The Brattle Group, Daymark Energy Advisors, and Resources for the Future Carbon Charge Analysis Summaries and Synthesis[1]

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I. Study Summaries

A. Brattle Analysis

In April 2018, the NYISO released the Carbon Pricing Straw Proposal. This proposal outlined how carbon pricing could be incorporated into NYISO's wholesale markets. As part of the IPPTF Issue Track 5 Scope (Estimate Effects of Carbon Pricing), NYISO retained Brattle to conduct an analysis of the estimated effects of the proposal on customer costs and emissions.

The analysis to date evaluated the effects of carbon pricing in 2020, 2025, and 2030 under "most likely" reference conditions with CES and RGGI and other policies in place (as well as several alternative scenarios). Under Brattle's direction, NYISO staff ran cases in GE-MAPS without the carbon price and a case with the carbon price to evaluate the effects on dispatch, emissions, and LBMPs. They then ran additional cases with assumed changes in supply in response to the carbon price. In all cases with carbon prices, hourly external transactions were specified to equal the hourly transactions from an otherwise equivalent run without carbon charges in order to reflect NYISO's recommended approach for external transactions. Brattle used the results of the MAPS runs to evaluate the likely extent of dynamic responses, and ultimately the effect on customer costs and emissions. Customer costs accounted for changes in energy prices, customer carbon credits, lower ZEC and REC prices, and changes in TCC value.

The study indicates that carbon pricing would have a minor effect on customer costs, especially in the long run as supplies adjust. Although LBMPs increase with a carbon charge, several offsetting factors provide customer benefits. Net customer costs would rise 0.38 cents/kWh in 2020 (+2.2%), 0.07 cents/kWh in 2025 (+0.4%), and fall 0.02 cents/kWh in 2030 (-0.1%). Carbon charges would

[1] This summary was prepared by The Brattle Group, Daymark Energy Advisors, Resources for the Future and NYISO staff in response to requests from IPPTF participants. The summaries and other discussions of the studies were prepared by the respective authors and reflect the author's view of their analysis and the conclusions that can be drawn from the respective studies. Please note that this summary is a draft for discussion purposes only and any specific questions should be directed to the authors of the individual studies.

lead to incremental internal emissions reductions of 4% by 2030 (-0.8 million tons from a baseline of 21 million tons internal emissions). 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

B. RFF Analysis

Daniel Shawhan, Paul Picciano, and Karen Palmer of Resources for the Future (RFF) are using the Engineering, Economic, and Environmental Electricity Simulation Tool (E4ST) to simulate the effects of the policy. The E4ST software and the current E4ST input dataset of the Eastern Interconnection together constitute a detailed physics- and economics-based model of the power system and power markets in the Eastern Interconnection. The model simultaneously predicts how the system will operate and what generator investment and retirements will occur in successive future periods, typically five-year periods through as far as 2050. E4ST models 40 representative hours each year, chosen and weighted to represent the frequency distribution of demand, wind, and solar, and to oversample high-scarcity hours. The model incorporates an air pollution transport-and-fate model to estimate health effects. E4ST.com describes the E4ST model in more detail.

The RFF study of the proposed NY carbon pricing policy has two goals. The first is to learn more about the nature of the effects of such a policy, to help inform decisions and further research about policies that are at least somewhat similar to the proposed New York policy, regardless of where in the world they are considered. The second is to provide estimates of the effects of the policy on consumers, generation owners (including a focus on NY nuclear and on renewables), interstate electricity flows, emissions, health, and total welfare in New York and beyond. The study also explores the interactions between the NY policy and the RGGI regional carbon emission cap-and-trade program.

In order to achieve these goals, the study involves making observations about the relationships between simulated effects of the policy, to determine the signs of the relationships between them, and why they affect each other in the ways that they do. For some of the effects, this exercise requires examination of the detailed results for geographic subsets of the system and for individual generator types. The RFF study focuses on the effects of the policy compared to a "business as usual" scenario without the policy, as of 2025. The sections below report some of the results. They are an improvement over the preliminary results presented to the New York IPPTF on September 24, 2018, and they replace those prior results.

The RFF study finds a carbon charge would increase net customer costs by $0.8/MWh in 2025. Average New York LBMPs are found to rise $22.2/MWh. The study finds carbon emission fall by

0.2 million tons within New York and 1.2 million tons across the Eastern Interconnection. The policy is found to cause minimal changes in the RGGI price, and does not cause the RGGI Emission and Cost Containment Reserves to trigger under the circumstances assumed for the analysis reported in this document.

RFF is also preparing an academic paper that considers the effects of the policy under different possible future circumstances. One of the findings is that the policy would be likely to reduce CO_2, SO_2, and NO_X emissions in NY, the rest of RGGI, and the rest of the Eastern Interconnect—*negative* emission leakage—through an interesting effect on the distribution of locational marginal electricity prices outside of the RGGI states. Once completed, this paper will be available at www.rff.org.

C. Daymark Analysis

Daymark Energy Advisors, Inc. evaluated the direct economic and bulk power system impacts of implementing a carbon charge through the NYISO markets. The study focused on the difference in outcomes between two cases: a "status quo" case, which assumes state policies are met and the carbon charge is not implemented, and a "with carbon charge" case featuring the addition of the proposed carbon charge. Carbon pricing effects were evaluated over the study period 2021-2025, 2030, and 2035. Performance metrics were selected to characterize the impact of the carbon charge on the market, consumers, and economic efficiency. These performance metrics included CO_2 emissions, production costs, average LBMPs, zonal capacity prices, customer credits from emitting resources, resource gross margin (revenues minus fuel costs), net exports, quantity and location of market-based entry, and renewable production. Based on the sensitivity of the performance metrics to variances in the input assumptions, Daymark tested certain key inputs or assumptions in scenarios.

Daymark used a suite of modeling tools iteratively to model each case, which include the EPIS AURORA Zonal Model, DaymarkEA CapMarket Model, and DaymarkEA GasBasis Model. Results from the suite of models are compiled for the Status Quo case. For the Carbon Charge case, Daymark first calculated a marginal carbon charge (MCC) border adjustment. The MCC border adjustment was designed to capture the initial NYISO proposal to post a forecast of carbon charges to be applied to Day Ahead and Real Time transactions. Therefore, Daymark estimated a schedule of border charges, rather than fixing net imports. This approach approximates the impact of charges on external transactions.

Daymark found that the performance of the carbon charge is particularly sensitive to the implementation of the border adjustment mechanism; the impact of the estimation error is asymmetric and tends to increase costs and emissions. The results suggest that trading post carbon charge could result in higher in-state CO_2 emissions, even while lowering emissions over the broader market region. Slightly less than half of the wholesale cost increase to customers is offset via allocation of the carbon charge residuals. Increased gross margins of in-state resources are likely insufficient to overcome the non-market barriers that exist in building transmission and siting, reducing potential that a carbon charge would lead to optimal development of capital to renewable projects. No market-based entry occurs during the study period. On its own, the carbon charge is not likely to create material improvements over the status quo. Combined with other modifications to the market rules and to the implementation of public policy through direct contracting, the carbon charge could produce more cost-effective outcomes for the state. At present, one of the most compelling reasons to pursue the carbon charge may be as mitigation against the risk of future FERC interventions to address concerns regarding out-of-market public policy support for select resources.

II. Cross-Study Comparison

A. Modeling Approach

High-Level Structure

At a high level, all three studies rely on similar modeling techniques to evaluate the implications of a carbon charge in NYISO's energy markets. All three studies utilize production cost models, supplemented with capacity market and new entry analyses. All three studies isolate the effects of a carbon charge by modeling both a "base case" without carbon pricing and a "change case" with carbon pricing.

The studies differ in the years evaluated. The Brattle study evaluates effects in 2020, 2025, and 2030. Daymark's analysis evaluates all years 2021 – 2025, 2030, and 2035. RFF's analysis focuses solely on 2025.

While all three studies focus on effects within New York, they differ in how other adjacent systems are modeled. RFF's analysis considers effects across the entire Eastern Interconnect. Daymark evaluates effects in all systems neighboring New York (ISO-NE, PJM, Ontario, PJM, Hydro Quebec, and "Other"). The Brattle analysis focuses solely on effects within New York, under the assumption that a carbon charge will not affect neighboring systems due to the application of a border adjustment. Each study's treatment of borders is discussed in further detail below.

The three studies also differ in how they model dynamic effects of a carbon charge on investment and retirement decisions, as discussed below.

Treatment of the Borders

A point of divergence across the studies is treatment of the borders. The Brattle analysis models no change in net imports from neighboring systems due to a carbon charge, under the assumption that border adjustments can be applied in such a way that flows in a carbon charge "change case" are unchanged from a "base case" without carbon pricing. The analysis first identified flows in the "base case", and then locked flows in the "change case" to the same level as in the "base case."

The RFF researchers' treatment of the borders assumes border prices are set such that net imports in each hour equal what they would be if the carbon adder were suddenly removed. The RFF researchers believe that modeling border flows at the level they would be if the carbon adder were removed suddenly is consistent with the policy, rather than what they would be if the carbon adder had never been implemented. The RFF researchers believe the policy would affect border flows by affecting the generation fleet. Modeling followed an iterative process to reach a close approximation of the equilibrium between the effects of the policy on the generation fleet and on border flows. This involves iteration because each of those affects the other. First, the simulation was run without the policy and with endogenous generator construction and retirement (starting from the 2020 fleet), and the hourly net flows were observed at each border (one with each neighboring control area) in each hour. Second, the simulation was run again with endogenous generator construction and retirement but with the policy in place, which involves the charges on New York power plant CO_2 emissions and hourly net imports at each border constrained to equal those observed in the first step. Third, the simulation was run a third time with the generation fleet resulting from the second simulation but with the policy suddenly removed, to develop updated estimates of the border flows under the policy, and of the policy's border prices. Fourth, the simulation was run a fourth time just like the second time, but with imports and assumed RGGI price based on the immediately preceding simulation (the third) rather than on the first simulation. Fifth, the third and fourth steps were repeated three more times for a total of ten simulations, to iterate to a close approximation of the equilibrium between the effects of the policy on the generation fleet and the border flows.

Daymark's treatment of the border attempts to account for the potential scheduling challenges of border pricing implementation. Daymark uses a "two stage" approach to simulating the border. The first stage assumes a "universal" carbon charge across all modeled regions (New York and all neighbors). Upstate and Downstate hourly marginal proxy units are identified (these could be internal to New York or external, which is different from the initial NYISO carbon charge proposal), as well as their emissions rate. The second stage applies the hourly schedule of Upstate and Downstate border charges ($/MWh) based on the emissions rate of the proxy units identified in Stage 1 and the simulation is re-run, removing the assumption of "universal" carbon charges for resources external to New York. Daymark found an average annual marginal emissions rate of 0.52 – 0.6 tons/MWh across years for the modeled "East" zone and 0.36 – 0.49 tons/MWh across years for the modeled "West" zone.

Additionally, Daymark ran an alternative Stage 1 border adjustment modeling approach that identified Upstate and Downstate hourly marginal proxy units from the Status Quo case (assumes only current RGGI priced are applied to resources in New York and its neighbors). Stage 2 then applies the hourly schedule of Upstate and Downstate border charges ($/MWh) based on the emissions rate of the proxy units identified in Stage 1 and the simulation is re-run, adding a carbon charge to internal resources. Both MCC forecast methods result in increased net exports and do not assume friction-free trades at the borders. Daymark's methods attempt to reflect that hourly border charges may be greater or lesser than the "true" hourly values in any given hour. Mismatches between the actual carbon costs of the other New York generators and the forecast carbon charges will cause volatility along the New York border. Daymark completed further sensitivities to its border charge application to smooth out hourly impacts. These sensitivities, which included using an annual average border charge, monthly average border charges, and a 50% increase and 50% decrease to the annual average border charge in 2030, support the conclusions that the carbon charge performance is sensitive to how the border adjustment mechanism is implemented.

Incorporation of Dynamic Effects

The studies are different in the extent to which dynamic effects are considered and how dynamic effects are modeled.

The Daymark analysis accounts for how a carbon charge results in changes in investment (i.e. market-based new entry), but finds no market-based entry occurs over the study period. The analysis does not account for any other dynamic effects. Daymark also analyzes the amount of collected carbon charges that are refunded to customers.

The RFF analysis accounts for several dynamic effects including:

- Changes in ZEC price
- Changes in REC prices (separately for New York and each of several regions of the Eastern Interconnection)
- Change in the Regional Greenhouse Gas Initiative allowance price
- Changes in capacity market prices (separately for New York and each of several regions of the Eastern Interconnection)
- Changes in generator investment and retirement
- Changes in electricity flows including cross-border flows.

The Brattle analysis accounts for dynamic effects including changes in ZEC and REC prices; market adjustments such as nuclear retention, incremental renewable entry, and load elasticity; and savings due to carbon-price induced carbon abatement.

B. Analytical Results

Change in LBMPs

All studies find higher state-wide LBMPs resulting from a carbon charge, and find increases in LBMP are most significant Downstate. The Brattle analysis finds LBMPs would rise by less than the Daymark and RFF studies.

Differences in changes in LBMPs can be at least partly explained by differences in each study's modeling of the market heat rate. For example, because the RFF simulation model predicts both operation and investment, it utilizes each generator's historical realized average per-MWh heat rate rather than its incremental per-MWh heat rates and its no-load fuel usage. This may tend to overstate market incremental heat rates, which tend to be lower than average heat rates. For the same reason, the RFF modeling for this project also does not include unit commitment, which may miss some units being held on for minimum up-time constraints, thereby generating energy but ineligible to set the market price. These two features of the RFF approach do not predictably overstate the policy's effect on customer bills, because the no-load and constrained-on emission charges do appear in capacity and uplift charges, but these two features do overstate how much of that effect on customer bills is in LBMPs versus in uplift charges and other determinants of the bill.

Differences in changes in LBMPs can also be explained in part by assumptions regarding the net social cost of carbon in each study. The studies assume similar carbon charges through 2025. However, the Daymark study finds LBMP impacts would rise from 2025 – 2035, mostly due to the increasing net social cost of carbon that Daymark assumed over the study period. The net social cost of carbon was increasing due to the gross social cost of carbon growing more than RGGI, which was escalated at a rate of 8% per year after the last year reported in CARIS. In contrast, Brattle find lower carbon charges in 2030 than 2025 due to assumed increases in the RGGI price, resulting in carbon charges of \$45.4/ton in 2030 as compared to \$57/ton in 2030 assumed by Daymark.

Table 1
Comparison of State-Wide Increase in Wholesale Energy Prices Due to Carbon Charge (\$/MWh)

	2020	2021	2022	2023	2024	2025	2030	2035
Brattle	\$16.4					\$17.9	\$15.8	
Daymark		\$22	\$21	\$22	\$23	\$22	\$25	\$31
RFF						\$22.2		

Note:
Load-weighted increase in LBMPs. RFF results include effects of changes in investment and cross-border flows, Brattle results do not account for these effects. Nominal dollars.

Table 2
Carbon Charge Assumptions ($/MWh)

	2020	2021	2022	2023	2024	2025	2030	2035
Gross SCC								
Brattle	$47.3					$57.5	$69.3	
Daymark	$47	$48	$50	$53	$55	$57	$69	$84
RFF						$57		
RGGI Price								
Brattle	$5.6					$8.3	$23.9	
Daymark	$6	$6	$7	$7	$8	$8	$12	$18
RFF						$10		
New York Carbon Charge								
Brattle	$41.7					$49.2	$45.4	
Daymark	$41	$42	$43	$46	$47	$49	$57	$66
RFF						$47		

Note:
Load-weighted increase in LBMPs. RFF results include effects of changes in investment and cross-border flows, Brattle results do not account for these effects. Nominal dollars.

Change in Carbon Emissions

The three studies find similar reductions in system-wide carbon emissions due to a New York carbon charge. For example, in 2025 Brattle finds CO_2 emissions fall 1.5 million tons. RFF finds CO_2 emissions across the Eastern Interconnect fall by 1.2 million tons. Daymark finds that the modeled area CO_2 emissions, including New York, decreased in the same order of magnitude that Brattle and RFF report (reductions of less than one million metric tons across the study period). The distribution of where emission reductions occur is largely driven by differences in how each study models border adjustments.

Change in Customer Costs

Brattle and RFF both find aggregate customer costs would increase slightly in 2025 due to a carbon charge, increasing $0.7/MWh and $0.8/MWh respectively. Brattle finds customer cost impacts fall over time. Daymark does not report changes in customer costs. However, Daymark shows that the customer credit from emitting resources (carbon revenues refunded to loads) ranges from $7/MWh to $9/MWh (nominal dollars) over the study period.

Table 3
Comparison of Increases in Customer Costs Due to Carbon Charge ($/MWh)

	2020	2021	2022	2023	2024	2025	2030	2035
Brattle	$3.8					$0.7	-$0.2	
Daymark				Not Reported				
RFF						$0.8		

Note:
Nominal dollars.

Change in System Production Costs

The Brattle study finds negligible changes in annual system production costs (+/- $10 million) due to a carbon charge. The RFF estimate is within this range and finds that the policy would increase production costs by $7.2 million in the Eastern Interconnect in 2025. Daymark similarly finds system production costs change by +/- $30 million through 2025, increasing to $148 million by 2035. Changes in production costs within New York differ across studies due to different approaches to modeling the border. These estimates of production costs exclude costs associated with paying the carbon charge.

Collected Carbon Revenue

Brattle and RFF both find collected carbon revenues on the order of $1.5 billion per year. Daymark finds declining carbon revenues, falling from $1.4 billion in 2021 to $1.0 billion in 2035.

Table 4
Collected Carbon Revenue ($ millions)

	2020	2021	2022	2023	2024	2025	2030	2035
Brattle	$1,541					$1,592	$1,431	
Daymark		$1,399	$1,390	$1,338	$1,229	$1,086	$958	$1,030
RFF						$1,528		

Note:
Nominal dollars. Only includes revenues due to New York carbon charge; excludes carbon revenues to RGGI

Effect on REC and ZEC Prices

The Daymark study does not evaluate changes in REC and ZEC prices due to a carbon charge. While the analysis did not calculate the impacts on ZECs and RECs directly, Daymark found the following gross profit margin (revenue minus fuel costs) impacts: Upstate nuclear plants increased on average 70%; Upstate solar increased on average 48%; Upstate wind increased on average 46%; Downstate off-shore wind increased on average 47%; and Downstate solar increased on average 51%.

The RFF analysis finds the carbon charge would reduce REC prices from $43/MWh to $24/MWh and would reduce ZEC prices from $14/MWh to $0/MWh in 2025 (nominal $).

The Brattle analysis finds the carbon charge would reduce ZEC prices from $25/MWh to $12/MWh in 2025. The study finds REC prices would fall from $22/MWh to $3/MWh in 2020, $25/MWh to $7/MWh in 2025, and $28/MWh to $12/MWh in 2030.