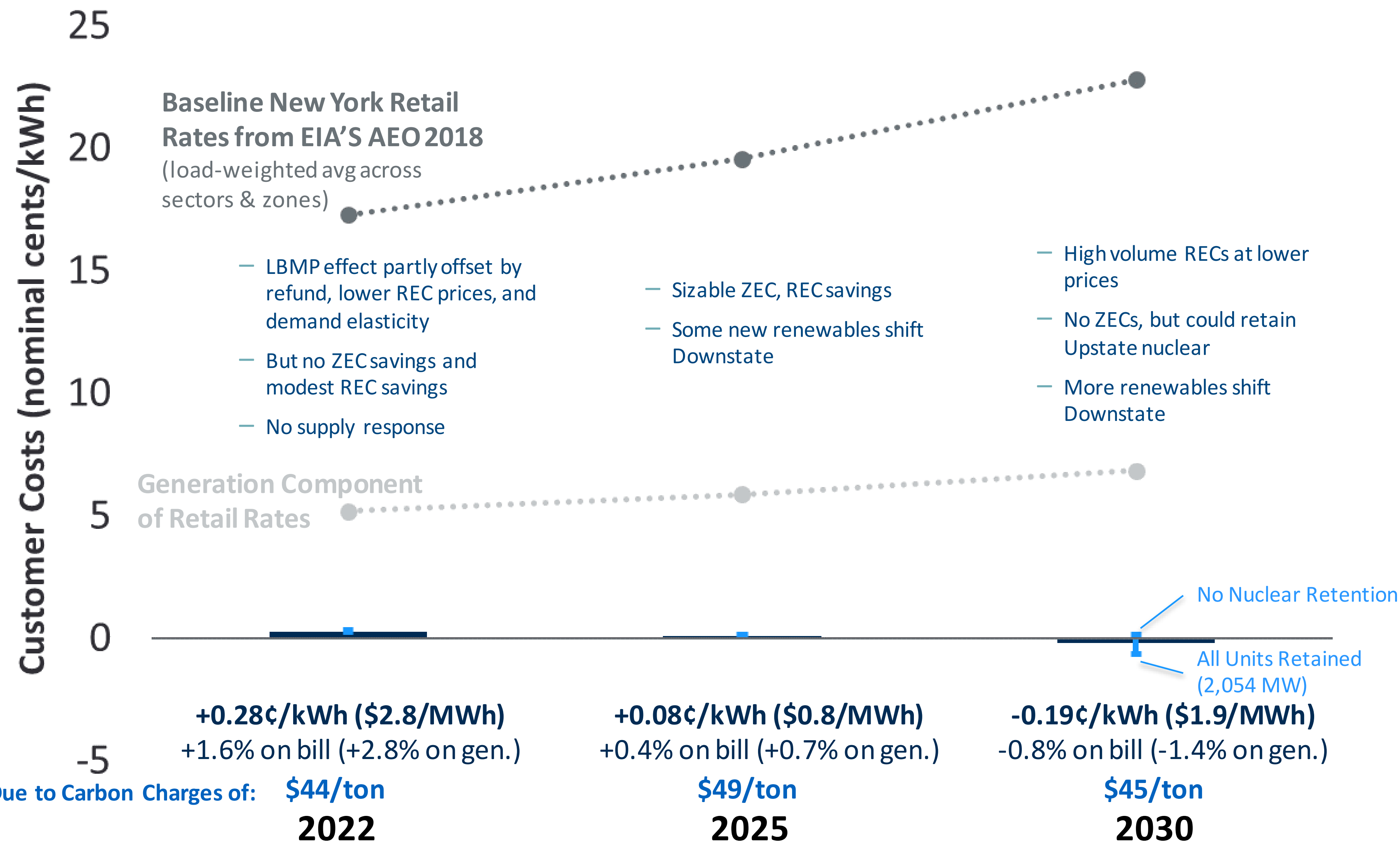
Year	Major Events	Event Category
Pre 2020	NYCA coal units retired; Selkirk, Binghamton, Greenport GT1 and Ravenswood 09 units retired	Thermal
2020	IP2 Retirement	Nuclear
2021	IP3 Retirement UPNY-ConEd Voltage Limit Increase	Nuclear, Transmission
2022	WNY Transmission In-Service NYSERDA Large Scale Renewables In-Service	Transmission Renewables
2023	AC Transmission In-Service, Athens SPS Out-of-Service	Transmission
2024	No Major Changes	
2025	No Major Changes	
2026-2028	No Major Changes	
2029	NMP1 and Ginna License Expiration, ZEC Expiration	Nuclear
2030	CES Target 50% (by 2030)	

Renewable Assumptions Across Scenarios



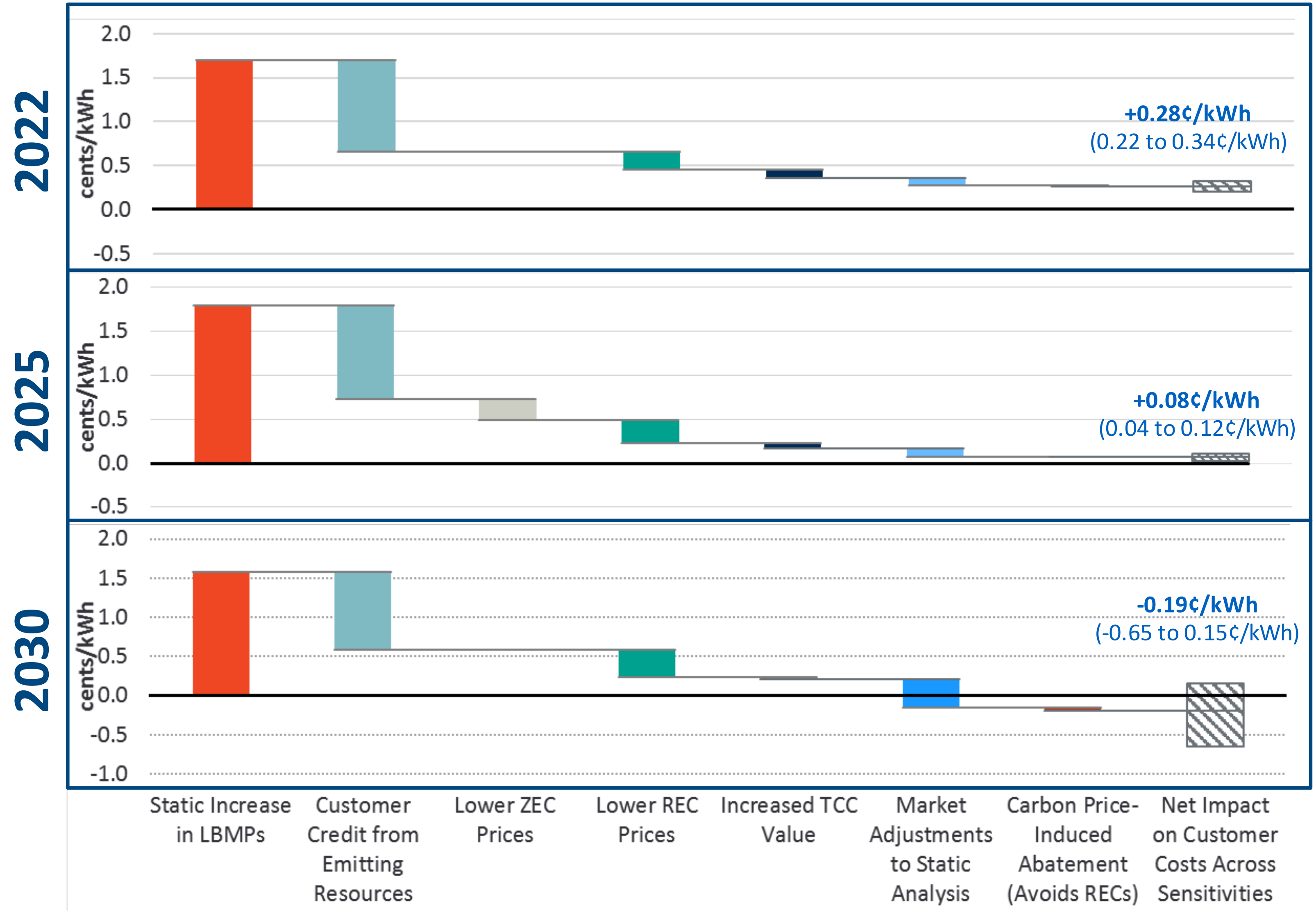
Note: Upstate defined as Zones A-E, Downstate as Zones F-K. Energy shown includes existing and new CES builds. Not shown: 0.5 – 0.8 TWh of existing biomass.

Effects on Customer Costs
compared to existing policies alone



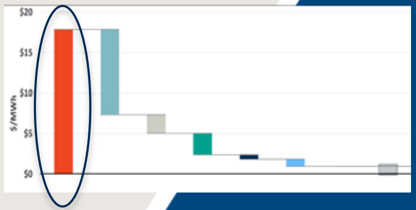
Note: 1 cent/kWh is equivalent to $10/MWh. Uncertainty bars reflect uncertainty across all dynamic effects, including nuclear retention, renewable shift, and load elasticity. Assumes that generation represents 30% of retail rate, based on IPPNY, "What's in Your Bill?", 2017.

Effects on Customer Costs



Note: 1 cent/kWh is equivalent to $10/MWh. Uncertainty bars reflect uncertainty across all dynamic effects, including nuclear retention, renewable shift, and load elasticity.

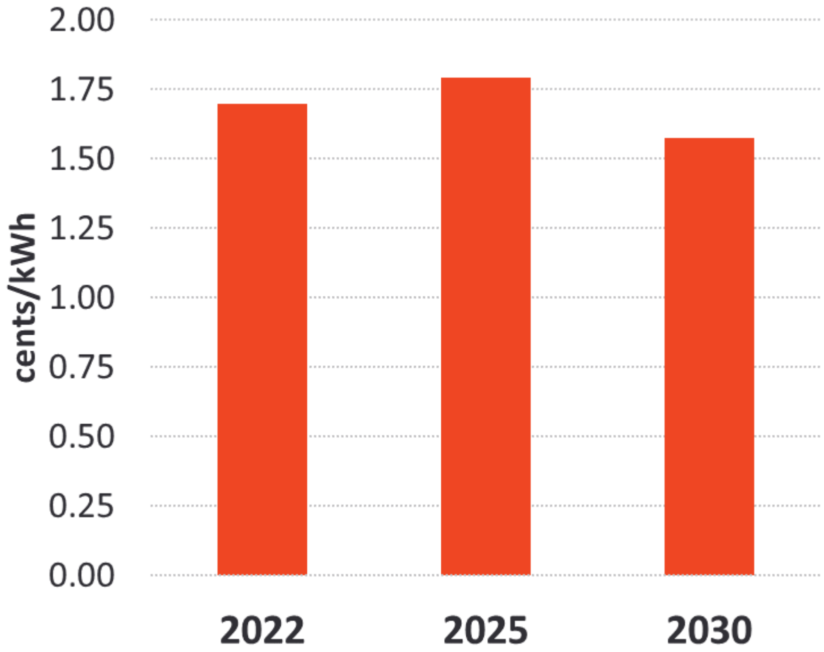
Effects on Wholesale Energy Prices



- LBMPs increase with carbon charges *times* marginal emission rates (MERs)
- MERs decline over time with greater renewable generation and declining load
  - 2022: 0.32 ton/MWh Upstate; 0.43 Downstate
  - 2025: 0.31 ton/MWh Upstate; 0.39 Downstate
  - 2030: 0.30 ton/MWh Upstate; 0.37 Downstate

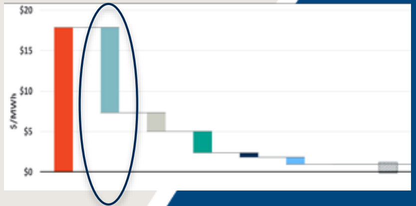
    (with Upstate defined as zones A-E)
- Carbon charges are fairly steady, with rising SCC offset by rising RGGI prices (per CARIS)*
  - 2022: $50 SCC – $7 RGGI = $44/ton
  - 2025: $57 SCC – $8 RGGI = $49/ton
  - 2030: $69 SCC – $24 RGGI = $45/ton
- Modest direct effect on commitment and dispatch due to limited fuel switching and locked imports (before dynamic effects)

Effects on Wholesale Energy Prices

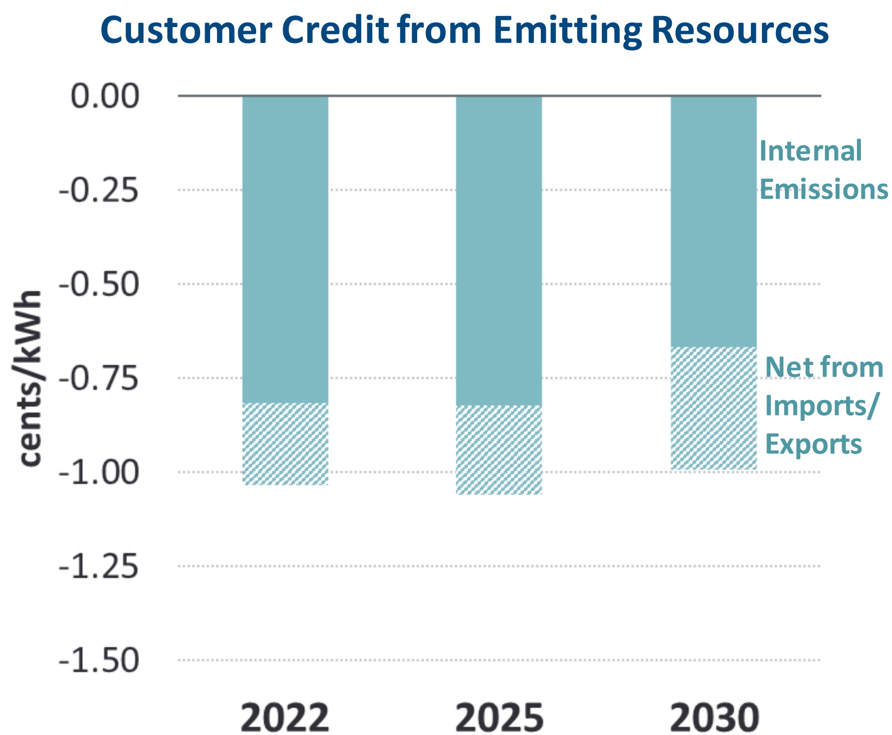


Note: * The RGGI prices assumed in our analysis are based on current CARIS assumptions. These are similar in 2022 and 2025 to those included in NYISO's Carbon Pricing Draft Recommendations report (projected by RGGI, Inc.) but much higher in 2030 ($24/ton versus $13/ton).

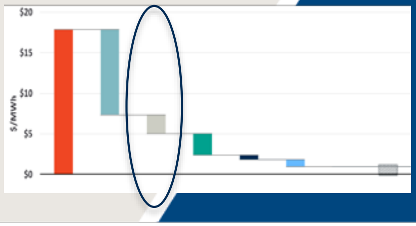
Customer Credits from Emitting Resources



- Customer credit reflects carbon charge *times* total emissions and adjustments to imports/exports
  - 2022: \$44/ton × 28 mil tons + \$335m
  - 2025: \$49/ton × 26 mil tons + \$358m
  - 2030: \$45/ton × 21 mil tons + \$469m
- Amounts trend similarly to changes in LBMPs, offsetting ~60% of wholesale price effect
  - Reflects total or average fleet emission rates, which are less than marginal rates, due to non-emitting generation
  - 2022 to 2025 increases slightly as rising carbon charge is partially offset by lower total emissions
  - Decrease by 2030 due to CES renewable additions and declining load
- Translates to bill savings by dividing total residuals among all 144-153 TWh of annual energy consumption *(<u>we express all savings categories this way</u>)*

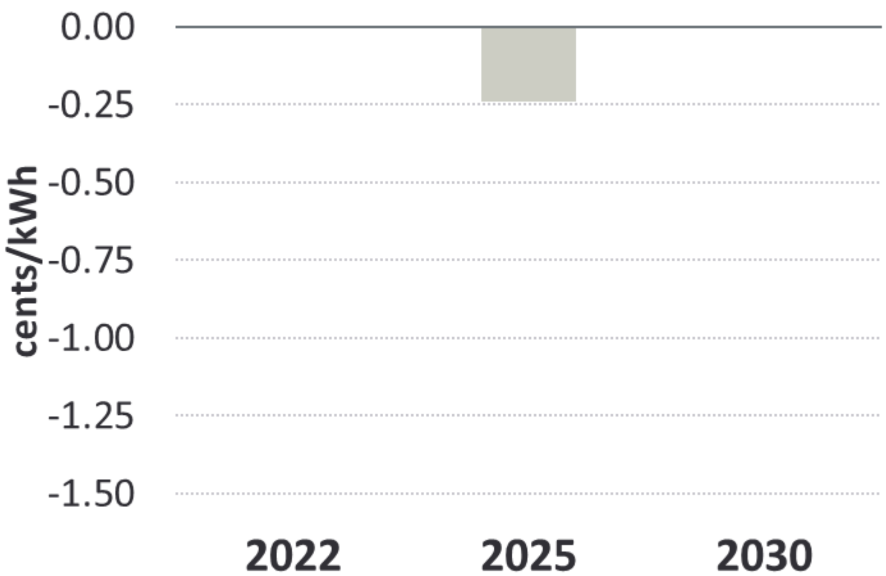


Lower ZEC Prices



- ZEC savings only occur in 2025
- 2022 prices (LBMP + capacity) are less than the $39/MWh threshold even with a carbon charge, so no indexing of ZEC prices to changes in LBMPs
- 2025 prices rise from $38/MWh to $52/MWh with carbon charge, reducing ZEC prices by $13/MWh
- ZEC program expires after 2029

Customer Benefit from Lower ZEC Prices

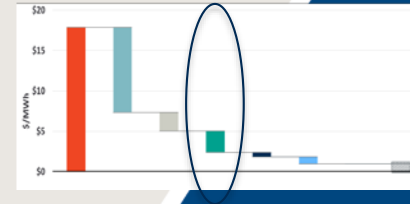


Clean Energy Standard ZEC Price Equation

Social Cost of Carbon - **Baseline RGGI Effect** - **Amount Zone A Forecast Energy Price and ROS Forecast Capacity Price combined exceeds $39/MWh** = **ZEC Price ($/MWh)**

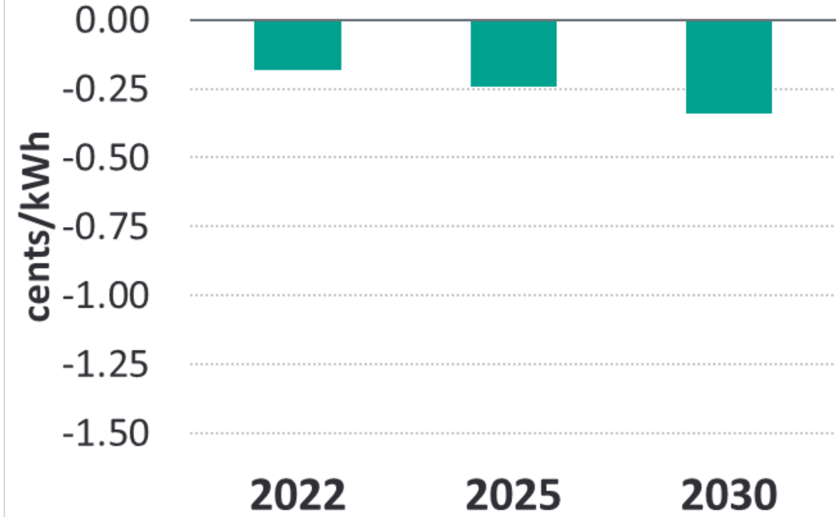
Note: Our estimated ZEC prices reflect NYPSC's SCC and modeled energy and capacity prices in that year, without regard to the adjacent year in each two-year tranche.

Lower REC Prices



- REC savings reflect REC purchases *times* the change in REC price due to carbon charge
- Carbon charges reduce REC prices from base case REC prices of $23-28/MWh
  - -$20/MWh in 2022, -$18 in 2025, -$16 in 2030
- Assume this adjustment applies in one form or another to all renewables except those whose REC contracts have expired

Customer Benefit from Lower REC Prices

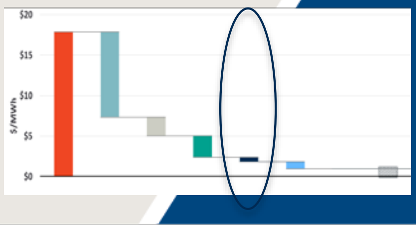


Effect of Carbon Charge on RECs

	2022			2025			2030		
	Quantity (TWh)	Increased energy revenues ($/MWh)	Customer savings ($/MWh)	Quantity (TWh)	Increased energy revenues ($/MWh)	Customer savings ($/MWh)	Quantity (TWh)	Increased energy revenues ($/MWh)	Customer savings ($/MWh)
RECs Contracted Through 2018	5.5	$12.3	$0.4	5.4	$13.7	$0.5	5.4	$12.3	$0.5
RECs Contracted After 2018	7.6	$19.6	$1.0	11.8	$18.3	$1.4	22.1	$15.8	$2.4
Distributed PV	3.5	$18.6	$0.4	4.0	$18.0	$0.5	4.6	$15.4	$0.5
Total	**16.6**	**$17.0**	**$1.8**	**21.2**	**$17.1**	**$2.4**	**32.1**	**$15.2**	**$3.4**

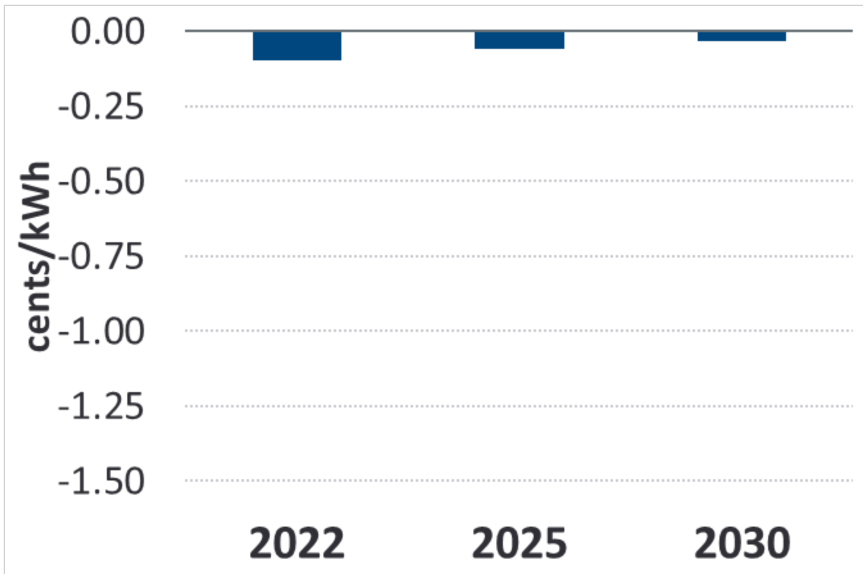
Sources and Notes: Contracted RECs through 2018 are net of contract expirations of 4.7 TWh in 2022 and 4.9 TWh in 2025 and 2030, based on *NYSERDA, New York State Renewable Portfolio Standard: Annual Performance Report Through December 31, 2016 Final Report, Appendix B, March 2017*.

Increased Value of TCCs



- Value of TCC contracts reflects change in NYISO congestion with carbon charge
- Base Case Congestion on Central East is steady at $290-$320 million, similar to historical congestion, due to several offsetting factors:
  - Growing Upstate renewable generation and declining load more than offset by loss of nuclear in Ontario and Upstate (reducing the difference in Market Heat Rate across Central East)
  - But rising gas prices increase the shadow price when Central East binds
- With carbon pricing applied to declining MER differential across CE, the effect of carbon pricing on Up-Down differentials and TCC values decreases over time
- Assume all congestion rents accrue to load

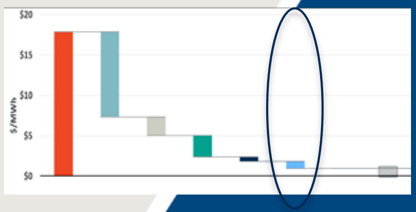
Customer Benefit from Increased TCC Value



Source: total congestion costs on all NY constraints in GE-MAPS runs

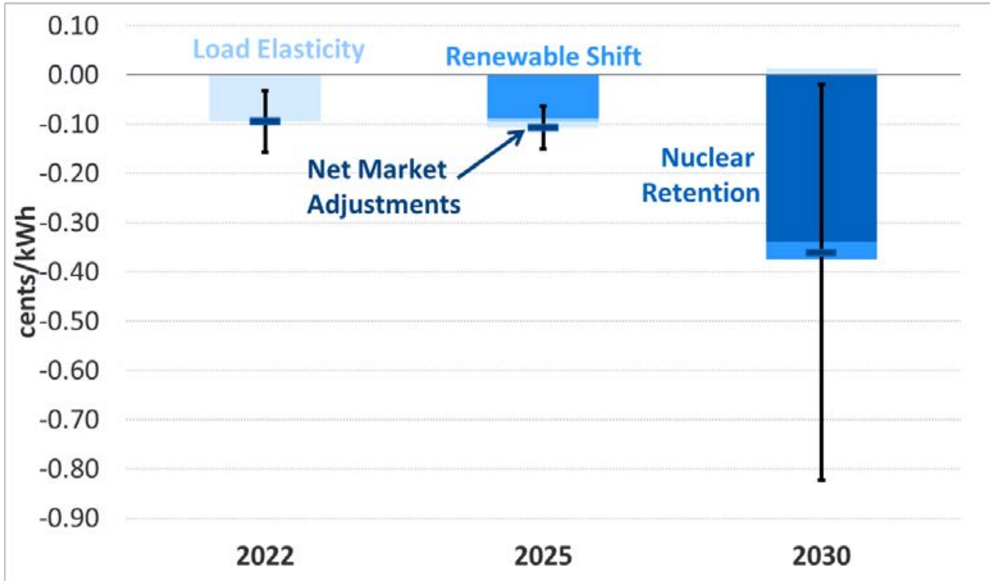
2022 has higher congestion ($450M on C/E in base) than other years due to IPEC retirement, twice as much renewables added Upstate, and no AC transmission upgrades.

Dynamic Market Adjustments



- In 2022, higher prices induce energy efficiency and conservation, reducing peak load by 230 MW and total demand by 1 TWh
- In 2025, assume 75% chance that 2.0 TWh of renewables (equiv. to ~1,400 MW PV) shift Downstate to re-equilibrate from increase in Downstate premium; 10% chance additional 640 MW PV enter
- In 2030, a carbon charge retains 850 MW Upstate nuclear (1/3 at-risk units); 75% chance 3.6 TWh of renewables (~2,500 MW PV) shift Downstate; 20% chance additional 580 MW PV enter

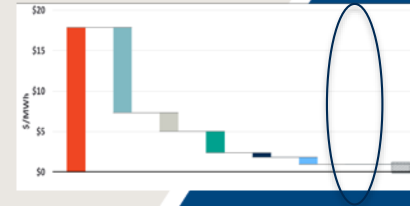
Customer Benefit from Dynamic Adjustments



Notes: Details are shown on slides 40-41.

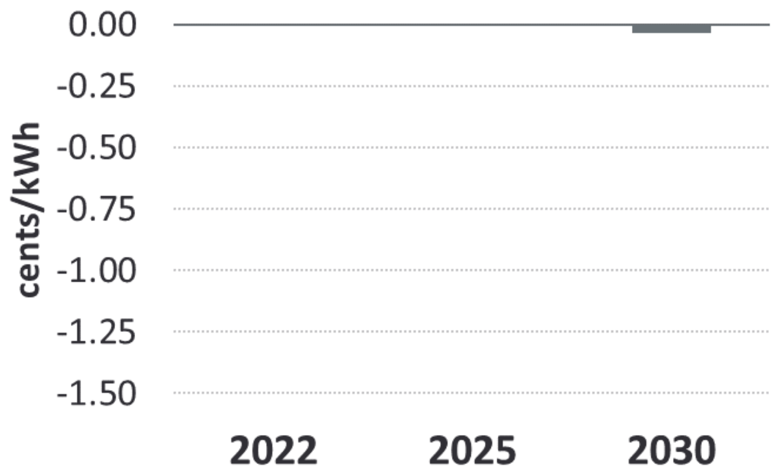
- To avoid overstating the effects, we analyze each sequentially given the expected value of prior effects (which diminishes the remaining price signal for subsequent adjustments).
- Estimates account for effects on not only energy and capacity prices, but also secondary reductions in customer credits from emitting resources and from REC, ZEC, and TCC effects.
- Error bars reflect a range of assumptions regarding induced changes to the supply mix such as nuclear retention, and demand elasticity, as shown on slide 41.
- Customer benefits from merchant PV entry are minimal due to offsetting reductions in REC savings.

New York Incremental Emissions Reductions or Avoided RECs

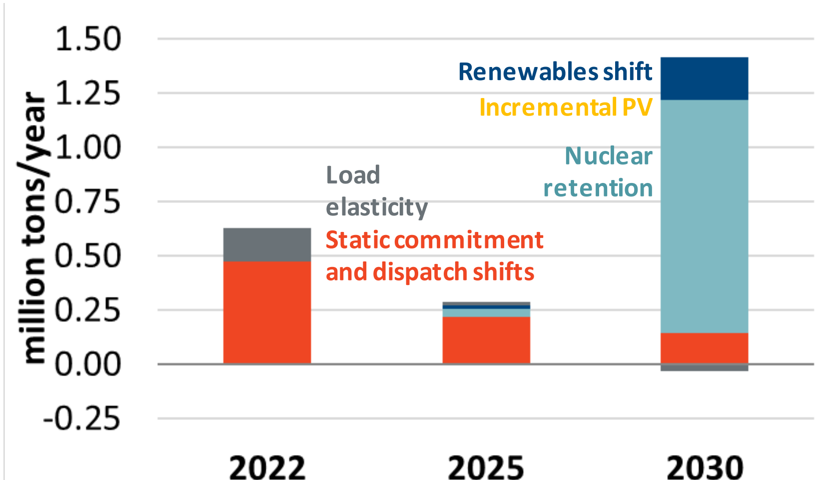


- Carbon charges lead to incremental internal emissions reductions of 6% by 2030 (-1.4 million tons from a baseline of 21 million tons internal emissions)
  - Limited fuel switching in MAPS runs due to addition of carbon charge
  - Most emission reductions from dynamic effects, including price-responsive load, renewable shifts, and possible nuclear retention
  - Reductions could be greater if the market finds innovative solutions we did not model (e.g., more low-cost renewables and storage, efficiency gains in the fossil fleet)
- Can translate avoided emissions into customer savings if they are going beyond CES to meet decarbonization goals, and now they can buy fewer RECs
- REC prices with carbon charges are $4/MWh in 2022, $7 in 2025, and $12 in 2030

Customer Benefit from Reduced RECs



Emissions Reductions from Carbon Charge



Note: Analysis only considers emission reductions associated with changes in New York load and generation. Load elasticity analysis assumes load-ratio share allocation of customer credits. We apply load elasticity across all NY load, including industrial.

Effect of a Carbon Charge on NOx Emissions

- A NYISO carbon charge would change dispatch and affect local NOx emissions
- RFF estimated that a carbon charge would reduce annual NY NOx emissions by 486 tons and annual SO_2 emissions by 5 tons in 2025
- Similar observations in the MAPS modeling:
  - Statewide annual NOx reductions of 370 to 470 tons/year, mostly Downstate
  - Adjusting for dynamic market adjustments, annual NOx reductions are 365 to 455 tons/year
  - Small changes in SO_2 emissions do not have a discernable pattern across years

Change in Annual NOx Emissions due to NYISO Carbon Charge

	2022 (tons)	**2025** (tons)	**2030** (tons)
Zone A	108	-23	-46
Zone B	44	14	-1
Zone C	84	9	-36
Zone D	-2	-1	-2
Zone E	1	2	-1
Zone F	26	-9	-16
Zone G	-131	-128	8
Zone H	0	0	-4
Zone I	0	0	0
Zone J	-534	-352	-285
Zone K	-52	17	17
NYCA	-455	-470	-365

Note: Results shown reflect MAPS outputs, adjusted to account for dynamic market adjustments.

Agenda

Study Motivation, Scope, and Approach

Additional Analyses

Assessment of the Effects of Carbon Charges on Customer Costs (NYCA-wide)

Analytical Details

- **Analytical approach**
- **Key inputs**
- **Snapshot of market prices before adding carbon charge**
- **Static and dynamic effects of a carbon charge**
- **Summary of costs and other metrics**
- **Impacts across zones**

Framework for Analysis

Difference shows the *static effect* of a carbon charge on dispatch, prices, and emissions

Base Case

From CARIS data, updated and extended

Static Carbon Charge Case

Add carbon charge of \$42 - \$49/ton (based on SCC and RGGI prices)

Dynamic Carbon Charge Case

Add assumed changes to fleet & load (based on offline analysis and MAPS results)

Difference shows the total effect of a carbon charge, including *dynamic effects*

Key Assumptions
(for Base Cases, before adding carbon charges)

Assumptions based primarily on CARIS, with a few differences to produce a "most likely" scenario

Year	New Renewable Resources	Nuclear Plants
2020 2022 2025	CARIS, mostly onshore renewables*	Indian Point retired in 2020/21
2030	1,300 MW off-shore wind	2,000 MW of Upstate nuclear retires by 2030*

Also analyzed alternative scenarios as discussed with IPPTF IT5

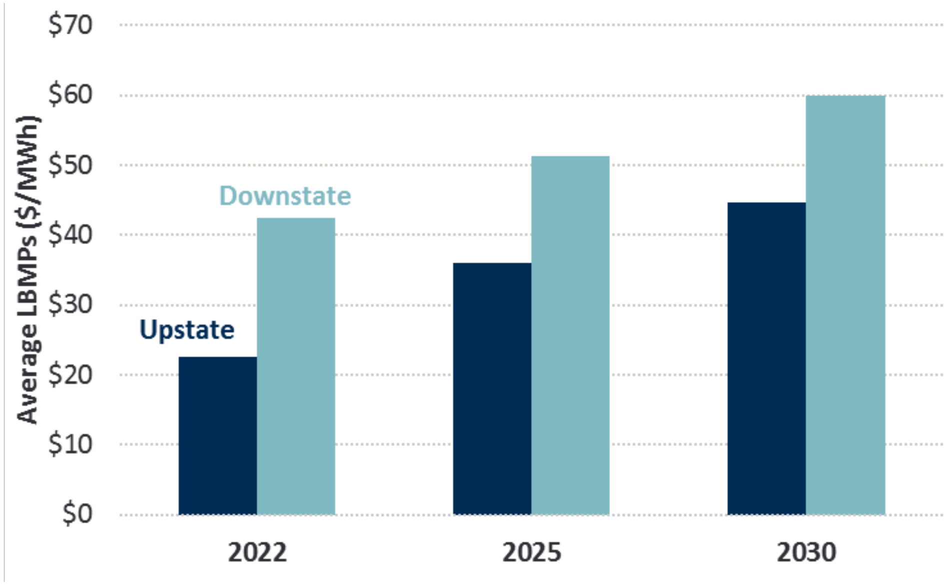
- **2025 with alternative low and high load**
- **2030 with alternative assumptions for offshore wind (OSW) and Upstate nuclear**
  - A. 250 MW OSW; all Upstate nuclear plants online ("CARIS-Based")
  - B. 2,400 MW OSW; all Upstate nuclear plants online ("High Wind")
  - C. 250 MW OSW; NMP2 & Fitz online; Ginna & NMP1 retired ("Nuclear Retirement")

* Previously, this slide stated 400 MW of offshore wind in 2025 and 2,700 MW of nuclear retirements by 2030, which was inconsistent with the modeling assumption.

Snapshot of Energy Market
(before adding carbon charges)

- Base case energy prices increase over time with rising gas prices
- Other factors are nuclear retirements, Ontario imports, and new renewables, and declining load, but these partially offset each other (see slide 44)

Average LBMPs by Region and Scenario ($/MWh)



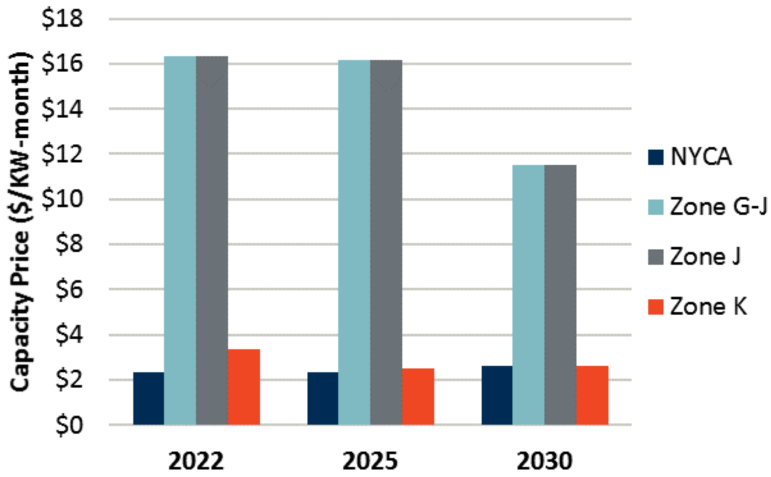
Source and Notes: Based on results from GE-MAPS runs. Prices are simple averages of hourly prices for each zone that are then weighted by load across Upstate (A-E) and Downstate (F-K) zones.

Snapshot of Capacity, RECs, and ZECs
(before adding carbon charges)

Capacity Prices

- NYCA prices remain low around $2/kW-mo
- Prices rise in G-J following Indian Point retirement (2020/2021), but remain lower than CC Net CONE
- Excludes capacity price effects of Downstate retirements due to pending DEC NOx rule

Capacity Price by Region and Year



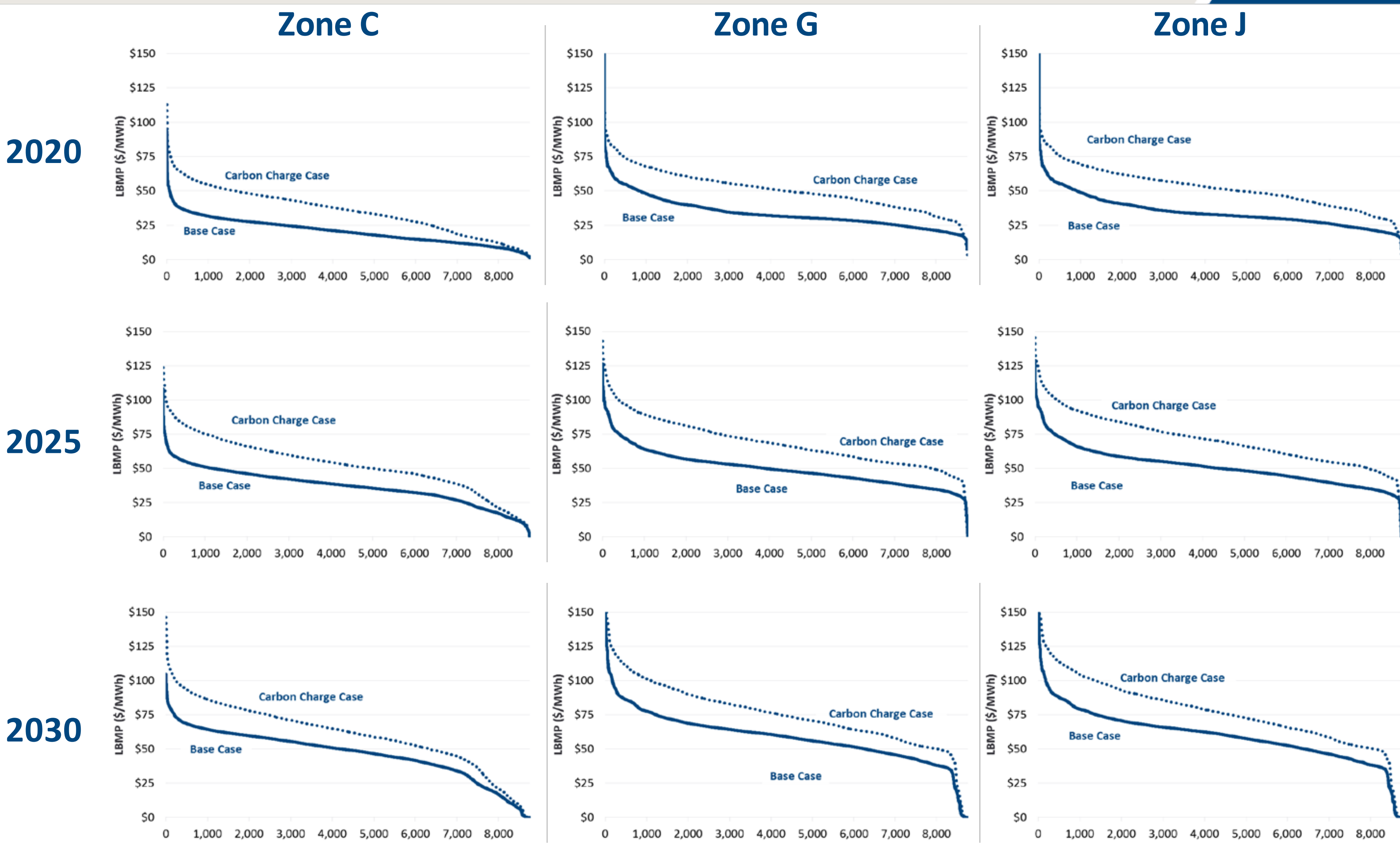
REC and ZEC Prices

- 2018-2020 REC prices are about $18-22/MWh
- NYSERDA assumes $24-25/MWh RECs in 2024;[1] we assume this value remains constant in real terms through 2030
- Projected ZEC prices of $22-25/MWh based on energy and capacity prices in Zone A
  - 2022: $22/MWh ZEC price, based on $21/MWh energy and $28/kW-yr capacity
  - 2025: $25/MWh ZEC price, based on $34/MWh energy and $28/kW-yr capacity
  - 2030: no ZEC program

Sources:
1. NYSERDA, Offshore Wind Policy Options Paper, Jan 29, 2018.

Static Price Effects of Carbon Charges

Price Duration Curves for Base Case and Carbon Charge Case



Dynamic Market Adjustments

We evaluated four changes in the resource mix and demand due to the carbon charge

Dynamic Effect	Concept	Analytical Approach
Nuclear Retention	Increased Upstate prices could retain nuclear plant in 2030	• Value quantified as difference in customer costs in MAPS runs with and without nuclear units • Assume 1 out of 3 at-risk units are retained due to carbon charge
Shift Renewables Downstate	Increased Downstate energy price premium causes some new renewables to shift from Upstate	• Observe how much a carbon charge plus the expected effect of nuclear retention increases the Downstate energy price premium • Shift sufficient capacity to erode the increase using MAPS to inform the changes in LBMPs from shifting capacity • Assume 75% likelihood of investment shift in 2025 and 2030
Incremental Solar Investment	If solar becomes so economic that REC prices fall to/near zero, a carbon charge could induce investment of solar beyond the amount mandated by the CES	• Observe how much a carbon charge plus the expected effects of the nuclear retention and renewable shift increase solar revenues in Zone G • Assume some of the increased solar revenues reduce REC prices to zero and then provide an extra profit of $5/MWh • Add enough incremental PV to erase that gain using MAPS to inform the changes in LBMPs from adding incremental solar capacity in Zone G • Assume 10% chance in 2025 and 20% in 2030 of PV being sufficiently economic w/o RECs • Results in a reduction in REC price savings
Load Elasticity	Customers adjust consumption due to higher/lower rates with a carbon charge	• Observe the change in customer costs, net of expected dynamics; assume all costs/credits apply to all customers on a per-kWh basis • Assume customers' average elasticity of demand is -0.3 • Estimate reduction in LBMPs based on 2025 high/low load MAPS runs

Dynamic Effects (cont.)

Dynamic Effect	Year	Change due to Carbon Charge and prior Dynamic Effects	Market Adjustment (Change in Capacity/Load)	Uncertainty Range
Nuclear Retention	2030	Nuclear Revenues +$107/kW-year	Retain 850 MW of Upstate nuclear	Retain 0 to 2000 MW
Shift Renewables Downstate	2025	Downstate Premium +$4/MWh	75% likelihood of shifting 2.0 TWh Downstate (*1.5 TWh expected value*)	50 to 100% likelihood
	2030	Downstate Premium +$9/MWh	75% likelihood of shifting 3.6 TWh Downstate (*2.7 TWh expected value*)	
Incremental Solar Investment	2025	Zone G Solar Revenues +$18/MWh	10% likelihood of an incremental 640 MW of PV (*64 MW expected value*)	0 to 2x
	2030	Zone G Solar Revenues +$16/MWh	20% likelihood of an incremental 580 MW of PV (*116 MW expected value*)	
Load Elasticity	2022	Customer Costs (range across zones) -0.02 to +0.54 ¢/kWh	-0.3 elasticity lowers system peak 237 MW, energy 1,028 GWh	-0.1 to -0.5 elasticity of demand
	2025	Customer Costs (range across zones) -0.06 to +0.32 ¢/kWh	-0.3 elasticity lowers system peak 58 MW, energy 240 GWh	
	2030	Customer Costs (range across zones) -0.42 to +0.16 ¢/kWh	-0.3 elasticity *raises* system peak 80 MW, energy 400 GWh	

Dynamic Effects (cont.)

Other dynamic effects are possible but not quantified here:

- Innovations that market prices may stimulate but we cannot anticipate
- Increased investment in efficient new CCs vs. existing/new CTs
  - Our analysis indicates that carbon charges provide only a small increase in CC net revenues, but that could depend on location-specific gas prices and market heat rates
  - Investment more likely in combination with pending NOx rule
- Increased investment in and utilization of energy storage
- Efficiency improvements in the existing fleet

Summary of Customer Cost Effects

	2020	2022	2025	2030
STATIC ANALYSIS (cents/kWh of load)				
I. Increase in Wholesale Energy Prices	**1.64**	**1.70**	**1.79**	**1.58**
II. Customer Credit from Emitting Resources	**(0.99)**	**(1.04)**	**(1.06)**	**(0.99)**
III. Lower ZEC Prices	**0.00**	**0.00**	**(0.24)**	**0.00**
IV. Lower REC Prices	**(0.08)**	**(0.18)**	**(0.24)**	**(0.34)**
V. Increased TCC Value	**(0.06)**	**(0.10)**	**(0.06)**	**(0.03)**
Subtotal	**0.51**	**0.38**	**0.19**	**0.21**
DYNAMIC ADJUSTMENTS (cents/kWh of load)				
VI. Market Adjustments to Static Analysis	**(0.12)**	**(0.09)**	**(0.11)**	**(0.36)**
A. Nuclear Retention	**0.00**	**0.00**	**0.00**	**(0.34)**
Retained Nuclear (MW)	*0*	*0*	*0*	*852*
Assumed Likelihood	*0%*	*0%*	*0%*	*100%*
B. Renewable Shift Downstate	**0.00**	**0.00**	**(0.09)**	**(0.03)**
RE Shift Downstate (TWh)	*0.0*	*0.0*	*2.0*	*3.6*
Assumed Likelihood	*0%*	*0%*	*75%*	*75%*
C. Incremental Renewable Entry	**0.00**	**0.00**	**(0.01)**	**(0.00)**
Incremental PV Entry (MW)	*0*	*0*	*638*	*579*
Assumed Likelihood	*0%*	*0%*	*10%*	*20%*
D. Load Elasticity	**(0.12)**	**(0.09)**	**(0.01)**	**0.01**
Peak Load Reduction (Increase) (MW)	*333*	*237*	*58*	*(78)*
Annual Load Reduction (Increase) (GWh)	*1,513*	*1,028*	*240*	*(395)*
Assumed Likelihood	*100%*	*100%*	*100%*	*100%*
VII. Carbon Price-Induced Abatement (Avoided RECs)	**(0.00)**	**(0.00)**	**(0.00)**	**(0.04)**
CO_2 Abatement (million tons)	*0.8*	*0.6*	*0.3*	*1.4*
Avoided RECs beyond CES (TWh)	*2.3*	*1.9*	*0.9*	*4.2*
Subtotal	**(0.12)**	**(0.10)**	**(0.11)**	**(0.40)**
TOTAL EFFECT (cents/kWh of load)				
Net Change in Customer Costs	**0.39**	**0.28**	**0.08**	**(0.19)**
Range Accounting for Uncertainty in Dynamic Effects	**0.31 to 0.47**	**0.22 to 0.34**	**0.04 to 0.12**	**-0.65 to 0.15**

Summary of Key Metrics

	2020	2022	2025	2030
KEY ASSUMPTIONS & OUTPUTS				
SCC ($/ton)	$47	$50	$57	$69
RGGI Price ($/ton)	$6	$7	$8	$24
Carbon Charge ($/ton), >25MW	$42	$44	$49	$45
NYCA Load (TWh)	156.1	153.3	150.1	143.9
Upstate Nuclear (TWh)	26.1	25.9	27.4	9.7
Downstate Nuclear (TWh)	10.9	0.0	0.0	0.0
Total Renewables (TWh)	12.1	21.3	26.1	37.0
Upstate Wind/Solar (TWh)	8.0	15.7	18.3	22.1
Downstate Wind/Solar (TWh)	0.6	1.4	2.9	9.4
Contracted RECs Subject to Clawback (TWh)	7.5	5.5	5.4	5.4
Distributed PV with Offsets to Carbon LBMP (TWh)	2.8	3.5	4.0	4.6
Renewables Added After 2020 with Indexed REC (TWh)	1.8	10.7	14.5	24.8
Net Imports (TWh)	24.6	21.9	19.7	29.5
Upstate LBMP, base case ($/MWh)	$20	$23	$36	$45
Downstate LBMP, base case ($/MWh)	$35	$42	$51	$60
Upstate LBMP, simple change case ($/MWh)	$35	$36	$51	$58
Downstate LBMP, simple change case ($/MWh)	$52	$61	$71	$77
Central East Congestion, base ($ million)	$289	$451	$314	$317
Central East Congestion, simple change ($ million)	$344	$564	$364	$343
ZEC price, before carbon charge ($/MWh)	$20	$22	$25	$0
ZEC price, after carbon charge ($/MWh)	$20	$22	$12	$0
REC price, before carbon charge ($/MWh)	$22	$23	$25	$28
REC price, after carbon charge ($/MWh)	$3	$4	$7	$12
NYCA CO2 Emissions, base case (million tons)	29.1	29.2	25.5	21.4
NYCA CO2 Emissions, simple change case (million tons)	28.5	28.8	25.3	21.2

Note: NYCA CO2 emissions do not account for emissions associated with net imports that are "locked-in" in the base case without a carbon charge. Dollars are expressed in nominal terms. Generation shown from simple change case.

Analysis of Alternative Scenarios

	2020	2022	2025				2030			
	CARIS-Based	CARIS-Based	Reference	CARIS-Based	Low Load	High Load	Reference	CARIS-Based	High Wind	Nuclear Retention
STATIC ANALYSIS (cents/kWh of load)										
I. Increase in Wholesale Energy Prices	1.64	1.70	1.79	1.79	1.76	1.81	1.58	1.36	1.34	1.50
II. Customer Credit from Emitting Resources	(0.99)	(1.04)	(1.06)	(1.06)	(1.04)	(1.07)	(0.99)	(0.80)	(0.76)	(0.91)
III. Lower ZEC Prices	0.00	0.00	(0.24)	(0.23)	(0.25)	(0.25)	0.00	0.00	0.00	0.00
IV. Lower REC Prices	(0.08)	(0.18)	(0.24)	(0.24)	(0.21)	(0.28)	(0.34)	(0.26)	(0.31)	(0.31)
V. Increased TCC Value	(0.06)	(0.10)	(0.06)	(0.05)	(0.06)	(0.07)	(0.03)	(0.19)	(0.14)	(0.12)
Subtotal	0.51	0.38	0.19	0.21	0.21	0.14	0.21	0.12	0.13	0.16
DYNAMIC ADJUSTMENTS (cents/kWh of load)										
VI. Market Adjustments to Static Analysis	(0.12)	(0.09)	(0.11)	(0.08)	(0.08)	(0.08)	(0.36)	(0.17)	(0.11)	(0.83)
A. Nuclear Retention	0.00	0.00	0.00	0.00	0.00	0.00	(0.34)	0.00	0.00	(0.58)
Retained Nuclear (MW)	*0*	*0*	*0*	*0*	*0*	*0*	*852*	*0*	*0*	*1,206*
Assumed Likelihood	*0%*	*0%*	*0%*	*0%*	*0%*	*0%*	*100%*	*0%*	*0%*	*100%*
B. Renewable Shift Downstate	0.00	0.00	(0.09)	(0.06)	(0.05)	(0.06)	(0.03)	(0.17)	(0.10)	(0.32)
RE Shift Downstate (TWh)	*0.0*	*0.0*	*2.0*	*1.4*	*1.3*	*1.7*	*3.6*	*3.5*	*2.0*	*6.9*
Assumed Likelihood	*0%*	*0%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*	*75%*
C. Incremental Renewable Entry	0.00	0.00	(0.01)	(0.01)	(0.01)	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)
Incremental PV Entry (MW)	*0*	*0*	*638*	*638*	*608*	*674*	*579*	*358*	*311*	*358*
Assumed Likelihood	*0%*	*0%*	*10%*	*10%*	*10%*	*10%*	*20%*	*20%*	*20%*	*20%*
D. Load Elasticity	(0.12)	(0.09)	(0.01)	(0.02)	(0.02)	(0.01)	0.01	0.00	(0.01)	0.08
Peak Load Reduction (Increase) (MW)	*333*	*237*	*58*	*83*	*81*	*43*	*(78)*	*(20)*	*15*	*(342)*
Annual Load Reduction (Increase) (GWh)	*1,513*	*1,028*	*240*	*358*	*347*	*176*	*(395)*	*(108)*	*45*	*(1,587)*
Assumed Likelihood	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*	*100%*
VII. Carbon Price-Induced Abatement (Avoided RECs)	(0.00)	(0.00)	(0.00)	(0.01)	(0.01)	(0.01)	(0.04)	(0.03)	(0.02)	(0.06)
CO_2 Abatement (million tons)	*0.8*	*0.6*	*0.3*	*0.5*	*0.5*	*0.5*	*1.4*	*0.6*	*0.4*	*1.7*
Avoided RECs beyond CES (TWh)	*2.3*	*1.9*	*0.9*	*1.4*	*1.4*	*1.4*	*4.2*	*2.7*	*1.6*	*6.3*
Subtotal	(0.12)	(0.10)	(0.11)	(0.08)	(0.09)	(0.08)	(0.40)	(0.20)	(0.13)	(0.89)
TOTAL EFFECT (cents/kWh of load)										
Net Change in Customer Costs	0.39	0.28	0.08	0.12	0.12	0.05	(0.19)	(0.08)	0.01	(0.73)
Range Accounting for Uncertainty in Dynamic Effects	0.31 to 0.47	0.22 to 0.34	0.04 to 0.12	0.08 - 0.16	0.08 to 0.16	0.02 to 0.09	-0.65 to 0.15	-0.14 to -0.02	-0.04 to 0.05	-1.18 to -0.09

Notes: CARIS-Based scenarios refer to the Scenario A results presented in previous IPPTF slides.
Additional scenario descriptions provided on slide 30; dynamic effects explained on slides 32 and 40-41.
Costs are expressed in nominal terms.

Zonal Details, 2022 Reference

Customer Cost Impact of a $44/ton Carbon Charge, 2022
(cents/kWh)

	NYCA Average	Zone A	Zone B	Zone C	Zone D	Zone E	Zone F	Zone G	Zone H	Zone I	Zone J	Zone K
STATIC ANALYSIS												
I. Static Increase in LBMPs	1.697	1.363	1.370	1.420	1.312	1.422	1.868	1.824	1.840	1.844	1.868	1.875
II. Customer Credit from Emitting Resources - (A) Load-Ratio Allocation	-1.035	-1.035	-1.035	-1.035	-1.035	-1.035	-1.035	-1.035	-1.035	-1.035	-1.035	-1.035
II. Customer Credit from Emitting Resources - (B) Proportional % Levelization	-1.035	-0.980	-0.964	-0.984	-0.889	-0.948	-1.075	-1.058	-1.065	-1.066	-1.084	-1.056
II. Customer Credit from Emitting Resources - (C) Proportional Allocation	-1.035	-0.831	-0.836	-0.867	-0.800	-0.867	-1.140	-1.113	-1.123	-1.125	-1.139	-1.144
II. Customer Credit from Emitting Resources - (D) Levelizing Allocation	-1.035	-0.701	-0.708	-0.759	-0.650	-0.760	-1.206	-1.162	-1.179	-1.182	-1.206	-1.213
III. Lower ZEC Prices	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
IV. Lower REC Prices	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184	-0.184
V. Increased TCC Value	-0.098	-0.098	-0.098	-0.098	-0.098	-0.098	-0.098	-0.098	-0.098	-0.098	-0.098	-0.098
Subtotal (A)	**0.380**	**0.046**	**0.053**	**0.104**	**-0.005**	**0.105**	**0.551**	**0.507**	**0.524**	**0.527**	**0.551**	**0.558**
Subtotal (B)	**0.380**	**0.101**	**0.125**	**0.155**	**0.142**	**0.192**	**0.512**	**0.485**	**0.494**	**0.496**	**0.502**	**0.537**
Subtotal (C)	**0.380**	**0.250**	**0.253**	**0.272**	**0.230**	**0.273**	**0.447**	**0.430**	**0.436**	**0.437**	**0.447**	**0.450**
Subtotal (D)	**0.380**	**0.380**	**0.380**	**0.380**	**0.380**	**0.380**	**0.380**	**0.380**	**0.380**	**0.380**	**0.380**	**0.380**
DYNAMIC ANALYSIS												
VI. Market Adjustments to Static Analysis - (A)	-0.094	-0.015	-0.015	-0.014	-0.016	-0.015	-0.035	-0.060	-0.067	-0.070	-0.186	-0.187
VI. Market Adjustments to Static Analysis - (B)	-0.092	-0.019	-0.019	-0.018	-0.011	-0.018	-0.038	-0.061	-0.067	-0.070	-0.171	-0.182
VI. Market Adjustments to Static Analysis - (C)	-0.089	-0.025	-0.025	-0.024	-0.013	-0.026	-0.045	-0.062	-0.067	-0.070	-0.155	-0.157
VI. Market Adjustments to Static Analysis - (D)	-0.085	-0.032	-0.032	-0.031	-0.011	-0.033	-0.051	-0.063	-0.067	-0.069	-0.135	-0.138
VII. Carbon Price-Induced Abatement (Avoided RECs)	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004
Total Net Change in Customer Costs (A)	**0.282**	**0.026**	**0.034**	**0.085**	**-0.026**	**0.086**	**0.512**	**0.442**	**0.452**	**0.453**	**0.361**	**0.367**
Total Net Change in Customer Costs (B)	**0.284**	**0.077**	**0.102**	**0.133**	**0.126**	**0.169**	**0.469**	**0.419**	**0.422**	**0.421**	**0.327**	**0.351**
Total Net Change in Customer Costs (C)	**0.287**	**0.220**	**0.223**	**0.244**	**0.213**	**0.242**	**0.398**	**0.363**	**0.365**	**0.363**	**0.288**	**0.288**
Total Net Change in Customer Costs (D)	**0.290**	**0.344**	**0.344**	**0.345**	**0.365**	**0.342**	**0.325**	**0.313**	**0.308**	**0.306**	**0.241**	**0.238**

Zonal Details, 2025 Reference

Customer Cost Impact of a $49/ton Carbon Charge, 2025 (cents/kWh)

	NYCA Average	Zone A	Zone B	Zone C	Zone D	Zone E	Zone F	Zone G	Zone H	Zone I	Zone J	Zone K
STATIC ANALYSIS												
I. Static Increase in LBMPs	1.794	1.477	1.515	1.562	1.521	1.591	1.836	1.876	1.896	1.901	1.958	1.961
II. Customer Credit from Emitting Resources - (A) Load-Ratio Allocation	-1.061	-1.061	-1.061	-1.061	-1.061	-1.061	-1.061	-1.061	-1.061	-1.061	-1.061	-1.061
II. Customer Credit from Emitting Resources - (B) Proportional % Levelization	-1.061	-0.947	-0.964	-0.986	-0.959	-1.000	-1.037	-1.074	-1.086	-1.090	-1.136	-1.102
II. Customer Credit from Emitting Resources - (C) Proportional Allocation	-1.061	-0.886	-0.908	-0.935	-0.910	-0.958	-1.076	-1.099	-1.113	-1.116	-1.152	-1.155
II. Customer Credit from Emitting Resources - (D) Levelizing Allocation	-1.061	-0.766	-0.803	-0.848	-0.807	-0.888	-1.086	-1.125	-1.149	-1.154	-1.215	-1.220
III. Lower ZEC Prices	-0.243	-0.243	-0.243	-0.243	-0.243	-0.243	-0.243	-0.243	-0.243	-0.243	-0.243	-0.243
IV. Lower REC Prices	-0.241	-0.241	-0.241	-0.241	-0.241	-0.241	-0.241	-0.241	-0.241	-0.241	-0.241	-0.241
V. Increased TCC Value	-0.058	-0.058	-0.058	-0.058	-0.058	-0.058	-0.058	-0.058	-0.058	-0.058	-0.058	-0.058
Subtotal (A)	**0.191**	**-0.125**	**-0.087**	**-0.040**	**-0.081**	**-0.011**	**0.234**	**0.274**	**0.293**	**0.299**	**0.356**	**0.358**
Subtotal (B)	**0.191**	**-0.011**	**0.010**	**0.034**	**0.020**	**0.049**	**0.258**	**0.260**	**0.268**	**0.270**	**0.281**	**0.317**
Subtotal (C)	**0.191**	**0.050**	**0.066**	**0.086**	**0.069**	**0.091**	**0.219**	**0.235**	**0.241**	**0.243**	**0.264**	**0.263**
Subtotal (D)	**0.191**	**0.169**	**0.171**	**0.172**	**0.172**	**0.162**	**0.209**	**0.209**	**0.205**	**0.205**	**0.202**	**0.198**
DYNAMIC ANALYSIS												
VI. Market Adjustments to Static Analysis - (A)	-0.107	0.074	0.070	0.066	0.067	0.103	-0.068	-0.279	-0.265	-0.265	-0.258	-0.078
VI. Market Adjustments to Static Analysis - (B)	-0.105	0.071	0.066	0.063	0.066	0.099	-0.072	-0.281	-0.266	-0.266	-0.247	-0.073
VI. Market Adjustments to Static Analysis - (C)	-0.104	0.070	0.065	0.062	0.066	0.098	-0.073	-0.281	-0.266	-0.266	-0.245	-0.066
VI. Market Adjustments to Static Analysis - (D)	-0.103	0.067	0.062	0.059	0.066	0.094	-0.077	-0.282	-0.267	-0.267	-0.236	-0.057
VII. Carbon Price-Induced Abatement (Avoided RECs)	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004	-0.004
Total Net Change in Customer Costs (A)	**0.081**	**-0.055**	**-0.021**	**0.022**	**-0.018**	**0.087**	**0.162**	**-0.010**	**0.025**	**0.030**	**0.094**	**0.276**
Total Net Change in Customer Costs (B)	**0.082**	**0.056**	**0.072**	**0.094**	**0.082**	**0.144**	**0.182**	**-0.025**	**-0.003**	**-0.001**	**0.029**	**0.240**
Total Net Change in Customer Costs (C)	**0.083**	**0.115**	**0.127**	**0.144**	**0.131**	**0.185**	**0.142**	**-0.050**	**-0.029**	**-0.027**	**0.015**	**0.194**
Total Net Change in Customer Costs (D)	**0.085**	**0.232**	**0.229**	**0.227**	**0.233**	**0.252**	**0.128**	**-0.077**	**-0.066**	**-0.066**	**-0.039**	**0.137**

Zonal Details, 2030 Reference

Customer Cost Impact of a $45/ton Carbon Charge, 2030
(cents/kWh)

	NYCA Average	Zone A	Zone B	Zone C	Zone D	Zone E	Zone F	Zone G	Zone H	Zone I	Zone J	Zone K
STATIC ANALYSIS												
I. Static Increase in LBMPs	1.575	1.301	1.379	1.412	1.359	1.418	1.608	1.641	1.660	1.665	1.709	1.677
II. Customer Credit from Emitting Resources - (A) Load-Ratio Allocation	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995
II. Customer Credit from Emitting Resources - (B) Proportional % Levelization	-0.995	-0.827	-0.873	-0.889	-0.863	-0.899	-0.989	-1.023	-1.040	-1.044	-1.091	-1.047
II. Customer Credit from Emitting Resources - (C) Proportional Allocation	-0.995	-0.801	-0.845	-0.864	-0.831	-0.872	-1.023	-1.036	-1.053	-1.056	-1.094	-1.077
II. Customer Credit from Emitting Resources - (D) Levelizing Allocation	-0.995	-0.701	-0.767	-0.795	-0.745	-0.809	-1.038	-1.058	-1.084	-1.089	-1.146	-1.120
III. Lower ZEC Prices	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
IV. Lower REC Prices	-0.340	-0.340	-0.340	-0.340	-0.340	-0.340	-0.340	-0.340	-0.340	-0.340	-0.340	-0.340
V. Increased TCC Value	-0.033	-0.033	-0.033	-0.033	-0.033	-0.033	-0.033	-0.033	-0.033	-0.033	-0.033	-0.033
Subtotal (A)	**0.208**	**-0.067**	**0.012**	**0.045**	**-0.008**	**0.051**	**0.241**	**0.274**	**0.293**	**0.297**	**0.342**	**0.309**
Subtotal (B)	**0.208**	**0.101**	**0.134**	**0.150**	**0.123**	**0.147**	**0.246**	**0.245**	**0.247**	**0.247**	**0.245**	**0.257**
Subtotal (C)	**0.208**	**0.127**	**0.162**	**0.176**	**0.155**	**0.173**	**0.212**	**0.232**	**0.234**	**0.235**	**0.242**	**0.227**
Subtotal (D)	**0.208**	**0.227**	**0.240**	**0.244**	**0.241**	**0.237**	**0.197**	**0.210**	**0.203**	**0.203**	**0.190**	**0.184**
DYNAMIC ANALYSIS												
VI. Market Adjustments to Static Analysis - (A)	-0.361	-0.342	-0.395	-0.415	-0.404	-0.382	-0.234	-0.524	-0.491	-0.489	-0.394	-0.168
VI. Market Adjustments to Static Analysis - (B)	-0.359	-0.346	-0.400	-0.420	-0.406	-0.387	-0.239	-0.526	-0.493	-0.490	-0.379	-0.161
VI. Market Adjustments to Static Analysis - (C)	-0.358	-0.347	-0.400	-0.420	-0.406	-0.387	-0.240	-0.526	-0.493	-0.490	-0.379	-0.157
VI. Market Adjustments to Static Analysis - (D)	-0.357	-0.349	-0.403	-0.423	-0.406	-0.390	-0.243	-0.527	-0.493	-0.491	-0.371	-0.150
VII. Carbon Price-Induced Abatement (Avoided RECs)	-0.036	-0.036	-0.036	-0.036	-0.036	-0.036	-0.036	-0.036	-0.036	-0.036	-0.036	-0.036
Total Net Change in Customer Costs (A)	**-0.190**	**-0.445**	**-0.420**	**-0.407**	**-0.449**	**-0.367**	**-0.030**	**-0.287**	**-0.235**	**-0.228**	**-0.089**	**0.105**
Total Net Change in Customer Costs (B)	**-0.187**	**-0.281**	**-0.302**	**-0.306**	**-0.319**	**-0.276**	**-0.030**	**-0.317**	**-0.282**	**-0.279**	**-0.170**	**0.059**
Total Net Change in Customer Costs (C)	**-0.187**	**-0.257**	**-0.275**	**-0.281**	**-0.286**	**-0.251**	**-0.064**	**-0.330**	**-0.295**	**-0.291**	**-0.174**	**0.034**
Total Net Change in Customer Costs (D)	**-0.185**	**-0.158**	**-0.199**	**-0.215**	**-0.202**	**-0.190**	**-0.082**	**-0.353**	**-0.326**	**-0.324**	**-0.218**	**-0.003**

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Dr. Samuel Newell, a Principal of The Brattle Group, is an economist and engineer with 20 years of experience in electricity wholesale markets, the transmission system, and RTO/ISO rules. He supports clients throughout North America in regulatory, litigation, and business strategy matters involving wholesale market design, generation asset valuation, transmission development, integrated resource planning, demand response programs, and contract disputes. He has provided testimony before the FERC, state regulatory commissions, and the American Arbitration Association.

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About Brattle

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