Carbon Pricing Straw Proposal

A Report Prepared for the Integrating Public Policy Task Force

April 30, 2018

DRAFT FOR DISCUSSION PURPOSES ONLY

Table of Contents

Introduction

The State of New York is pursuing decarbonization of its economy with the goal of reducing carbon dioxide emissions 40% by 2030 and 80% by 2050, relative to 1990 levels. In support of this and other objectives, New York has adopted policies to reduce emission in the electric power sector, including the Clean Energy Standard. However, the wholesale electricity markets operated by the New York Independent System Operator (NYISO) do not reflect the full cost of carbon dioxide (CO_2) emissions. This limits the wholesale electric market's ability to signal cost-effective abatement options, and it suggests an opportunity to improve harmonization between wholesale energy markets and state policy objectives.

The Integrating Public Policy Task Force (IPPTF) was created as a forum for a joint NYISO/ New York State staff team (referred to as the Joint Staff team[1]) to solicit stakeholder feedback on concepts and proposals for incorporating the cost of carbon emissions into wholesale energy markets to better harmonize the state's energy policies and the operation of those wholesale markets. After a series of IPPTF meetings, the Joint Staff team drafted a work plan to:

> **"Identify the topics and timelines to further explore options to incorporate the cost of carbon into wholesale energy markets with the goal of contributing to achieving New York State's public policies, while providing the greatest benefits at the least cost to consumers and appropriate price signals to incentivize investment and maintain grid reliability."[2]**

The work plan identified five Issue Tracks focused on specific areas of stakeholder interest. Issue Track 1 required development of a straw proposal with a conceptual design for how to incorporate the cost of carbon into the NYISO-administered wholesale energy markets.

This straw proposal outlines a potential design for incorporating the cost of carbon emissions into the wholesale electricity markets (Straw Proposal). The Straw Proposal reflects stakeholder input and consideration of how a carbon price would interact with the existing NYISO wholesale energy market-related processes.[3] The Straw Proposal aims to incorporate the cost of carbon in a manner that (1) is economically efficient, (2) avoids major cost shifts among New York customers, (3) is transparent, and (4) provides market/regulatory stability. This Straw Proposal is a draft document designed to facilitate deeper discussions of the concepts with stakeholders.

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[1] The NYISO/New York State joint staff team is comprised of New York Independent System Operator, New York Department of Public Service and New York State Energy Research and Development Authority staff.

[2] IPPTF Work Plan, February 6, 2018. http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-02-12/Work%20Plan%20CORRECTED%20CLEAN%20%2020180206.pdf

[3] The Straw Proposal was developed based on knowledge and evaluation of all existing alternate proposals provided to the joint staff team on or before Thursday, November 30, 2017.

Concept for Carbon Pricing

The cost of carbon emissions could be incorporated into the NYISO-administered wholesale energy markets using a carbon price in dollars per ton of CO_2 emissions. The NYISO would apply a carbon price by debiting each energy supplier a carbon charge for its carbon emissions at the specified price as part of its settlement. Suppliers would embed these additional carbon charges in their energy offers (referred to as the supplier's carbon adder in $/MWh) and thus incorporate the carbon price into the commitment, dispatch, and price formation through the NYISO's existing processes. In addition to charging internal generators, the NYISO would charge imports for emissions and credit exports for avoiding other emissions to prevent the carbon charges on internal generation from causing emissions leakage and costly distortions.

Because the carbon charges on suppliers would increase the variable costs of carbon-emitting generation dispatched by the NYISO, it would raise the energy market clearing price whenever carbon-emitting resources are on the margin (referred to as the carbon effect on LBMPs). All suppliers, including clean energy resources, would receive the higher energy price, net of any carbon charges due on their emissions. Low-emitting New York resources, including efficient fossil units, renewables, hydropower, and nuclear generators, would benefit from higher net revenues. Loads would continue to be charged the LBMP for wholesale energy purchases, which would account for the carbon adder of the marginal units. The NYISO would return the carbon charge residuals, which are the sum of the carbon charges debited from suppliers, to the loads.[4]

Stakeholders presented two alternatives to carbon pricing at IPPTF meetings. The Long Island Power Authority (LIPA) proposed that RGGI allowances could be retired in equivalent quantities up to the carbon abatement needed to meet the Clean Energy Standard (RGGI allowance retirement proposal).[5] This adjustment could cause the RGGI allowance price to rise, potentially up to the $17/ton Cost Containment Reserve (CRR). This approach does not meet the IPPTF purpose because it would not provide a price high enough to substantially contribute to achieving New York State's public policies.[6] The electricity markets participating in RGGI offer limited carbon abatement opportunities in the price range expected for RGGI allowances absent supplemental Renewable Energy Credit (REC) payments. Furthermore, the RGGI allowance retirement proposal would be vulnerable to leakage in at least three ways: (1) via energy transactions across the uncontrolled RGGI seam; (2) via the automatic release of allowances once prices reach the CCR; and (3) via the RGGI governance process potentially expanding the number of allowances to maintain prices and quantities within the range the other states want. IPPTF Issue Track 4: Interactions with

[4] Residuals are the result of over (or under) collection in the NYISO markets. In this context, the residuals will be over collections that exist because the payments to suppliers do not equal the charges to loads.

[5] See Long Island Power Authority (2018). Harmonizing Carbon Prices and Expected CES Reductions. Presented to IPPTF, February 12, 2018. Posted at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-02-12/Harmonizing%20Carbon%20Prices%20and%20CES%20Reductions.pdf

[6] The CCR is much lower than the Social Cost of Carbon adopted by the PSC in the Clean Energy Standard proceeding.

Other State Policies and Programs will further consider interactions between the carbon pricing Straw Proposal and RGGI.

National Grid proposed the development of a Dynamic Forward Clean Energy Market (DFCEM).[7] As proposed, the DFCEM would be a NYISO-administered forward auction for zero-emission resources. It would recognize the carbon abatement value of clean energy resources by providing RECs to clean energy resources that would scale with the locational marginal emissions rate. While clean energy markets may complement market-wide carbon pricing, this proposal does not meet the IPPTF purpose because it does not incorporate the cost of carbon dioxide into the NYISO-administered wholesale energy markets. NYSERDA operates a competitive procurement process today that achieves many of the benefits of a centralized auction. Should stakeholders wish to discuss possible changes to REC products, those discussions should be part of IPPTF Issue Track 4: Interactions with Other State Policies and Programs.

Setting the Gross Social Cost of Carbon

The New York Public Service Commission (PSC) would set the Gross Social Cost of Carbon (SCC) pursuant to the appropriate regulatory process.

The NYISO would implement the full value of the Gross SCC once adopted, without an initial transition mechanism.

Application of the Carbon Price to Internal Suppliers

Proposal

All internal suppliers participating in the wholesale energy markets would be subject to carbon charges in the wholesale energy market equal to the product of the applicable carbon price and their point-of-production carbon emissions.[8]

The applicable carbon price would be based on the PSC's Gross SCC with adjustments for RGGI allowance prices for those suppliers required to hold RGGI allowances. Suppliers covered by RGGI (*e.g.*, currently, fossil-fuel-fired electric generating units with capacity of 25 MW or greater) would be charged the Gross SCC *minus* the most recently posted quarterly RGGI price. Suppliers not covered by RGGI would incur a carbon price equal to the Gross SCC.

[7] See National Grid (2018). Dynamic Forward Clean Energy Market (DFCEM). Presented to IPPTF, February 12, 2018. Posted at: http://www.nyiso.com/public/webdocs/markets_operations/committees/bic_miwg_ipptf/meeting_materials/2018-02-12/IPP_18_01_29_DFCEM%20Presentation.pdf

[8] "Point-of-production emissions" refer to the stack emissions, not lifecycle emissions, with a few exceptions discussed herein.

All internal suppliers participating in the wholesale markets would self-report their carbon emissions to the NYISO through a new data submission process. Self-reported emissions and the applicable carbon price would determine the carbon charges assessed in the NYISO settlements process. Just like today's NYISO settlements process, these settlements would be subject to true-ups as part of the normal billing processes. Self-reported emissions would be subject to verification, for example, with emissions data from the U.S. EPA's Clean Air Markets Division (CAMD) database.[9]

A few resource types' applicable emissions warrant special treatment to level the playing field and/or be consistent with state policies:

- **Tier 1 resources under the Clean Energy Standard** with point-of-production emissions, including biomass, biogas/landfill gas, and digesters, would not be assessed carbon charges consistent with their eligibility to receive Tier 1 Renewable Energy Credits via CES and their treatment under RGGI. This is equivalent to using lifecycle emissions for these resources.
- **Cogeneration** resources would only be assessed carbon charges on the portion of their carbon emissions associated with electrical generation.[10]
- **Behind-the-Meter Net Generation Resources** that participate in the NYISO wholesale markets and produces carbon emissions would be charged based on their net injections to the grid.

The NYISO would not have to change existing energy market mechanics or offer procedures. Suppliers would be expected to incorporate their carbon charges into each applicable component of their energy offers (*i.e.*, startup, minimum generation, and/or incremental cost curves). Supplier energy market payments would continue to be based on the full LBMP, which will rise due to the carbon charge if carbon-emitting resources are on the margin.[11]

Rationale and Alternatives Considered

The proposed approach has the following advantages over alternative approaches:

- Energy market prices would accurately account for the State-determined Gross Social Cost of Carbon; and,
- The proposal would only require minimal changes by the NYISO to the existing energy market operations and other NYISO market and planning processes (see discussion in Section VII below).

[9] Fuel consumption data from Form EIA-923 is also available for resources not tracked in the CAMD database (such as fossil-fired units smaller than 25 MW). The CAMD database tracks plant-level emissions for units over 25 MW on an ongoing hourly basis and is also used for RGGI compliance. Generators must report quarterly emissions to CAMD within 30 days of the end of each quarter. Emissions are tracked with Continuous Emissions Monitoring Systems (CEMS) using calculations and procedures that have been certified by the EPA. U.S. EPA, "Plain English Guide to the Part 75 Rule," June 2009.

[10] The U.S. EIA uses data on input fuel type, prime mover efficiency, and final electricity generation from Form EIA-923 to isolate the emissions from electricity generation, assuming that the remaining emissions are due to heat generation. U.S. Energy Information Administration, "Appendix C, Technical Notes, to the Electric Power Monthly," January 2018.; U.S. Environmental Protection Agency, "The Emissions and Generation Resource Integrated Database: Technical Support Document for eGRID with Year 2016 Data," February 2018.

[11] LBMPs will also rise when flexible hydropower or storage resources are on the margin since their opportunity costs will reflect the carbon effect on LBMPs.

An alternative considered was to change the offer structure and require suppliers to explicitly submit the emission rates or carbon charges associated with each existing offer component (*i.e.*, startup, no load, and incremental curves). The NYISO would add the associated costs to the traditional energy offer curves and conduct its dispatch/pricing optimization as usual. The NYISO rejected this alternative approach, as it would require substantial changes to the NYISO's market management software and would likely be burdensome for suppliers, without clear benefits in terms of accuracy and transparency.

Application of the Carbon Price to External Transactions

Proposal

Applying a carbon charge to only internal resources would make them less competitive compared to external resources. Imports would increase, potentially up to the transmission limit, and exports would decrease. Production would shift to resources outside of New York that would not otherwise generate—resources that are costlier and likely higher-emitting. Such distortions would undermine the state's energy, environmental and economic objectives.

To avoid creating such distortions, this Straw Proposal applies carbon charges to external transactions such that they compete with internal resources (and each other) on a status quo basis, as if the NYISO was not applying a carbon charge to internal suppliers. Imports would earn the LBMP without the carbon effect, at the relevant border; similarly, exports would buy energy at the LBMP without the carbon effect.[12] This would apply to all external transactions, with no unit-specific or portfolio-specific exceptions for existing or new clean energy resources.

To implement this approach in its existing market systems, the NYISO would treat imports and exports similar to today (with imported energy being paid the full LBMP and exports buying energy at the full LBMP), but then apply a carbon charge to imports and a credit to exports. For internal and external resources to continue to compete as they do currently (where, on net, external transactions experience only the non-carbon LBMP), the NYISO's carbon charges on imports and credits to exports would have to reflect the carbon effect on LBMPs at each border. The same values would apply to both imports and exports at the same interface over the same time interval.

Market participants would have to know the applicable charges/credits at each interface in advance of the day-ahead (DA) and real-time (RT) offer submission deadlines. This would allow them to incorporate the charges/credits into their offers/bids and compete with internal resources as intended. Since their

[12] And wheel-through transactions would pass through without being subjected to carbon charges other than the difference between entry and exit points (as they are already assessed congestion and marginal losses today). They would face the equivalent of an import transaction at the entry point plus an export transaction at the exit point.

offers/bids include an estimated carbon adder in $/MWh intended to reflect the marginal internal resources setting the prices (*i.e.*, the local carbon effect on the LBMP), they are competing as if there were no carbon charges.

The NYISO would calculate and post the applicable charges/credits in advance using a reasonable forecast of the carbon effect on the LBMP for each interface and time interval. The NYISO would have to develop a forecast methodology for setting the carbon charges/credits and test candidate approaches against historical data.[13] For example, one could test whether the corresponding hour of the prior day provides a good forecast for each hour the following day, versus more sophisticated alternatives.

Rationale and Alternatives Considered

This approach is a simple and transparent way to avoid the distortions described above, which would result from imposing a carbon charge on internal resources but not on external transactions. An alternative approach could be designed that would foster competition based on both carbon content (New York State's view of carbon externalities) and traditional costs, and thus optimize transactions to best serve New York's energy, environmental and economic goals. However, such approaches would be substantially more complicated and would risk creating unintended distortions. These concerns are discussed below.

An alternative approach that was considered would charge/credit external transactions based on the marginal emissions rate of the source/destination markets.[14] However, distortions could arise if the external emissions rates do not accurately reflect the actual marginal emissions consequences of transactions. Of particular concern would be that the marginal emissions consequences of imports from Ontario and Quebec could be much higher than any assessment of their fleets might suggest. Both provinces, especially Quebec, have very low average emissions. Yet their non-emitting resources are primarily energy-limited hydropower and wind (and baseload nuclear in Ontario), and thus increasing imports into the NYISO would likely require reducing their exports to other markets such as New England and MISO. This in turn may require additional fossil generation to back-fill the reduced imports into those markets. In such cases, the real marginal emissions associated with increased imports to the NYISO are not the emissions of the clean energy resource but those of incremental fossil generation in the neighboring market. Thus, assigning Ontario and Quebec a low emissions rate could result in just the kind of leakage that border charges are supposed to prevent. New York customers would have to pay a premium for those imports and might question the value of the price

[13] There is no historical data on the carbon effect of LBMPs, but NYISO would generate such data ex-post using the following real-time data it already has: (1) interval-level data on marginal units and fuel compositions; (2) the average emissions rate of the marginal unit for the fuel consumed; (3) whether the unit would pay the Gross or Net SCC; and (4) the shift factors over binding constraints, from the marginal units to each interface. When the marginal unit is pondage hydro or storage, NYISO can account for their opportunity cost and fossil substitutability by replacing them with the last fossil unit in the stack. Note that external transactions themselves are not marginal in real-time since they participate as fixed schedules in real-time.

[14] Ontario, Quebec, and California have taken this approach (although Ontario and California do not credit exports). For example, Ontario charges imports based on an annual study of the average marginal emissions rates in each source market for on-peak and off-peak hours. See: Ontario Ministry of Energy, Default Emission Factors for 2018 for Ontario's Cap & Trade Program, December 15, 2017. Posted at: http://www.energy.gov.on.ca/en/ontarios-electricity-system/climate-change/default-emission-factors-for-2018-for-ontarios-cap-trade-program/

signal that provides. Approaches that are more complex could be impracticable since the actual marginal emissions consequences of transactions will depend on many unobservable factors.

The patchwork of carbon pricing regimes in the neighboring markets further complicates the application of market-specific carbon charges: Ontario and Quebec participate in the Western Climate Initiative (WCI); ISO-NE states are all part of RGGI; and the states in PJM adjacent to the NYISO do not currently have any carbon pricing. Even within the WCI jurisdictions, Quebec and Ontario treat carbon charges on exports differently, which would require the NYISO to use separate approaches for setting the charges for each market. This would introduce additional complexity to these imports without the assurance of improved market dynamics, for the reasons just described.

Allocation of the Carbon Charge Residuals to Loads

Proposal

Load Serving Entities (LSEs) would continue to pay the full LBMP, including the effect of the carbon charge on LBMP, but they would be allocated the carbon charge residuals collected from suppliers through a cost levelizing allocation. The methodology would compensate for zonal differences in the carbon component of the LBMP. Carbon charge residuals would be allocated to customers in two steps: the NYISO would allocate all carbon residuals to LSEs, and then LSEs would allocate their portion of the residuals to customers.

For the first step, the NYISO would allocate residuals to LSEs with the highest carbon effect on LBMPs until the net cost of carbon pricing is generally equalized across all LSEs.[15] The NYISO would calculate the carbon component of each Load Zone LBMPs in each interval to determine the allocation factor for each Load Zone.

For the second step, LSE allocation to customers would be under PSC jurisdiction pursuant to the appropriate regulatory process, the details of which are outside the scope of this Straw Proposal.

[15] Differences would only be completely equalized if the total size of the carbon charge residuals exceeds the sum of absolute differences between LSE costs and NYCA average costs.

Rationale and Alternatives Considered

Any allocation mechanism should be evaluated against at least two design objectives:

- **Economic Efficiency**. LSEs in zones with higher carbon effects on LBMPs would still pay more on net than other LSEs, providing a stronger price signal to reduce consumption where marginal emissions rates are highest.
- **Equity of Cost Burden**. More of the residuals would be allocated to the customers who bear a greater cost of carbon pricing, thus reducing (but not eliminating) differences among LSEs in the net cost they face from carbon pricing.

The proposed carbon charge impact levelizing approach (Levelizing Allocation) prioritizes equity of cost burden: more of the residuals would be allocated to the customers who bear a greater cost of carbon pricing, thus reducing differences among LSEs in the net cost they face from carbon pricing. This could be considered more equitable as it likely results in all LSEs paying the same net cost of carbon pricing. However, by fully equalizing the net cost of carbon pricing across all LSEs, this approach would eliminate the differential price signal to reduce consumption (and emissions) more in zones with higher marginal emission rates.

An alternative approach that was considered would return carbon charge residuals to all LSEs on a load-ratio share basis (Load-Ratio Allocation).[16] As compared to the proposed approach, this would provide LSEs with a price signal more reflective of the carbon implications of their consumption. However, it could create equity concerns by causing greater differences in the net cost of carbon pricing across LSEs.

A third approach that was considered would return carbon charge residuals to all LSEs based on the proportional effect carbon prices have on their gross payments for energy (*i.e.*, the product of the carbon effect on applicable zonal LBMPs and their MWh of load) (Proportional Allocation). This approach would return more revenues to LSEs that face higher $/MWh cost impacts, but would not go so far as levelizing these cost impacts. This approach provides some balance between two competing objectives *economic efficiency* and *equity of cost burden*, as this approach would maintain some of the differential price signal to reduce consumption (and emissions) more in zones with higher marginal emission rates. To determine the proportional allocation of the carbon residuals, the NYISO would calculate the carbon effect on LBMP for each Load Zone in each real-time interval.[17]

[16] The NYISO would calculate each LSE's carbon charge residuals as total residuals multiplied by the LSE's load divided by total NYCA load.

[17] As noted in footnote 13 above, the NYISO would generate such data ex-post using the real-time data it already has.

Changes to Other NYISO Markets and Planning Processes

The NYISO capacity market and transmission planning processes will be impacted by the addition of carbon pricing into the energy market to the extent that the carbon charges result in different outcomes in terms of system dispatch and supplier net energy and ancillary services (E&AS) revenues. Most changes will automatically flow through the existing capacity market and transmission planning processes, but there are several changes that will be necessary to account for the changes in the energy market.

Installed Capacity Market

In the Installed Capacity Market, suppliers will choose how to account for any increase/decrease in their expected net E&AS revenues when deciding whether/how to offer into the capacity market. The NYISO will have to adjust the demand curve to the extent that the charges impact the net E&AS revenues for the combustion turbine (CT) reference technology that is used to calculate the demand curve Reference Price. The NYISO calculates the Reference Price based on the gross cost of new entry (CONE) minus the net E&AS revenues for the reference technology.

Since the 2016 Demand Curve Reset, the NYISO has been estimating the net E&AS revenues for the reference technology based on a historical simulation using the electricity, gas, and emissions prices from the previous three years. Historical simulations do not immediately incorporate new changes to the market. If this approach is not modified, for the first three years following the introduction of the carbon charges, the historical simulations would not yet account for the impact of the carbon charges on the net E&AS revenues of the CT reference technology. This could result in under-stating (or over-stating) the E&AS offset and thus over-procuring (or under-procuring) capacity. The effect is not likely to be large, given CT's limited run hours and marginality when running. Nevertheless, the NYISO would direct the Demand Curve Reset Consultant to assess whether an adjustment is necessary.

Transmission Planning

The NYISO regularly performs economic analyses of new transmission facilities in its Congestion Analysis and Resource Integration (CARIS) studies and as necessary for its Public Policy Transmission Needs (PPTN) planning processes. The economic analyses include production cost simulations that model the NYISO and regional power system under future market conditions in GE-MAPS.

These studies already account for the RGGI price and can similarly incorporate the higher carbon charges on all internal suppliers. With a carbon charge in place, the NYISO would adjust the CARIS planning process and any production cost modeling used in the public policy planning to include the applicable carbon price (gross or net as appropriate) set by PSC. The NYISO would also develop the necessary assumptions to model import charges and export credits properly that reflect the selected approach to account for external transactions.

Glossary of Terms

Carbon Price: The dollar per ton ($/ton) price the NYISO charges suppliers for their carbon emissions.

Carbon Charge: For internal suppliers, the total dollar amount charged for their emissions. For importers, the total dollar amount charged such that they compete on a status quo basis as if the NYISO was not applying a carbon charge to internal suppliers.

Carbon Credit: The total dollar amount paid to exporters such that they compete with external resources on a status quo basis, as if the NYISO was not applying a carbon charge to internal suppliers.

Carbon Adder: The additional costs in dollars per MWh ($/MWh) that suppliers include in their energy market offers due to the carbon charges.

Carbon Effect on LBMPs: The LBMP increase in dollars per MWh ($/MWh) due to the carbon adder of the marginal unit for each time interval and location.

Carbon Charge Residuals: The total dollar amount of carbon charges collected by the NYISO from suppliers.

Straw Proposal Summary Table

Design Topic	Proposed Approach
Setting the Gross Social Cost of Carbon	The New York Public Service Commission would set the Gross Social Cost of Carbon pursuant to the appropriate regulatory process
Application of Carbon Price to Internal Suppliers	**Approach:** All internal suppliers would be subject to carbon charges equal to the product of their point-of-production carbon emissions and the applicable per-unit carbon price **Emissions:** Internal suppliers, including self-scheduled resources, would report emissions of their supply fleet ▪ Tier 1 resources under the Clean Energy Standard are assumed to have zero emissions ▪ Cogeneration resources would be charged based on the portion of their emissions associated with electrical generation ▪ Behind-the-meter generation resources would be charged for emissions associated with net injections to the grid **Carbon Price:** The NYISO would determine the carbon price (in $/ton) depending on whether internal physical suppliers are covered by RGGI ▪ Suppliers covered by RGGI would be charged a carbon price equal to the Gross SCC minus the most recently posted quarterly carbon price ▪ Suppliers not covered by RGGI would be charged a carbon price equal to the Gross SCC **Market Operations:** ▪ Suppliers would be expected to embed the carbon charge into their energy offers ▪ Suppliers would continue to receive the full LBMP and will be debited their carbon charges during settlement ▪ Differences between self-reported emissions and actual emissions would be corrected via the true-up settlements process
Application of Carbon Price to External Transactions	**Approach:** ▪ Imports and exports would compete with internal resources on a status quo basis, as if there were no incremental carbon charge applied within the NYISO ▪ No unit-specific or portfolio-specific exceptions **Market Operations:** ▪ Transactions would see the full LBMP but imports would be debited and exports would be credited a carbon charge that reflects the expected carbon effect on the LBMP ▪ The NYISO would forecast, set, and publish applicable carbon charges and credits (in $/MWh) for each interface prior to day-ahead and real-time offer submission deadlines ▪ The NYISO would develop a methodology to forecast the carbon effect on LBMPs based on a study of historical data
Allocation of Carbon Charge Residuals to Loads	▪ Wholesale load would continue to pay the full LBMP, but will be allocated a portion of the carbon charge residuals ▪ Allocation by Load Serving Entities to customers would be under PSC jurisdiction pursuant to the appropriate regulatory process
Changes to Other NYISO Markets and Planning Processes	**Capacity Market:** ▪ The NYISO would direct the Demand Curve Reset Consultant to consider the effects of carbon pricing on the net cost of new entry of the proxy unit **Transmission Planning:** ▪ The NYISO would adjust the CARIS and public policy planning processes to account for the effects of carbon prices