Revenue Allocation and Seams Options

PRESENTED TO
IPPTF Stakeholders

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THE Brattle GROUP

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Agenda

Revenue Allocation

- Scope
- Findings, including zonal price changes
- Recommendations

Seams Issues

- Scope
- Findings
- Recommendations

Revenue Allocation

Allocation Design Objectives

Allocation mechanisms can be evaluated against at least two design objectives

- **Aligning LBMPs with the marginal cost of serving load**, to incentivize customers to reduce emissions when economic to do so (accounting for externalities)
- **Avoiding major cost shifts among customers**, as carbon charges will impact customers costs, and the allocation of carbon residuals/funds may moderate that impact

Review of Allocation Options

Least levelized net effect[1]

Most Levelized net effect

Allocation Approach	Description
(A) Load-Ratio Allocation	Each LSE receives the same $/MWh residual allocation
(B) Proportional Percentage Levelization Allocation	All LSEs face same % increase in net energy payments over non-carbon LBMPs; that is, equalize (LBMPc – $/MWh Residual Allocation) / (LBMP – LBMPc)
(C) Proportional Allocation	Allocation covers equal % of carbon payments; that is, equalize ($/MWh Residual Allocation) / LBMPc
(D) Levelizing Allocation	Each LSE faces the same $/MWh net carbon payments

NYISO Draft Recommendations propose **Levelizing Allocation** because it prioritizes avoiding major cost shifts across zones, despite eliminating an efficient price signal that internalizes the costs of CO_2 emissions

Notes:

1. Levelized w.r.t. net carbon payments (LMBPc – $/MWh Allocated Residuals), not w.r.t. a comparison to an alternative (unobservable) world without carbon charges and associated differences in RECs/ZECs/TCCs/changes in supply & demand.
2. "LBMPc" refers to the carbon effect on LBMP, as determined by the marginal price-setting units' emission rates and carbon charges.

2025 Allocation Comparison: Energy Payments before Allocation

- The following 4 slides derive the net customer carbon payments (net of allocation) through a series of steps, starting here with the energy payments before allocation

- In 2025, NYISO will observe LBMPs in the market and determine the LSE energy payments that account for the effects of the carbon charge, but not yet the allocated residuals

- LSE energy payments before allocated residuals are ~$9.6 billion in 2025
  - Upstate: $2.7 billion (5.2¢/kWh)
  - Downstate: $6.9 billion (7.0¢/kWh)

		Applicable to All Allocation Approaches
LSE Energy Payments Before Allocated Residuals		
Upstate	*($ million)*	$2,672
Downstate	*($ million)*	$6,907
NYCA Total	***($ million)***	**$9,579**
Upstate	*(¢/kWh)*	5.17
Downstate	*(¢/kWh)*	7.01
NYCA Total	***(¢/kWh)***	**6.38**

2025 Allocation Comparison: Gross Carbon Payments

- NYISO will then calculate the carbon effect on LBMPs (LBMPc) based on the MERs in each hour to determine the LSE Gross Carbon Payments
- NYCA-wide gross carbon payments are $2,690 million in 2025
  - Upstate: $800 million (1.5 ¢/kWh)
  - Downstate: $1,890 million (1.9 ¢/kWh)

		Applicable to All Allocation Approaches
LSE Energy Payments Before Allocated Residuals		
Upstate	*($ million)*	$2,672
Downstate	*($ million)*	$6,907
NYCA Total	***($ million)***	**$9,579**
Upstate	*(¢/kWh)*	5.17
Downstate	*(¢/kWh)*	7.01
NYCA Total	***(¢/kWh)***	**6.38**
LSE Gross Carbon Payments		
Upstate	*($ million)*	$798
Downstate	*($ million)*	$1,888
NYCA Total	***($ million)***	**$2,685**
Upstate	*(¢/kWh)*	1.54
Downstate	*(¢/kWh)*	1.92
NYCA Total	***(¢/kWh)***	**1.77**

2025 Allocation Comparison:
Allocated Residuals

- Total carbon residuals of $1,590 million to be allocated to NYCA load
- Upstate/Downstate allocation depends on the approach
  - *(A) Load-Ratio*: **Equal** residual allocation of 1.06 ¢/kWh
  - *(B) Proportional % Levelization*: **0.14¢/kWh** more allocated to Downstate than to Upstate
  - *(C) Proportional:* **0.22¢/kWh** more allocated to Downstate than to Upstate
  - *(D) Levelizing*: **0.37¢/kWh** more allocated to Downstate than to Upstate
- Choice of approach shifts allocations between Upstate vs. Downstate customers by up to $126 million

		Applicable to All Allocation Approaches			
LSE Energy Payments Before Allocated Residuals					
Upstate	*($ million)*	$2,672			
Downstate	*($ million)*	$6,907			
NYCA Total	***($ million)***	**$9,579**			
Upstate	*(¢/kWh)*	5.17			
Downstate	*(¢/kWh)*	7.01			
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Downstate	*($ million)*	$1,888			
NYCA Total	***($ million)***	**$2,685**			
Upstate	*(¢/kWh)*	1.54			
Downstate	*(¢/kWh)*	1.92			
NYCA Total	***(¢/kWh)***	**1.77**			
		(A) Load-Ratio Allocation	**(B) Proportional % Levelization**	**(C) Proportional Allocation**	**(D) Levelizing Allocation**
LSE Allocated Residuals					
Upstate	*($ million)*	$548	$500	$473	$422
Downstate	*($ million)*	$1,045	$1,092	$1,119	$1,170
NYCA Total	***($ million)***	**$1,592**	**$1,592**	**$1,592**	**$1,592**
Upstate	*(¢/kWh)*	1.06	0.97	0.92	0.82
Downstate	*(¢/kWh)*	1.06	1.11	1.14	1.19
NYCA Total	***(¢/kWh)***	**1.06**	**1.06**	**1.06**	**1.06**

Equal ¢/kWh

Equal % cost increase due to carbon (see next slide)

Net Carbon Payments equal on ¢/kWh basis (see next slide)

Equal on proportional basis to Gross Carbon Payments (see box above)
$473/ $798= 59%
$1,119/ $1,888= 59%

Note: Upstate includes Zones A-E and Downstate includes Zones F-K

2025 Allocation Comparison: Net Carbon Payments

- Total net carbon payments of $1,100 million across NYCA ($2,690m gross – $1,590m residuals)

- Upstate/Downstate net carbon payments depend on approach
  - *(A) Load-Ratio*: Downstate net payments are **0.38¢/kWh** higher than Upstate
  - (*B) Proportional % Levelization*: Downstate net payments are **0.23¢/kWh** higher than Upstate
  - *(C) Proportional*: Downstate net payments are **0.15¢/kWh** higher than Upstate
  - *(D) Levelizing*: **Equal** net payments of 0.73 ¢/kWh

		Applicable to All Allocation Approaches
LSE Energy Payments Before Allocated Residuals		
Upstate	*($ million)*	$2,672
Downstate	*($ million)*	$6,907
NYCA Total	***($ million)***	**$9,579**
Upstate	*(¢/kWh)*	5.17
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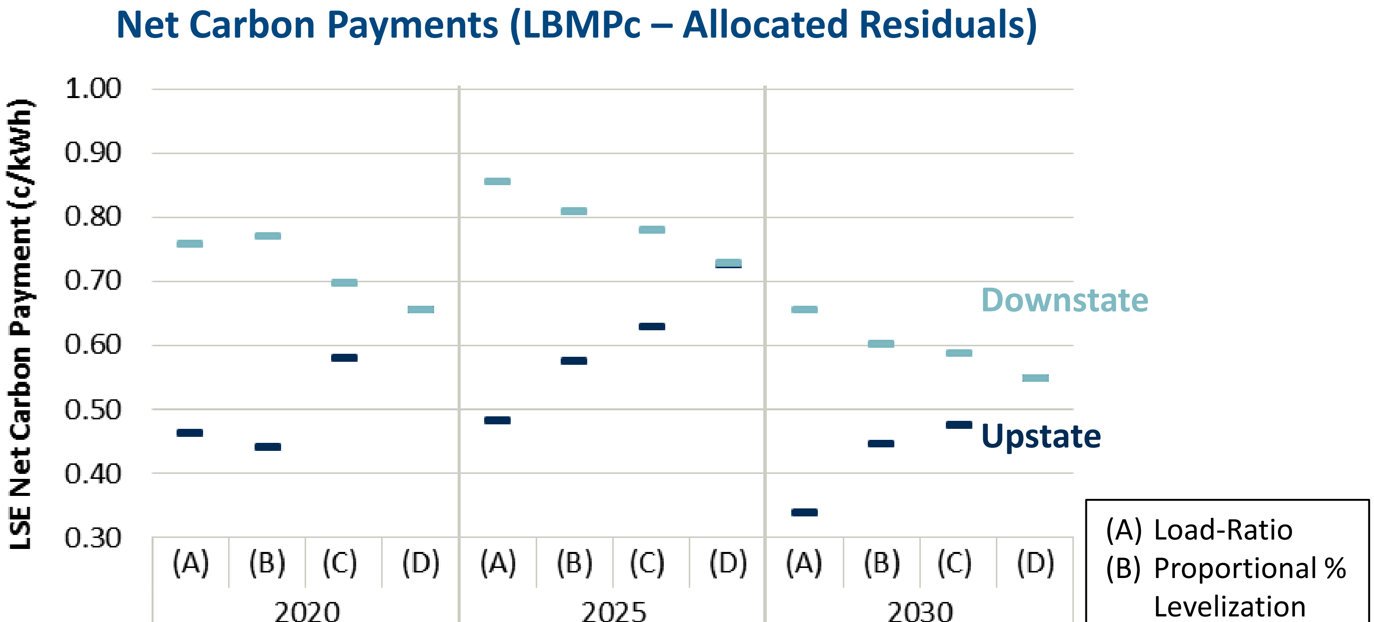
		(A) Load-Ratio Allocation	(B) Proportional % Levelization	(C) Proportional Allocation	(D) Levelizing Allocation
LSE Allocated Residuals					
Upstate	*($ million)*	$548	$500	$473	$422
Downstate	*($ million)*	$1,045	$1,092	[illegible]	[illegible]
NYCA Total	***($ million)***	**$1,592**	**$1,592**		
Upstate	*(¢/kWh)*	1.06	0.97		
Downstate	*(¢/kWh)*	1.06	1.11		
NYCA Total	***(¢/kWh)***	**1.06**	**1.06**		
LSE Net Carbon Payments					
Upstate	*($ million)*	$250	$297	$325	$375
Downstate	*($ million)*	$843	$796	$768	$718
NYCA Total	***($ million)***	**$1,093**	**$1,093**	**$1,093**	**$1,093**
Upstate	*(¢/kWh)*	0.48	0.58	0.63	0.73
Downstate	*(¢/kWh)*	0.86	0.81	0.78	0.73
NYCA Total	***(¢/kWh)***	**0.71**	**0.71**	**0.71**	**0.71**
% Change in LSE Energy Payments					
Upstate		13%	16%	17%	20%
Downstate		17%	16%	15%	14%
NYCA Total		16%	16%	16%	16%

Net Carbon Payments equal on ¢/kWh basis

Equal % cost increase due to carbon

Net Carbon Payments

- The allocation methods generally follow a similar pattern in net carbon cost outcomes across 2020, 2025 and 2030



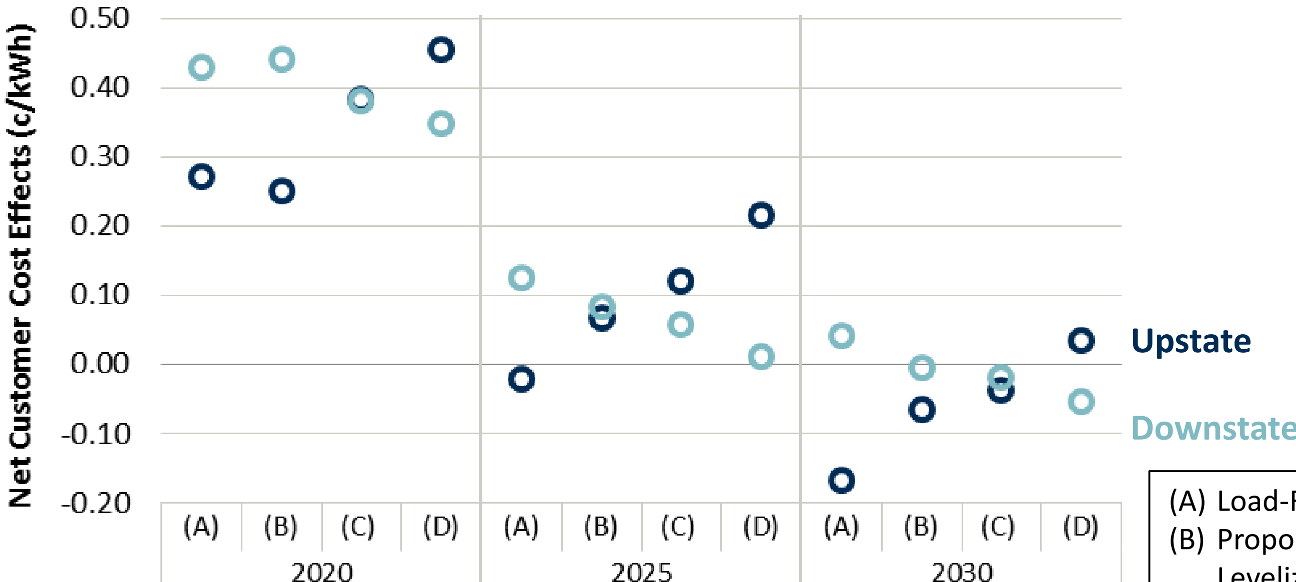
	2020 (A)	2020 (B)	2020 (C)	2020 (D)	2025 (A)	2025 (B)	2025 (C)	2025 (D)	2030 (A)	2030 (B)	2030 (C)	2030 (D)
Upstate	0.46	0.44	0.58	0.66	0.48	0.58	0.63	0.73	0.34	0.45	0.47	0.55
Downstate	0.76	0.77	0.70	0.66	0.86	0.81	0.78	0.73	0.66	0.60	0.59	0.55

Note: Proportional % levelization (B) can result in a wider range of costs than load-ratio share (A) if the % increase in gross energy payments due to carbon is greater Upstate than it is Downstate, such as in 2020.

Net Customer Costs with Carbon Charge vs. No Carbon Charge

- Net carbon payments do not fully describe how carbon pricing could affect customers costs relative to a world with no carbon pricing; net customer cost will also include reductions in REC/ZEC prices, higher TCC value, and dynamic effects on LBMPs
- Dynamic effects tend to reduce prices where carbon prices have the largest LBMP impacts, even before allocating residuals. Allocating residuals as if there were no dynamic effects (because they are not observable) can more than levelize net impacts under approach D.

Net Customer Cost Effects of Carbon Charge (incl. all offsets)



	2020				2025				2030			
	(A)	(B)	(C)	(D)	(A)	(B)	(C)	(D)	(A)	(B)	(C)	(D)
Upstate	0.27	0.25	0.38	0.46	-0.02	0.07	0.12	0.22	-0.17	-0.06	-0.04	0.04
Downstate	0.43	0.44	0.38	0.35	0.13	0.08	0.06	0.01	0.04	0.00	-0.02	-0.05

(A) Load-Ratio
(B) Proportional % Levelization
(C) Proportional
(D) Levelizing

Seams Issues

Review of Seams Issues and Approaches

Recap: Why do we need to consider seams issues?

- Charging only internal resources un-levels the playing field between internal resources and external ones. It shifts production outside NY (imports ↑, exports ↓), increases production costs, and leaks emissions

NYISO considered two approaches to re-leveling the playing field

- **External transactions compete on a status-quo basis ("Option 1").** Assess charges on imports (or credits on exports) such that all effects of carbon charges are invisible to imports and exports and imports/exports remain unchanged
- **External transactions compete on a green power basis, accounting for all emissions and NY's view of their externalities ("Option 2").** Levy import charges and export credits based on the marginal emissions consequences of transactions; this favors clean imports and exports when they provide cost-effective abatement

NYISO Draft Recommendations propose **Option 1**, and that was assumed in the MAPS analysis presented last week by "locking" Base Case external transactions

Key Concepts with Option 2

The emissions rate applied to imports/exports in Option 2 should be based on the *marginal emissions consequences* of the transaction

- Not unit-specific emissions rates, else invite resource shuffling
  - For example, all nuclear plants in PJM could sell into NY (while NY fossil exports)
  - This would shuffle resources and emissions in an accounting sense without actually decreasing emissions, in spite of large wealth transfers
- Not necessarily the marginal resource in the neighboring region.
  - For example, importing energy from Ontario could cause Ontario to sell less to MISO

Marginality must be considered in the operating timeframe, not investment timeframe

- Suppose there are incremental investment possibilities but no existing, underutilized low-emitting resources that could produce more energy if only offered a higher price (i.e., clean resources are already generating to maximum capability under given constraints)
- In that case, setting a low import rate could cause unintended consequences, e.g., HQ diverts sales from NE to NY or ON diverts sales from MISO to NY. Thus the rate would have to be set closer to a gas-fired or other fossil emissions rate
- Setting a high import charge could discourage investment in low-emitting resources, but that can be addressed through external RECs or other mechanisms

High-Level Assessment of Option 2 Emission Reduction Opportunities

- Among NYISO's neighbors, we have not found evidence of underutilized low-emitting resources whose output could increase if only offered a higher price (i.e., NYISO's LBMP with carbon premium, while paying a low rate themselves).
- The only opportunity we have found to reduce emissions in the operating timeframe is reduce coal-based imports from PJM.
- This suggests no Option 2 emission reduction opportunities with any neighbor except PJM. Hence, it might make sense to diverge from Option 1 for PJM transactions, but not for others.

High-Level Estimate of Emission Reductions from Discouraging PJM Coal Imports

When PJM has coal on the margin, NYISO could apply a higher border charge reflecting coal's higher emission rate

- The higher border charge would reduce flows from PJM in those hours
- Imports would be replaced by lower-emitting resources in New York
- Emissions savings would reflect the difference in emission between PJM coal and the NY MER

To provide a high-level bounding of potential benefits relative to Option 1:

- We assume coal is marginal in PJM 33% of the time (based on 2017).
- For simplicity, we assume applying an import charge at a coal rate in those hours would eliminate all PJM imports.
  - Not knowing which hours PJM's coal tends to be marginal, we approximate the quantity of deterred imports by taking 1/3 of annual net imports from coal (roughly 8 TWh in our simulations, depending on the year, which is net of flow-throughs to ISO-NE)
  - Assume all coal imports (1.0 ton/MWh emission rate) are replaced by internal NYCA generation (at 0.4 tons/MWh NYCA MER)
- We optimistically assume NYISO could accurately implement Option 2 at hourly granularity to limit all imports
- We optimistically assume importers do not flow through other markets to avoid higher PJM-NYISO border charge

High-Level Estimate (cont.)

0 tons ⟷ 2 million tons

Factors leading to lower impact

- Implementation challenges:
  - Data may not be available for NYISO to identify PJM MERs at hourly granularity or with sufficient accuracy
  - Importers could flow through other markets (IESO) to avoid higher PJM-NYISO border charge
- Energy in Eastern PJM at the NY border is less coal-based than PJM's average
- Imports are a mix of coal and gas even if the last, marginal MW is coal

Factors leading to higher impact

- Implementation challenges are somehow overcome
- When coal is marginal all net imports are from coal (about 1,000 MW on average)

Note: Potential savings lower in 2020 at 1 million tons and higher in 2030 at 3 million tons due to increasing PJM imports

Customer Cost Implications of Option 2 at the PJM Border

Assuming Option 2's Implementation challenges could be overcome, customer costs could change as follows:

- **LBMPs:** Higher, as 2 to 5 TWh/yr reduction in imports (larger reduction in 2030 than 2020) increases NYCA generation and LBMPs
  - As a rough indicator, price increases might be about half the difference between our 2025 normal load and high load cases, where LBMPs rise $0.7/MWh (expected effect ~$0.4/MWh)
- **Carbon residuals:** Unlikely to change substantially
  - Residuals collected from increased internal generation (at NY MER) similar to residuals collected from imports under Option 1 (at NY MER)
  - The roughly 300 MW average increase in NY generation might be slightly higher up the supply curve, but the slightly higher emissions affects carbon revenues only on that 300 MW (unlike LBMP increases that affect all load in NY)
- **REC procurements:** External emissions reductions could translate to customer savings if state policy changed to fully recognize such reductions, and if that allowed customers to meet their decarbonization goals with fewer RECs (beyond CES)
  - For example, reducing emissions 2 million tons could avoid having to buy 6 TWh of RECs
  - Valued at $6.2/MWh REC cost estimated for 2025, that translates to ~$40 million/yr, worth $0.3/MWh bill savings to customers

Overall, we estimate that Option 2 would not decrease NYCA customer costs

Recommendations

We support NYISO’s proposal to implement Option 1 because

- Option 2 opportunities are limited, likely just to PJM coal
- There are major implementation challenges with Option 2:
  - Accurately determining the appropriate hourly marginal emission rate for imports and exports, given incomplete data on other markets
  - Incents importers to flow through other markets to avoid higher border charges
- Option 1 is relatively simple, transparent and implementable
  - May seem to miss cost-effective abatement opportunities, but it is unclear that such opportunities could be captured through an Option 2 approach

However, something should be done to complement Option 1 to provide a signal for new investment in low-emitting external resources (such as new hydro and transmission from HQ)

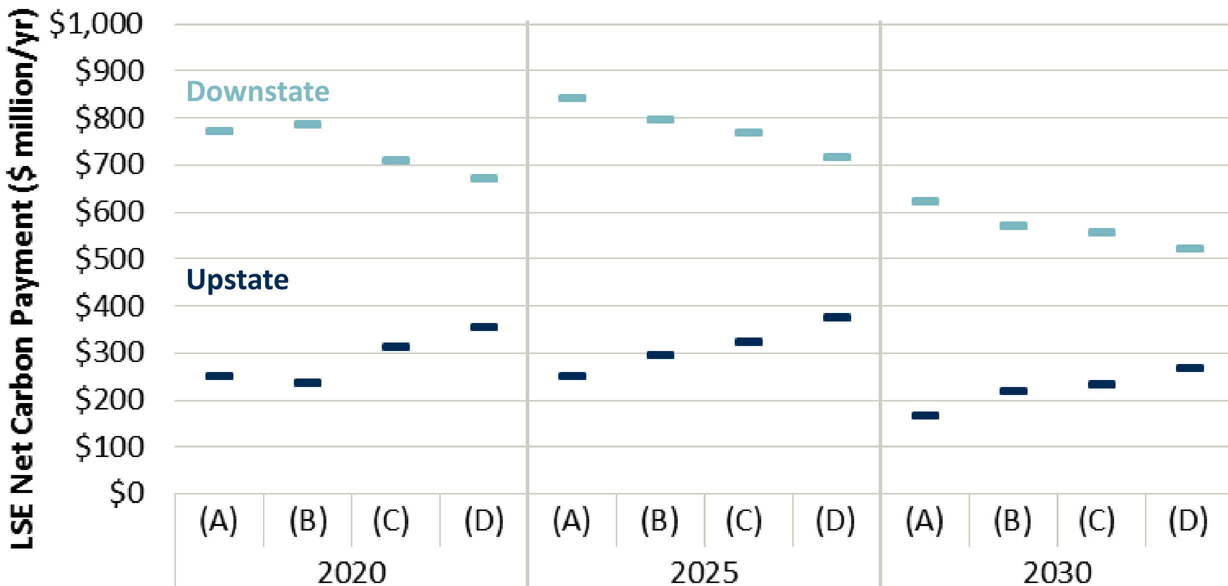
- Such as rewarding external RECs (and being willing to pay more for such RECs than for internal resources that have to be paid a higher energy price)

Appendix

Effects of Allocation Approach across 2020, 2025 and 2030

- The allocation methods generally follow a similar pattern in net carbon cost outcomes across 2020, 2025 and 2030

Total Bill Impacts (before static offsets and dynamic effects)



	2020 (A)	2020 (B)	2020 (C)	2020 (D)	2025 (A)	2025 (B)	2025 (C)	2025 (D)	2030 (A)	2030 (B)	2030 (C)	2030 (D)
Upstate	$251	$238	$313	$354	$250	$297	$325	$375	$166	$218	$232	$269
Downstate	$774	$786	$712	$670	$843	$796	$768	$718	$623	$571	$557	$520

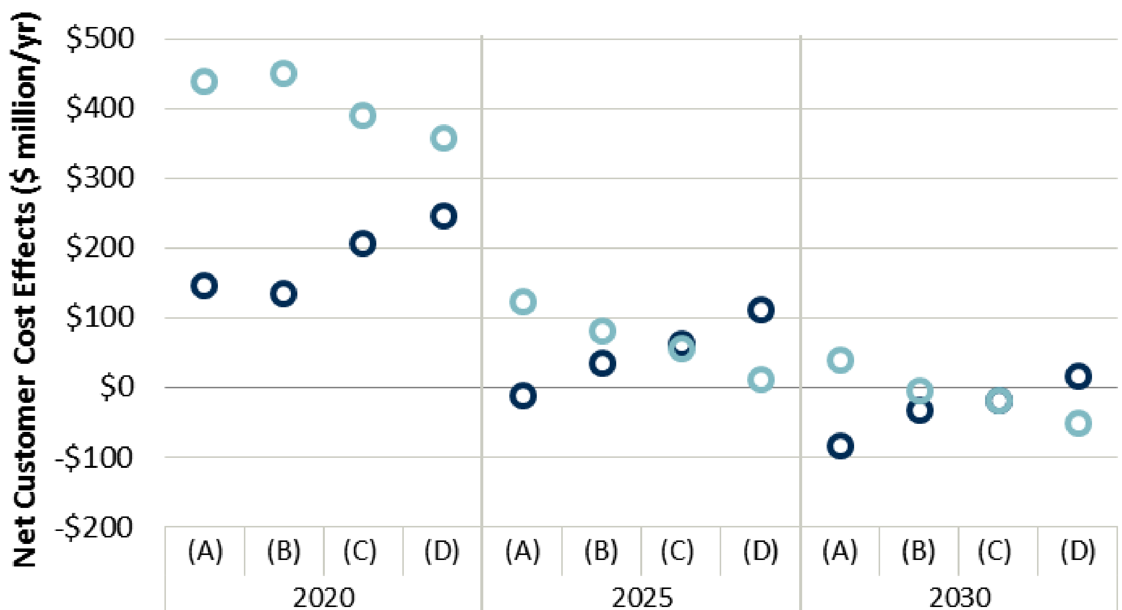
(A) Load-Ratio
(B) Proportional % Levelization
(C) Proportional
(D) Levelizing

Note: proportional levelization (B) can result in a wider range of costs than load-ratio share (A) if the % increase in gross energy payments due to carbon is greater Upstate than it is Downstate, such as in 2020.

Implications of Dynamic Effects

- Total bill impacts differ from net carbon payments due to effect of (1) lower REC/ZEC prices and (2) carbon-induced changes in resource mix and demand
- In 2020, bill impacts are $100 – 300 million higher Downstate than Upstate, compared to $350-650 million for net carbon payments (on previous slide)

Total Bill Impacts (including static offsets and dynamic effects)



	2020 (A)	2020 (B)	2020 (C)	2020 (D)	2025 (A)	2025 (B)	2025 (C)	2025 (D)	2030 (A)	2030 (B)	2030 (C)	2030 (D)
Upstate	$147	$136	$206	$246	-$10	$36	$62	$112	-$82	-$32	-$18	$17
Downstate	$440	$451	$390	$357	$124	$82	$57	$12	$41	-$5	-$18	-$50

(A) Load-Ratio
(B) Proportional % Levelization
(C) Proportional
(D) Levelizing

Allocation: Zonal Details, 2020

Customer Cost Impact of a $42/ton Carbon Charge, 2020
(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	1.644	1.442	1.427	1.486	1.378	1.488	1.730	1.698	1.709	1.713	1.746	1.789
II. Customer Credit from Emitting Resources - (A) Load-Ratio Allocation	-0.987	-0.987	-0.987	-0.987	-0.987	-0.987	-0.987	-0.987	-0.987	-0.987	-0.987	-0.987
II. Customer Credit from Emitting Resources - (B) Proportional % Levelization	-0.987	-1.043	-1.002	-1.029	-0.922	-0.984	-0.973	-0.953	-0.957	-0.958	-0.983	-0.977
II. Customer Credit from Emitting Resources - (C) Proportional Allocation	-0.987	-0.866	-0.857	-0.892	-0.828	-0.894	-1.039	-1.020	-1.027	-1.029	-1.049	-1.075
II. Customer Credit from Emitting Resources - (D) Levelizing Allocation	-0.987	-0.786	-0.771	-0.829	-0.722	-0.832	-1.074	-1.041	-1.053	-1.057	-1.090	-1.133
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	-0.096	-0.096	-0.096	-0.096	-0.096	-0.096	-0.096	-0.096	-0.096	-0.096	-0.096	-0.096
V. Increased TCC Value	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062	-0.062
Subtotal (A)	**0.498**	**0.296**	**0.282**	**0.340**	**0.232**	**0.342**	**0.584**	**0.552**	**0.563**	**0.567**	**0.600**	**0.643**
Subtotal (B)	**0.498**	**0.240**	**0.267**	**0.298**	**0.297**	**0.346**	**0.599**	**0.586**	**0.594**	**0.596**	**0.605**	**0.653**
Subtotal (C)	**0.498**	**0.417**	**0.411**	**0.435**	**0.392**	**0.436**	**0.532**	**0.519**	**0.524**	**0.526**	**0.539**	**0.556**
Subtotal (D)	**0.498**	**0.498**	**0.498**	**0.498**	**0.498**	**0.498**	**0.498**	**0.498**	**0.498**	**0.498**	**0.498**	**0.498**
DYNAMIC ANALYSIS												
VI. Market Adjustments to Static Analysis - (A)	-0.115	-0.031	-0.031	-0.030	-0.019	-0.032	-0.058	-0.082	-0.089	-0.092	-0.207	-0.193
VI. Market Adjustments to Static Analysis - (B)	-0.115	-0.031	-0.030	-0.029	-0.012	-0.030	-0.057	-0.084	-0.091	-0.095	-0.208	-0.195
VI. Market Adjustments to Static Analysis - (C)	-0.112	-0.038	-0.038	-0.037	-0.015	-0.039	-0.064	-0.084	-0.091	-0.094	-0.189	-0.172
VI. Market Adjustments to Static Analysis - (D)	-0.110	-0.042	-0.042	-0.041	-0.013	-0.044	-0.069	-0.086	-0.092	-0.095	-0.177	-0.158
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)	**0.379**	**0.261**	**0.246**	**0.306**	**0.210**	**0.306**	**0.523**	**0.466**	**0.471**	**0.471**	**0.390**	**0.446**
Total Net Change in Customer Costs (B)	**0.379**	**0.206**	**0.233**	**0.265**	**0.281**	**0.312**	**0.538**	**0.498**	**0.499**	**0.498**	**0.393**	**0.454**
Total Net Change in Customer Costs (C)	**0.382**	**0.376**	**0.370**	**0.395**	**0.373**	**0.393**	**0.464**	**0.431**	**0.430**	**0.428**	**0.346**	**0.380**
Total Net Change in Customer Costs (D)	**0.384**	**0.452**	**0.452**	**0.453**	**0.481**	**0.450**	**0.426**	**0.408**	**0.402**	**0.400**	**0.317**	**0.336**

Allocation: Zonal Details, 2025

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	-0.945	-0.963	-0.985	-0.958	-0.999	-1.038	-1.075	-1.087	-1.091	-1.137	-1.102
II. Customer Credit from Emitting Resources - (C) Proportional Allocation	-1.061	-0.885	-0.907	-0.934	-0.909	-0.957	-1.076	-1.100	-1.114	-1.117	-1.153	-1.156
II. Customer Credit from Emitting Resources - (D) Levelizing Allocation	-1.061	-0.764	-0.801	-0.847	-0.806	-0.885	-1.087	-1.127	-1.150	-1.156	-1.216	-1.221
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	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250	-0.250
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)	**0.182**	**-0.134**	**-0.096**	**-0.049**	**-0.090**	**-0.020**	**0.225**	**0.265**	**0.285**	**0.290**	**0.347**	**0.349**
Subtotal (B)	**0.182**	**-0.019**	**0.002**	**0.026**	**0.012**	**0.041**	**0.248**	**0.251**	**0.258**	**0.260**	**0.271**	**0.308**
Subtotal (C)	**0.182**	**0.042**	**0.058**	**0.078**	**0.061**	**0.084**	**0.209**	**0.226**	**0.232**	**0.234**	**0.255**	**0.254**
Subtotal (D)	**0.182**	**0.162**	**0.164**	**0.165**	**0.164**	**0.155**	**0.198**	**0.199**	**0.195**	**0.195**	**0.192**	**0.189**
DYNAMIC ANALYSIS												
VI. Market Adjustments to Static Analysis - (A)	-0.103	0.064	0.060	0.057	0.057	0.090	-0.066	-0.263	-0.239	-0.239	-0.245	-0.079
VI. Market Adjustments to Static Analysis - (B)	-0.102	0.061	0.057	0.054	0.056	0.086	-0.070	-0.264	-0.240	-0.240	-0.234	-0.074
VI. Market Adjustments to Static Analysis - (C)	-0.101	0.060	0.055	0.052	0.056	0.085	-0.071	-0.264	-0.240	-0.240	-0.232	-0.066
VI. Market Adjustments to Static Analysis - (D)	-0.099	0.057	0.052	0.049	0.056	0.082	-0.075	-0.266	-0.241	-0.241	-0.223	-0.058
VII. Carbon Price-Induced Abatement (Avoided RECs)	-0.002	-0.002	-0.002	-0.002	-0.002	-0.002	-0.002	-0.002	-0.002	-0.002	-0.002	-0.002
Total Net Change in Customer Costs (A)	**0.077**	**-0.072**	**-0.038**	**0.005**	**-0.036**	**0.067**	**0.157**	**0.000**	**0.043**	**0.049**	**0.100**	**0.268**
Total Net Change in Customer Costs (B)	**0.079**	**0.040**	**0.056**	**0.078**	**0.066**	**0.126**	**0.176**	**-0.016**	**0.015**	**0.018**	**0.034**	**0.231**
Total Net Change in Customer Costs (C)	**0.079**	**0.099**	**0.111**	**0.128**	**0.115**	**0.167**	**0.136**	**-0.041**	**-0.011**	**-0.009**	**0.020**	**0.186**
Total Net Change in Customer Costs (D)	**0.081**	**0.217**	**0.214**	**0.212**	**0.218**	**0.235**	**0.121**	**-0.069**	**-0.048**	**-0.048**	**-0.034**	**0.129**

Allocation: Zonal Details, 2030

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	-0.846	-0.895	-0.912	-0.887	-0.918	-0.976	-1.017	-1.033	-1.037	-1.080	-1.033
II. Customer Credit from Emitting Resources - (C) Proportional Allocation	-0.995	-0.819	-0.865	-0.884	-0.852	-0.890	-1.012	-1.032	-1.047	-1.050	-1.084	-1.065
II. Customer Credit from Emitting Resources - (D) Levelizing Allocation	-0.995	-0.722	-0.794	-0.824	-0.773	-0.833	-1.021	-1.052	-1.075	-1.080	-1.133	-1.104
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	-0.347	-0.347	-0.347	-0.347	-0.347	-0.347	-0.347	-0.347	-0.347	-0.347	-0.347	-0.347
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)	**0.200**	**-0.074**	**0.005**	**0.038**	**-0.016**	**0.044**	**0.234**	**0.266**	**0.285**	**0.290**	**0.334**	**0.302**
Subtotal (B)	**0.200**	**0.075**	**0.104**	**0.120**	**0.091**	**0.120**	**0.252**	**0.243**	**0.247**	**0.248**	**0.249**	**0.264**
Subtotal (C)	**0.200**	**0.102**	**0.134**	**0.148**	**0.127**	**0.148**	**0.216**	**0.229**	**0.233**	**0.235**	**0.245**	**0.232**
Subtotal (D)	**0.200**	**0.199**	**0.205**	**0.209**	**0.205**	**0.205**	**0.207**	**0.209**	**0.204**	**0.204**	**0.196**	**0.193**
DYNAMIC ANALYSIS												
VI. Market Adjustments to Static Analysis - (A)	-0.210	-0.121	-0.149	-0.162	-0.150	-0.147	-0.170	-0.347	-0.308	-0.307	-0.280	-0.123
VI. Market Adjustments to Static Analysis - (B)	-0.207	-0.125	-0.152	-0.166	-0.151	-0.151	-0.175	-0.349	-0.309	-0.308	-0.267	-0.119
VI. Market Adjustments to Static Analysis - (C)	-0.207	-0.125	-0.153	-0.167	-0.151	-0.152	-0.175	-0.349	-0.309	-0.307	-0.266	-0.114
VI. Market Adjustments to Static Analysis - (D)	-0.206	-0.128	-0.155	-0.169	-0.152	-0.155	-0.178	-0.350	-0.310	-0.308	-0.259	-0.108
VII. Carbon Price-Induced Abatement (Avoided RECs)	-0.018	-0.018	-0.018	-0.018	-0.018	-0.018	-0.018	-0.018	-0.018	-0.018	-0.018	-0.018
Total Net Change in Customer Costs (A)	**-0.027**	**-0.213**	**-0.162**	**-0.142**	**-0.183**	**-0.122**	**0.045**	**-0.099**	**-0.041**	**-0.035**	**0.036**	**0.161**
Total Net Change in Customer Costs (B)	**-0.025**	**-0.068**	**-0.066**	**-0.064**	**-0.078**	**-0.050**	**0.059**	**-0.123**	**-0.080**	**-0.078**	**-0.036**	**0.127**
Total Net Change in Customer Costs (C)	**-0.025**	**-0.041**	**-0.037**	**-0.037**	**-0.042**	**-0.022**	**0.023**	**-0.138**	**-0.094**	**-0.091**	**-0.039**	**0.100**
Total Net Change in Customer Costs (D)	**-0.023**	**0.053**	**0.032**	**0.022**	**0.036**	**0.033**	**0.011**	**-0.159**	**-0.123**	**-0.122**	**-0.081**	**0.067**

Seams Issues: Assumed External Transactions

Annual Net Imports from Neighboring Systems (TWh)

	2020	2025	2030
PJM	9.6	10.7	17.1
IESO	6.4	-1.0	3.3
ISO-NE	-2.8	-1.3	-2.3
HQ	11.3	11.3	11.3

Sources and Notes:
Per MAPS modeling

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