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CARBON PRICING IN NEW YORK ISO MARKETS: Federal and State Issues

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EXECUTIVE SUMMARY

New York’s Clean Energy Standard (“CES”), adopted in August 2016, aims to steer the state’s electricity sector away from carbon-intensive generation sources. It supports low-carbon alternatives by requiring retail electricity suppliers to purchase credits, the proceeds from which are paid to renewable and nuclear generators. Recognizing that this will affect the operation of wholesale electricity markets, New York’s electric transmission grid operator (the “New York Independent System Operator” or “NYISO”) has commenced a review to assess possible means of incorporating the cost of carbon emissions into market prices. This would be a departure from the norm insofar as the cost of emissions is not directly valued in wholesale electricity markets. In another respect, however, NYISO’s review is not unusual: three of the six other wholesale electric grid operators in the U.S. are considering how best to handle greenhouse gas (“GHG”) emissions pricing,¹ and the Federal Energy Regulatory Commission (“FERC”) has called for a technical conference to address issues arising from state-level policies that address emissions directly and indirectly.²

NYISO is currently developing a white paper which will analyze the pros and cons of various carbon pricing schemes. To inform NYISO’s analysis, this paper explores two approaches to carbon pricing: the first would involve NYISO adopting a carbon price of its own initiative with a view to improving the operation of wholesale electricity markets (“Approach 1”), while the second would involve adoption of a carbon price designed to reflect and harmonize state-level policies aimed at reducing electricity sector emissions (“Approach 2”). Under either approach, NYISO would adopt a per megawatt hour carbon price and use it to establish a fee for each generating unit, consistent with its emissions profile. This fee would be added to the prices generators bid into the wholesale electricity market and those adjusted prices used by NYISO to

¹ See ISO New England, NEPOOL 2016 IMAPP Proposals Observations, Issues, and Next Steps 2 (Jan. 2017), <https://perma.cc/C238-FZQN>; California ISO, Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw Proposal (Dec. 1, 2016), <https://perma.cc/D5E3-UGHG>; Stu Bresler, PJM, *Potential Alternative Approach to Expanding the Minimum Offer Price Rule to Existing Resources*, GRID 20/20 (Aug. 11, 2016), <https://perma.cc/M7YG-7BWW>.

² Rebecca Kern, *How Markets Adapt to State Energy Plans Topic of FERC Meeting*, BLOOMBERGBNA, Feb. 14, 2015, <http://bit.ly/2kTMSHq>.

determine the dispatch order. The result would likely be a re-ordering of dispatch, with high-emitting generators dispatched (and paid) less frequently, and cleaner alternatives more frequently.

Our proposal, while conceptually simple, is likely to be difficult to implement. Key issues that must be addressed before its adoption and implementation include:

- **Design:** NYISO could derive a carbon price from the social cost of carbon (“SCC”). Developed using technical models with significant public input, the SCC is a robust metric that is consistent with the carbon prices currently used elsewhere in the electricity sector. Despite this, however, its use may be opposed by some industry and other groups on the grounds that it reflects the economy-wide costs of climate change, not just costs imposed on electric grid operations. .
- **Ensuring fairness for generators:** Whether NYISO derives its carbon price from the SCC or another touchstone, care must be taken to ensure that it does not duplicate other carbon pricing schemes. Some generators bidding into NYISO markets are already subject to carbon pricing through the Regional Greenhouse Gas Initiative (“RGGI”), a cap-and-trade program, under which large fossil fuel generators are required to purchase emissions allowances at prices set by auction. To ensure that those generators are not required to pay twice for the same emissions, the RGGI auction price should be deducted from the carbon fee NYISO would add to their bids. The carbon fee may also need to be adjusted to account for the value of zero-emission credits paid to nuclear generators under tier 3 of the CES.
- **Mitigating consumer impacts:** Adoption of a carbon pricing scheme by NYISO would likely lead to an increase in wholesale electricity prices, at least in the short term. To offset this increase, revenues generated through carbon pricing should be refunded to retail electricity suppliers in an equitable manner, not tied to their specific purchases. We recommend that New York direct its retail suppliers to pass refunds through to their customers. This will be important to mitigate end-customer bill impacts.
- **Providing legal justification:** Any NYISO carbon pricing scheme would be subject to review by FERC. The Federal Power Act confers broad authority on FERC to shape wholesale electricity markets to ensure that they produce just and reasonable rates. This paper presents arguments supporting the view that incorporating a carbon price into

wholesale electricity rates – under either Approach 1 or Approach 2 - would be just and reasonable. We acknowledge, however, that Approach 1 would push the boundaries of past market regulation, though in ways that are consistent with the law and with FERC practice. Approach 2 would fit more comfortably within the existing boundaries of FERC’s authority to strike a balance between respecting state-level public policy and ensuring the smooth operation of wholesale markets.

▪ **Arguments supporting Approach 1:**

- **Enhancing competition in wholesale energy markets:** FERC takes the view that carefully designed competitive wholesale markets will produce just and reasonable rates. The current failure to price carbon undermines the competitiveness of markets and, more specifically, low-carbon generators’ participation in those markets. Adopting a carbon price, based on the SCC, would level the playing field for all market participants and would be wholly consistent with FERC’s past efforts to improve the functioning of markets.
- **Ensuring proper wholesale price formation:** FERC has emphasized that, to provide the correct incentives for investment, wholesale electricity rates must reflect the cost of generation. Currently, however, market-based rates do not reflect the cost of carbon dioxide emissions and associated climate change. Climate change will impair generation and transmission facility efficiency, undermining reliability and imposing costs on market participants which must be reflected in rates so as to provide correct incentives for investment in new facilities. As the SCC would exceed costs to market participants, its use could not be justified solely by this argument. Considered in isolation, this argument would justify a lower carbon price, based on costs to market participants.

▪ **Arguments supporting Approach 2:**

- **Align wholesale markets with state-level public policy for the short- and long-term:** New York has adopted several policies in service to its goal of decarbonizing the electricity sector, including three that impose disparate prices on a patchwork of generators. It has also articulated long-term targets for emissions reductions that will not be achieved without the adoption of further specific policy measures in the

future. A carbon pricing scheme that rationalizes existing public policy and anticipates foreseeable changes to that public policy would respect state authority while also ensuring that wholesale markets operate efficiently and send accurate signals to market participants and investors. Notably, such a scheme would also reinforce FERC's goals for improving transmission planning, in part by encouraging greater attention to non-transmission alternatives. It should be noted that the facts underlying this argument would also support Approach 1.

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LIST OF ACRONYMS

CAISO	California Independent System Operator
CARIS	Congestion Assessment and Resource Integration Study
CES	Clean Energy Standard
CRP	Comprehensive Reliability Plan
dCC	Dormant Commerce Clause
DEC	Department of Environmental Conservation
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
GHG	Greenhouse gas
ICAP	Installed capacity market
IMAPP	Integrating Markets and Public Policy
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
LCOE	Levelized cost of electricity
LMP	Locational marginal pricing
LSE	Load serving entity
LTP	Local Transmission Plans
LTPP	Local Transmission Planning Process
MST	Market Services Tariff
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt hour
NEPOOL	New England Power Pool
NYCA	New York Control Area

NYGATS	New York Generator Attribute Tracking System
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York Energy Research and Development Authority
OATT	Open Access Transmission Tariff
PURPA	Public Utilities Regulatory Policies Act
PPTPP	Public Policy Transmission Planning Process
REC	Renewable Energy Credit
RGGI	Regional Greenhouse Gas Initiative
RNA	Reliability Needs Assessment
RPP	Reliability Planning Process
RTO	Regional Transmission Operator
SCC	Social Cost of Carbon
SPP	Southwest Power Pool
ZEC	Zero Emission Credit

1. INTRODUCTION

As part of its ongoing efforts to combat climate change, New York has committed to reducing statewide greenhouse gas (“GHG”) emissions by forty-percent below 1990 levels by 2030 (the “40 by 30 goal”). The bulk of emissions reductions are expected to come from the electricity sector, with the state aiming to secure fifty percent of its electricity needs from zero-emitting renewable generators. Consistent with this goal, the state’s Clean Energy Standard (“CES”) requires retail electricity suppliers (“Load Serving Entities” or “LSEs”) to purchase Renewable Energy Credits (“RECs”), the proceeds from which will be paid to renewable generators. The CES also requires LSEs to obtain Zero-Emission Credits (“ZECs”), which compensate nuclear generators for their zero-emission attributes.

Prompted in part by adoption of the CES, the New York Independent System Operator (“NYISO”), a non-profit corporation which oversees electricity transmission and wholesale sales in New York, has commenced a review into whether and how policies that assign values to generators’ zero-emission attributes and to GHG emissions should be priced in wholesale electricity markets. During the first quarter of 2017, NYISO will release a white paper, analyzing various emissions pricing schemes. This paper is intended to inform NYISO’s analysis and, to that end, explores two approaches to emissions pricing in wholesale markets.

Wholesale electricity markets have generally treated GHG emissions as a wholly exogenous externality of generation, to be addressed—if they are to be addressed at all—through environmental policy tools such as pollution control laws or temporary emerging-market subsidies for the nascent renewables industry.³ In our view, however, the Federal Energy Regulatory Commission (“FERC”) has authority to approve a NYISO tariff that prices-in emissions insofar as it (a) merely makes way for or harmonizes public policy at the state level, or (b) can be shown to improve the functioning of wholesale markets to ensure just and reasonable rates. These two legal

³ See *Grand Council of the Crees v. FERC*, 198 F.3d 950, 956 (D.C. Cir. 2000) (“potential siting, health, safety, environmental or archeological problems are beyond the Commission’s authority to consider under sections 205 and 206 of the Federal Power Act”).

paths to emissions pricing are not mutually exclusive, but they are distinct and would have implications for the approach taken by NYISO.

Both paths are rooted in the authority conferred by the Federal Power Act (“FPA”), which empowers FERC to shape wholesale electricity markets and steer transmission planning to ensure that the bulk power system delivers reliable electricity services for just and reasonable rates. Although FERC has not previously relied on this authority to price GHG emissions, neither the FPA’s capacious language nor the judicial decisions that have interpreted it prevent such a step. Indeed, as explained below, we read existing authority as all but commanding that wholesale markets be reconfigured to better account for the costs of emissions.

The authors recognize that one of our proposed paths to pricing emissions—which would see NYISO adopting an emissions price of its own initiative with a view to improving the operation of wholesale electricity markets—would push the boundaries of what has to date been considered the limit of FERC’s authority. Many view climate change as an environmental externality whose attendant costs lay beyond the scope of what ought to inform FERC’s assessment of wholesale rates’ justness and reasonableness.⁴ We argue, however, that climate change and the GHG emissions that cause it materially affect the wholesale energy market. The carbon pricing scheme we propose would ensure those effects are properly accounted for in market prices. The proposal would, like several other recent orders, enhance competition and improve price formation. It would also support effective planning.

The fact that the FPA does not expressly authorize emissions pricing in wholesale markets is not fatal. FERC has, in the past, taken steps not contemplated in the FPA. The establishment of wholesale markets is a good example. At the time the FPA was enacted, electricity services were provided by vertically integrated utilities. Markets evolved gradually over time, as a result of

⁴ See Todd S. Aagard, *Energy-Environment Policy Alignments*, 90 WASH. L. REV. 1517, 1546 (2015) (“Broadening FERC’s authority to encompass externalities and other market failures . . . would fundamentally re-orient the agency in ways that would likely generate significant opposition from both inside and outside the agency—and perhaps from courts as well.”); John S. Moot, *Subsidies, Climate Change, Electric Markets and the FERC*, 35 ENERGY L. J. 345 (2014) (stating without explanation that ignoring generators’ GHG emissions is “fuel-neutral”); Eric Filipink, *Serving the “Public Interest” — Traditional vs Expansive Utility Regulation*, NRRI Rep. No. 10-02 (Dec. 30, 2009), <https://perma.cc/UMU7-WKXN> (discussing aspects of issue in retail market context).

various FERC actions, beginning with the adoption of Order 888 in 1996. That order laid the groundwork for competitive energy markets by requiring utilities to provide “open access” transmission services to unaffiliated generators. The order is widely considered a response to the Energy Policy Act of 1992, which authorized FERC to order individual utilities to provide transmission services on a case-by-case basis. Crucially, however, it is the FPA and not the 1992 Act that provides the legal basis for FERC’s creation of wholesale markets.⁵ Indeed, FERC went beyond what the 1992 Act required after recognizing that the process it prescribed would be too costly and time-consuming to ensure just and reasonable rates.⁶

This paper proceeds as follows: Parts 2, 3, and 4 provide background on electricity infrastructure, wholesale markets, and carbon pricing respectively—topics that are likely familiar for some readers. Part 5 briefly discusses New York State’s current carbon pricing programs, which are designed to operate outside the wholesale electricity market. Part 6 explores mechanisms NYISO could employ to implement a carbon price in the wholesale market. And Part 7 offers arguments that could be presented in support of a NYISO carbon price proposal to FERC.

2. ELECTRICITY MARKETS 101

Electricity services were historically provided by vertically-integrated utilities, which owned generating units, as well as transmission and distribution infrastructure. Each utility operated as a regulated monopoly, selling electricity within an exclusive service territory. Regulation of electricity sales was—and still is—shared between the federal government and the states. At the federal level, FERC is authorized to regulate the transmission and wholesale sale of electricity in interstate commerce under the FPA.⁷ The FPA defines wholesale sales as sales of

⁵ *New York v. FERC*, 535 U.S. 1, 11 (2002) (“Rather than grounding its legal authority [to issue Order 888] in Congress’ more recent electricity legislation, FERC cited §§ 205-206 of the 1935 FPA—the provisions concerning FERC’s power to remedy unduly discriminatory practices—as providing the authority for its rulemaking. See 16 U.S.C. §§ 824d-824e.”).

⁶ *Id.*

⁷ 16 U.S.C. § 824(a) - (b) (providing for federal regulation of the “transmission of electric energy in interstate commerce and . . . the sale of electric energy at wholesale in interstate commerce”).

electricity “to any person for resale.”⁸ Those sales are considered to occur in “interstate commerce” whenever electricity is transmitted via an *interstate* grid.⁹ Where transmission occurs via an *intrastate* grid, the sale is not subject to regulation by FERC, but may be regulated by the state in which it occurs. The states also regulate retail electricity sales.

All electricity sold in the contiguous U.S. is transmitted via three synchronous grids, namely:

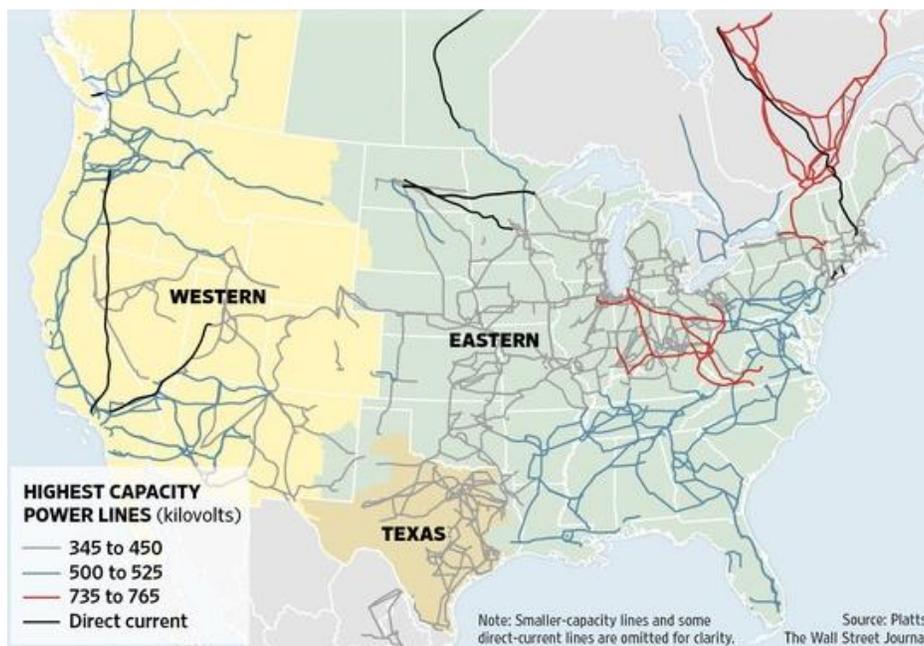
1. the Eastern Interconnection, which extends from central Canada south to Florida and includes all U.S. territory east of the Great Plains, except parts of Texas and Maine;
2. the Western Interconnection, which extends from western Canada south to Mexico and includes all U.S. territory west of the Great Plains; and
3. the Texas Interconnection, which covers most of Texas.

As the Eastern and Western Interconnections cross state borders, electricity transmission thereon is considered to occur in interstate commerce, making it subject to regulation by FERC. FERC’s regulatory duties include ensuring wholesale electricity rates are just and reasonable and not unduly discriminatory or preferential, and that the bulk power system operates reliably.¹⁰

⁸ *Id.* § 824(d).

⁹ Fed. Power Comm’n v. Florida Power & Light Co., 404 U.S. 452 (1972).

¹⁰ 16 U.S.C. §§ 842d(a) (requiring “all rates and charges made, demanded, or received by any public utility for . . . [the] sale of electric energy subject to the jurisdiction of the Commission . . . shall be just and reasonable and any such rate or charge that is not just and reasonable is hereby declared to be unlawful”), 842(b) (providing that “[n]o public utility shall, with respect to any . . . sale subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage”), 842d(e) (authorizing FERC to conduct “a hearing concerning the lawfulness of” any rate or charge), 824e(a) (requiring FERC, when it determines that a rate or change “is unjust, unreasonable, unduly discriminatory or preferential . . . [to] determine the just and reasonable rate” or charge), 824o (providing FERC with authority to enforce “reliability standards” via “Electric Reliability Organizations” certified by FERC).

Figure 1: Transmission Interconnections in the Continental U.S.¹¹

For most of the 20th century, FERC regulated wholesale electricity rates exclusively on a cost of service basis, under which utilities were permitted to recover the prudent expenses they incurred in providing services, plus a reasonable return on capital. Recently, however, FERC has increasingly relied on markets to set rates. This shift began in the late 1980s, with FERC issuing a series of market-based rate authorizations, which exempt utilities and other suppliers from cost of service regulation, allowing them to sell electricity at market-based rates.

2.1 The Evolution of Wholesale Electricity Markets

Historically, most vertically-integrated utilities produced electricity through self-supply (i.e., by constructing their own generating units). Utilities also entered into long-term bilateral contracts to purchase electricity from independently owned generating units. Such bilateral contracts are still widely used to procure electricity today; procurement also occurs through wholesale spot markets in some areas.

¹¹ See Energy & Policy Institute, *How to Secure the Grid and Save Ratepayers Money*, <https://perma.cc/C3PP-FY77> (last visited Dec. 30, 2016).

The origins of wholesale markets can be traced back to the energy crisis of the 1970s. In response to the crisis, Congress enacted the Public Utilities Regulatory Policies Act of 1978 (“PURPA”)¹² to incentivize alternative means of electricity generation, among other things. PURPA led to the construction of hundreds of merchant generating facilities, the owners of which demanded access to the utility-owned transmission grid, to transport their electricity to retailers and/or consumers. In response to those demands, Congress enacted the Energy Policy Act of 1992, which authorized FERC to order individual utilities to provide transmission services to merchant generators. After issuing twelve such orders in twelve separate proceedings, FERC determined that this case-by-case approach was too costly and time consuming to provide an adequate remedy for undue discrimination.¹³ Thus, in 1996, it issued Orders 888¹⁴ and 889 requiring all utilities to provide “open access” transmission services.¹⁵

Orders 888 and 889 aimed to, among other things, enhance merchant generators’ access to electric utilities’ transmission infrastructure.¹⁶ Utilities were required to unbundle electricity transmission from sales¹⁷ and act as common carriers, providing transmission services to both affiliated and non-affiliated companies on a non-discriminatory basis.¹⁸ FERC suggested that utilities could “ensure fair and non-discriminatory access to transmission services” by forming independent system operators (“ISOs”) to manage the transmission grid.¹⁹ Subsequently, in Order 2000, FERC encouraged utilities to place their transmission facilities under the management of an ISO or Regional Transmission Operator (“RTO”).²⁰

¹² Pub. L. 95-617, 92 Stat. 3117 (Nov. 9, 1978) (codified as amended at 16 U.S.C. § 2601 et seq.).

¹³ For a discussion of this issue, see *New York*, 535 U.S. 9 (2002).

¹⁴ Order No. 888: Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, 75 FERC 61,080 (Apr. 24, 1996) [hereinafter Order 888].

¹⁵ Order No. 889: Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct, 75 FERC 61,078 (Apr. 24, 1996).

¹⁶ Order 888, *supra* note 14, at 1.

¹⁷ *Id.* at 57 – 61.

¹⁸ *Id.*

¹⁹ *Id.* at 280.

²⁰ Order No. 2000: Regional Transmission Organizations, 89 FERC 61,285 (Dec. 20, 1999) [hereinafter Order 2000].

ISO/RTOs are independent bodies which operate the transmission system in one or more states. Figure 2 below shows the ISO/RTOs currently operating in the U.S. Six of those ISO/RTOs – the California IOS (“CAISO”), Midcontinent ISO (“MISO”), New England ISO (“ISO-NE”), NYISO, PJM Interconnection (“PJM”), and Southwest Power Pool (“SPP”) – are regulated by FERC. FERC does not have regulatory authority over the Electric Reliability Council of Texas (“ERCOT”) as its transmission system “is located solely within the state of Texas and is not synchronously interconnected to the rest of the United States.”²¹

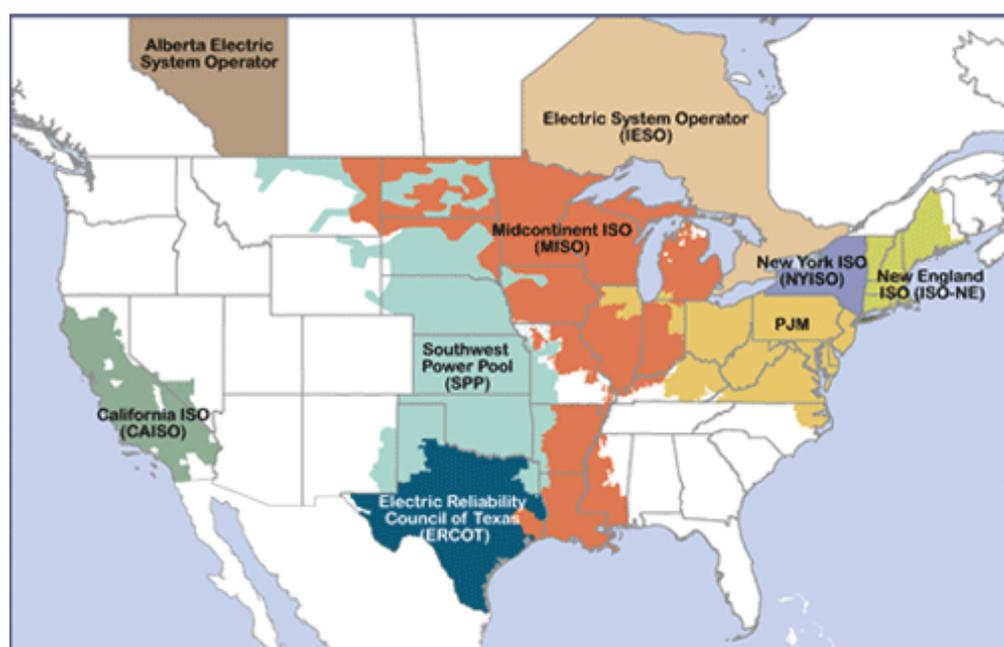


Figure 2: ISO/RTOs Operating in the U.S.

Each ISO/RTO is a non-profit or profit-neutral corporation that contracts with transmission facility owners (“Transmission Owners”) regarding transmission and wholesale market governance.²² In addition to those basic contracts, each ISO/RTO also adopts two tariffs, subject to

²¹ FERC, *ERCOT*, RTO/ISO, <https://perma.cc/UE82-FFE3> (last updated Nov. 17, 2015). ERCOT’s operations are overseen by the Public Utility Commission of Texas and the state legislature. See FERC, *Texas (ERCOT)*, ELECTRIC POWER MARKETS, <https://perma.cc/GB6D-6SGV> (last updated Mar. 10, 2016).

²² Amended and Restated Transmission Control Agreement among the California Independent Service Operator Corporation and Transmission Owners (Mar. 31, 1998), <https://perma.cc/JRQ6->

FERC review (ERCOT's excepted), that specify how the ISO/RTO is to oversee regional transmission facilities and markets; the Open Access Transmission Tariff ("OATT") governs the former, the Market Services Tariff ("MST") the latter.

2.2 Wholesale Electricity Market Operation

Each ISO/RTO operates two wholesale electricity or "energy" markets, namely:

1. a day-ahead market, in which participants commit to buy or sell electricity at various times over the next twenty four hours, based on forecast demand ("load"); and
2. a real-time market, in which participants buy and sell electricity to balance differences between the day ahead commitments and actual load and generation.²³

Wholesale energy markets are open to any entity that, after securing the necessary approvals, can generate electricity and deliver it to the grid. The principal suppliers in most markets are utilities with excess generating capacity, utility-affiliated competitive generators, and independent power producers.²⁴ The principal buyers in most markets are LSEs, which provide retail electricity services to residential, commercial, and industrial customers. LSEs participating in wholesale energy markets currently serve consumers accounting for two-thirds of national electricity load.²⁵

While the specific design of energy markets varies between ISO/RTOs, all use bid-based auctions to set prices. During the auction, generators submit bids indicating the price at which they are willing to supply electricity, based on their marginal costs.²⁶ Generators are dispatched based

2EJ5; ISO New England, Transmission Operating Agreements, <https://perma.cc/UVB4-HWFL>, (last visited Dec. 11, 2016)) (providing links to Transmission Operating Agreement, Rate Design and Funds Disbursement Agreement, Phase I/II Transmission Operating Agreement, Phase I/II HVDC transmission facility); Amended and Restated Operating Agreement of PJM Interconnection, LLC (July 14, 2011), <https://perma.cc/KX2K-2T8Y>.

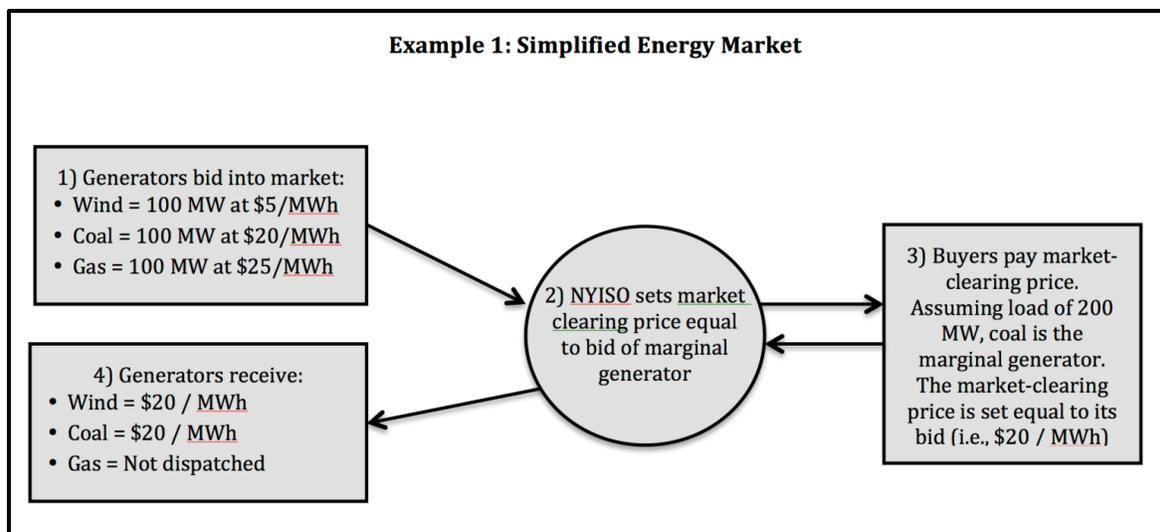
²³ FERC, SECURITY CONSTRAINED ECONOMIC DISPATCH: DEFINITION, PRACTICES, ISSUES, AND RECOMMENDATIONS 5-6 (2006), <https://perma.cc/8HW6-KKHC>.

²⁴ Another category of suppliers is demand response aggregators, being entities that enlist end-users to participate in demand response programs, whereby they agreed to curtail their electricity use at certain times, and sell the combined load reduction in wholesale energy markets.

²⁵ FERC, *Electricity Markets: National Overview*, <https://perma.cc/2X7R-S2RH> (last updated Feb. 29, 2016).

²⁶ Generators' bids typically reflect their variable costs of operation, including operations and maintenance costs, fuel costs, and emissions costs (e.g., the cost of acquiring emissions permits) (if

on their bids, from lowest to highest, until load is satisfied.²⁷ The bid of the last supplier dispatched (the “marginal generator”) determines the market-clearing price which is paid to all suppliers regardless of their bids (see Example 1).



Several ISO/RTOs also administer auctions for procuring capacity. In Order 2000, FERC determined that ISO/RTOs should be responsible for maintaining electric system reliability and must, among other things, ensure sufficient generating capacity is available to satisfy load.²⁸ To that end, ISO/RTOs may operate capacity markets in which owners of generating facilities are paid to have reserves²⁹ available in case they are needed in the future.³⁰ Capacity markets operate in a

any). SUSAN F. TIERNEY & PAUL J. HIBBARD, ANALYSIS GROUP, CARBON CONTROL AND COMPETITIVE WHOLESALE ELECTRICITY MARKETS: COMPLIANCE PATHS FOR EFFICIENT MARKET OUTCOMES 35 (2015), <https://perma.cc/F2Q7-WUFG>.

²⁷ An ISO / RTO may elect not to dispatch generators on the basis of cost if doing so would threaten the security of the electricity system. Thus, for example, an ISO / RTO may choose not to dispatch the least-cost generator if doing so would result in transmission congestion or other operational problems. This approach is known as “security constrained least-cost” dispatch. For a discussion of security constrained least cost dispatch, see FERC, *supra* note 23.

²⁸ Order 2000, *supra* note 20, at 315.

²⁹ The term “reserves” refers to generating capacity that is a currently unused but which is available to serve load. See generally Zhi Zhou et al., Argonne National Laboratory, Survey of U.S. Ancillary Services Markets (Jan. 2016), <https://perma.cc/HQ8N-4NBM> (indicating that “reserves are typically segmented into two categories, 1) Spinning or Synchronized Reserves that are

similar way to energy markets, with participants submitting bids that reflect the price at which they are willing to buy and sell capacity. The bids are then matched by the ISO/RTO to determine a clearing price, which is typically expressed per unit of capacity and paid to suppliers on a monthly basis. Whereas capacity prices are recovered through fixed monthly payments, electricity prices fluctuate hourly.

If there were no logistical impediments to the flow of electricity, a single price would apply throughout an ISO/RTO region for a given interval.³¹ However, because transmission congestion and/or other operational problems regularly impede electricity flows, some areas must rely on electricity priced above the region's lowest price.³² To account for differences in the cost of electricity used in different areas, ISO/RTOs price electricity using the locational marginal price ("LMP") at each of various nodes (i.e., locations) on the transmission system.³³

3. ELECTRICITY MARKETS IN NEW YORK

Electricity transmission and wholesale electricity sales in New York are managed by NYISO. In December 1999, NYISO took over management of the New York Control Area

provided by generation units that are actively generating and have the ability to increase or decrease their output, 2) Non-spinning or Non-synchronized Reserves that are provided by generation resources that are not actively generating, but are able to start up and provide generation within a specified timeframe. Operating reserves typically have response times on the order of ten to 30 minutes and can similarly be provided by supply-side resources that are capable of reducing their load.")

³⁰ Alternatively, an ISO / RTO may impose a "resource adequacy" obligations on load-serving entities, requiring them to self-supply capacity, either through construction of new capacity resources or by entering into bilateral arrangements to purchase capacity. See SUSAN F. TIERNEY & PAUL J. HIBBARD, ANALYSIS GROUP, CARBON CONTROL AND COMPETITIVE WHOLESALE ELECTRICITY MARKETS: COMPLIANCE PATHS FOR EFFICIENT MARKET OUTCOMES 36 (2015), <https://perma.cc/L46M-MLF7>.

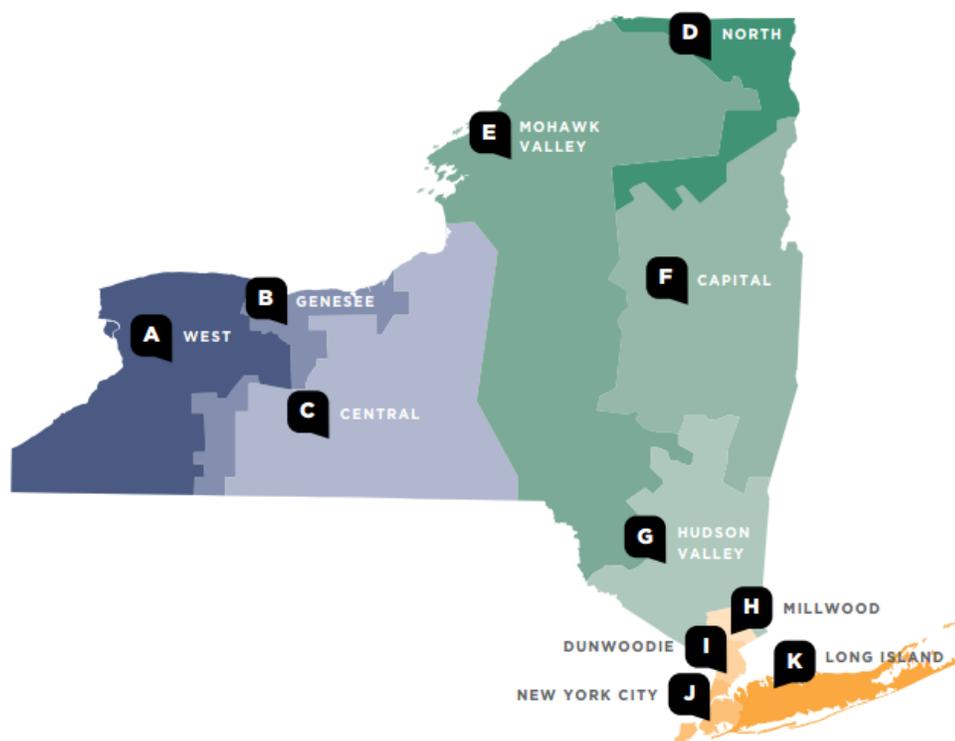
³¹ PJM INTERCONNECTION, LOCAL MARGINAL PRICING 1 (2016), <https://perma.cc/T9VQ-KD4K>.

³² *Id.*

³³ For a discussion of locational marginal pricing, see PJM Interconnection, *Locational Marginal Pricing*, BUYING & SELLING ELECTRICITY, <https://perma.cc/6BED-UX4C> (last visited Nov. 22, 2016); ISO-NE, *Locational Marginal Pricing*, FREQUENTLY ASKED QUESTIONS, <https://perma.cc/2FCU-ULAT> (last visited Nov. 22, 2016); NYISO, LOCAL MARGINAL PRICING: THE CORNERSTONE OF THE NYISO MARKET OPERATION, <https://perma.cc/FXR3-VJWL>.

(“NYCA”), which is coterminous with New York’s borders. NYISO divides the NYCA into 11 Zones (see Figure 3 below). Of those, the five “downstate” Zones (Long Island, New York City, Dunwoodie, Millwood, and the Lower Hudson Valley) account for about fifty-eight percent of the state’s load and sixty-five percent of its peak load, but generate only forty percent of its electricity.³⁴ This mismatch has made congestion between downstate and upstate zones³⁵—and downstate transmission adequacy more generally—a high-priority issue.³⁶ The addition of over 2,700 MW of transmission capacity since 2000 has not resolved the issue, not least because peak load continues to grow even as NYISO-wide load has flattened out.³⁷

Figure 3: NYISO Zones A through K



³⁴ NYISO, *POWER TRENDS: THE CHANGING ENERGY LANDSCAPE 2016*, at 2 (2016), <https://perma.cc/W3QB-9DZH> [hereinafter *POWER TRENDS*].

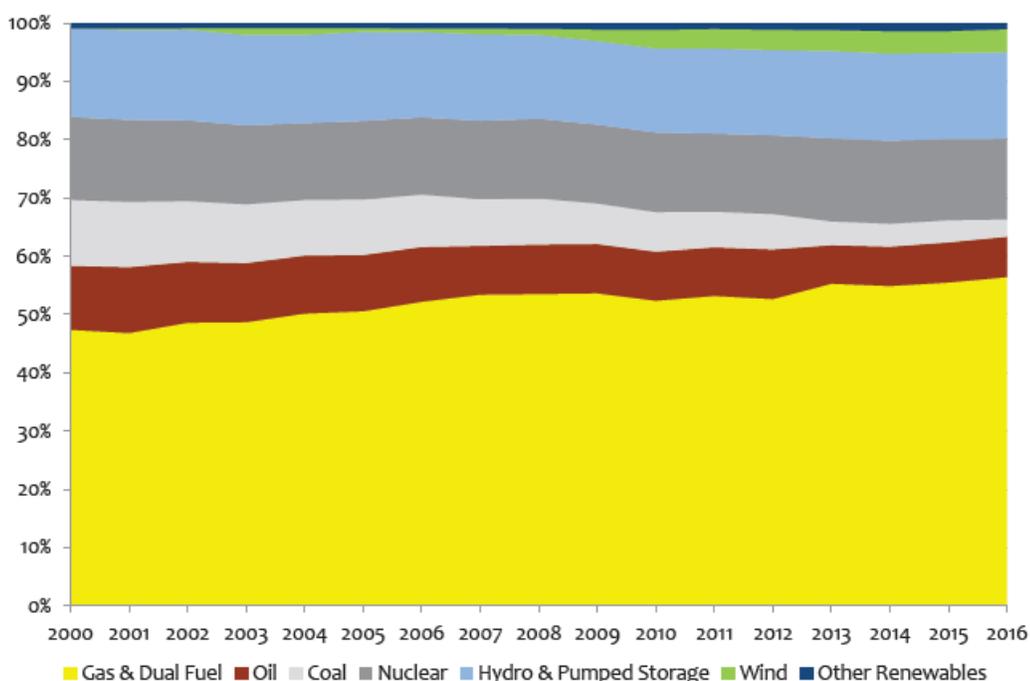
³⁵ B. Howard et al., *Current and near-term GHG emissions factors from electricity production for New York State and New York City*, 187 *APPLIED ENERGY* 255 (Feb. 2017), <https://perma.cc/FY5L-KXSW>.

³⁶ See David B. Patton et al., 2015 State of the Market Report for the New York ISO Markets 10 (May 2016), <http://bit.ly/2gzintb> (charting levels of inter-zone congestion and noting that the value of congestion--meaning costs resulting from it--were \$539 and \$700 for the day-ahead and real-time energy markets respectively).

³⁷ *POWER TRENDS*, *supra* note 34, at 9–10 fig.6.

The generation mix in NYISO has changed substantially over the last decade.³⁸ Since 2000, coal and oil have declined, natural gas and renewables have made up the difference, and nuclear and hydro have held steady (see Figure 4).³⁹ These changes have contributed to substantial reductions in regional emissions: annual sulfur dioxide emissions have dropped ninety-four percent and carbon dioxide emissions forty-two percent.⁴⁰

Figure 4: NYISO Generation Mix 2000 - 2016



3.1 NYISO Markets for Energy, Capacity, and Ancillary Services

Like other ISO/RTOs, NYISO manages markets that allocate energy, ancillary services, and capacity. The energy and ancillary services markets establish prices reflective of the value of energy at each locational node on the NYISO transmission network. The capacity markets establish

³⁸ NYISO, 2016 LOAD & CAPACITY DATA ("GOLD BOOK") (Apr. 2016), <https://perma.cc/W45L-JLDR>.

³⁹ POWER TRENDS, *supra* note 34, at 26 fig.20.

⁴⁰ *Id.* at 35–36.

prices reflective of expectations for how much existing and new capacity will be required to meet demand generally and at peak times.

NYISO's markets for energy assign location-specific prices in five-minute increments based on day-ahead and real-time auctions, as well as bilateral contracts between wholesalers and retailers. The day-ahead market schedules about ninety-four percent of the energy that is delivered in NYISO; the real-time market schedules the remainder and thereby serves as a corrective for day-ahead arrangements that over- or under-estimate load.⁴¹ Auctions account for about sixty percent of NYISO's energy transactions; bilateral contracts account for the remaining forty percent.⁴²

NYISO's ancillary services markets assign prices to a group of operations that underpin reliability by filling in gaps left by the energy markets. NYISO provides some of those operations, some are provided by transmission customers and suppliers, and others are self-provided by NYISO market participants.⁴³ These operations, which draw on both physical equipment and human resources, include:

- voltage support, meaning maintenance of a voltage level that falls within both power quality requirements and transmission facilities' heat tolerances;⁴⁴
- regulation and frequency response, which involves minute-to-minute adjustments that balance out unexpected small changes in generation and load;⁴⁵
- energy imbalance, which is the term of art for allocations and settlements arrived at through the real-time market that correct for over- or under-estimates by day-ahead market participants and managers;⁴⁶
- operating reserves, which stand ready to provide backup electricity or demand response for ten- and thirty-minute intervals in case of a sudden large change in generation or load at a given nodal location;⁴⁷ and

⁴¹ Patton et al., *supra* note 36, at 36.

⁴² *Id.*

⁴³ NYISO, Ancillary Services Manual (Oct. 2016), <https://perma.cc/ENW4-ED26>.

⁴⁴ *Id.* at 3-1.

⁴⁵ *Id.* at 4-1.

⁴⁶ *Id.* at 5-1.

- black start capability, which is the ability of a generating unit to, after shut down due to a general blackout and without assistance from the grid, begin operating and delivering power to the grid.⁴⁸

Whereas NYISO's energy and ancillary services markets provide for electricity services in the short term, its installed capacity market ("ICAP") trades in options to access transmission, generation, and demand response resources at a date one to twelve months in the future.⁴⁹ NYISO's ICAP operates through a series of auctions.⁵⁰ In the Capability Period Auction or "strip auction," which occurs twice each year,⁵¹ buyers and sellers trade for one or more months of capacity. Subsequent Monthly Auctions, held at least 15 days before the next calendar month (called an "Obligation Procurement Period"), allocate capacity for any gaps left by the Capability Period Auction. Finally, Spot Market Auctions, held at least two days before each Obligation Procurement Period, resolve any remaining gaps. By assigning auction-derived prices to options to access particular resources, the ICAP signals when additional resources—whether located within the NYCA or other balancing areas—are foreseeably necessary to ensure reliability over the subsequent months.⁵²

⁴⁷ *Id.* at 6-1 to 6-2.

⁴⁸ *Id.* at 7-1.

⁴⁹ Patton et al., *supra* note 36, at 24; *see also* Written Statement of Emilie Nelson, VP, NYISO, Docket No. AD14-18-000, Joint Technical Conference on New York Markets & Infrastructure, at 1-5 (Nov. 3, 2014) (summarizing recent history of ICAP).

⁵⁰ NYISO, Installed Capacity Manual 5-1 to 5-5 (June 2016), <https://perma.cc/L9LH-HAGE>. The parameters for "reliability," which include reserve margins and other elements, are specified by the New York State Reliability Council. *See generally* New York State Reliability Council, Reliability Rules & Compliance Manual For Planning and Operating the New York State Power System; Version 38 (Sept. 2016), <https://perma.cc/8YVT-5MSG>.

⁵¹ Auctions must be held at least thirty days before each capability period. The summer capability period runs from May through October, while the winter period runs from November through April.

⁵² NYISO, *supra* note 50, at 2-1 to 2-2. The parameters for "reliability," which include reserve margins and other elements, are specified by the New York State Reliability Council. *See generally* New York State Reliability Council, *supra* note 50.

3.2 NYISO's approach to planning and tariff revision

Although NYISO's geographic boundaries align with those of New York, NYISO's physical integration in the Eastern Interconnection means that it trades energy and services in interstate commerce, making it subject to FERC's authority pursuant to the FPA.⁵³ As noted in Part 2 above, under the FPA, FERC is authorized to regulate interstate electricity transmission and wholesale sales.⁵⁴ FERC's regulatory authority extends to "any person who owns or operates facilities" used in those activities (defined as a "public utility").⁵⁵ As the operator of New York's transmission facilities, NYISO is a public utility for the purposes of the FPA.

NYISO codifies nearly all of its decision-making protocols in the OATT and MST it files with FERC. These tariffs provide comprehensive prescriptions for parameters to be achieved, parties to involve, procedures to follow, and valid bases for issuing directions and allocating resources.⁵⁶ This subsection summarizes key features of planning and tariff amendment in NYISO, both of which give prominent roles to stakeholders.⁵⁷

⁵³ FPA § 201(b). Disputes still sometimes arise over previously unexplored instances of jurisdictional line-drawing between NYISO and state entities like the New York PSC. *See, e.g., Competitive Transmission Developers v. New York Independent System Operator, Inc.*, 156 FERC ¶ 61,164, at P 5 (Sept. 8, 2016) ("CTD contends that NYISO improperly surrenders its responsibilities to the New York Commission"); *N.Y. Indep. Sys. Operator, Inc.*, 151 FERC ¶ 61,075, at P 1 (2015) (Apr. 30 Order), reh'g denied, 153 FERC ¶ 61,010, at P 3 (Oct. 2 2015) (resolving that NYISO rather than the PSC had jurisdiction to "establish[] compensation for a generator's return to service to resolve a reliability need").

⁵⁴ 16 U.S.C. § 842(b).

⁵⁵ *Id.* § 842(e).

⁵⁶ The November 2016 combined version of these tariffs weighed in at almost 2,800 pages. *See* New York Independent System Operator, Inc., NYISO Tariffs (Nov. 22, 2016), <https://perma.cc/4W5K-WQK2>.

⁵⁷ References to "stakeholders" in NYISO tariffs and manuals indicate merchant transmission developers, generation plant owners, generation developers, demand response providers, and other participants. NYISO, Reliability Planning Process Manual 2-2 (Apr. 2016).

3.2.1 Planning

NYISO's Comprehensive System Planning Process updates an operational model of facilities in NYISO and yields plans for maintaining reliability over the coming ten-year period.⁵⁸ It consists of the following four subsidiary processes:

1. Local Transmission Planning Process ("LTPP");
2. Reliability Planning Process ("RPP");
3. Congestion Assessment and Resource Integration Study ("CARIS"); and
4. Public Policy Transmission Planning Process ("PPTPP").

NYISO coordinates the timing of these subsidiary processes so that the LTPP is followed by the RPP, which is followed by the CARIS; the PPTPP begins midway through LTPP.

The LTPP gathers NYISO Transmission Owners' studies of their respective areas ("Local Transmission Plans" or "LTPs") for review by stakeholders and NYISO's Electric System Planning Working Group and Transmission Planning Advisory Subcommittee.⁵⁹ LTPs can be thought of as schematic maps of existing and planned transmission facilities, complete with descriptions of those facilities' operational features.⁶⁰

The biennial RPP builds on the LTPs drafted by each of NYISO's eight Transmission Owners.⁶¹ The RPP consists of the development, review by stakeholders, and approval by NYISO's Board of Directors of two studies. The first, known as the Reliability Needs Assessment ("RNA"), memorializes NYISO staff's assessment of whether existing and planned Bulk Power Transmission Facilities are expected to meet Reliability Criteria for resource adequacy, security, and stability

⁵⁸ See NYISO, OATT, Attachment Y, § 31 (0.0.0) (codifying approach to Comprehensive System Planning Process).

⁵⁹ See NYISO, Markets & Operations: Local Transmission Owner Planning Process, <https://perma.cc/5T6Z-9GUA> (last visited Dec. 5, 2016) ("Customers, Market Participants and other interested parties may review and comment on the planning criteria and assumptions used by each Transmission Owner, as well as other data and models used by each Transmission Owner in its LTPP.")

⁶⁰ See, e.g., Long Island Power Authority (LIPA), Local Transmission Owner Plan (LTP), Presentation to NYISO Interested Parties (Oct. 24, 2013), <https://perma.cc/824X-S67U>.

⁶¹ NYISO, 2016 Reliability Needs Assessment (Oct. 18, 2016), <https://perma.cc/7JGP-6VUS>.

over a ten-year time horizon.⁶² The RNA identifies Reliability Needs—i.e., deficiencies vis-à-vis Reliability Criteria that signal where transmission and other projects might be necessary—and specifies a Responsible Transmission Owner for each need. Once NYISO’s Board of Directors approves the RNA, NYISO requests proposals to address each identified Reliability Need⁶³ and, at the same time, seeks a “regulated backstop solution” from the Responsible Transmission Owner.⁶⁴ For the purpose of the RPP, a backstop solution serves both as a benchmark against which to assess market-based solutions’ viability and—of course—as a backstop in case no satisfactory market-based solution materializes.

The second report prepared as part of the RPP, known as the Comprehensive Reliability Plan (“CRP”), lists all viable solutions proposed to address Reliability Needs and also contains NYISO’s evaluation of those solutions. NYISO selects from among viable solutions based on their relative cost-effectiveness.

Completion of the CRP prompts the start of the third subsidiary planning process: CARIS. Like the RPP, CARIS identifies possible needs, seeks proposed solutions, and then evaluates and selects from among those solutions. The chief difference is that congestion, unlike Reliability Needs, is chiefly an issue of cost-effectiveness rather than system stability, security, or reliability. Thus both the identification and evaluation phases of CARIS involve cost-benefit analyses that can result in a decision to simply tolerate—rather than addressing—a given instance of congestion.⁶⁵

The PPTPP addresses “public policy requirements,” which NYISO defines as a “federal or New York State statute or regulation, including a New York Public Service Commission (“NYPSC”) order adopting a rule or regulation . . . , or any duly enacted law or regulation passed by a local governmental entity in New York State, that may relate to transmission planning on the

⁶² *See Id.* at 26–41.

⁶³ Proposals can include all resource types: transmission, generation, demand response, or non-transmission alternatives.

⁶⁴ Whereas market-based solutions receive compensation through NYISO-administered markets or bilateral agreements, backstop solutions receive compensation directly from NYISO pursuant to provisions of NYISO’s tariff.

⁶⁵ This is why NYISO categorizes the CARIS as part of its economic planning process rather than the RPP or public policy-oriented process. *See* NYISO, Public Policy Transmission Planning Manual 1-2 to 1-3 (July 2015), <https://perma.cc/ACT6-VVP3>.

[Bulk Power Transmission Facilities].”⁶⁶ The PPTPP was developed to identify transmission needs rooted in public policy in compliance with FERC’s Order 1000, and it looks to the NYPSC to help identify and specify public policy requirements.⁶⁷ The subjects of public policy requirements in New York include reducing congestion (on its own or as a means of reducing electricity rates) and reducing the carbon intensity of generation in the NYCA, among others.

NYISO initiates the PPTPP upon the release of a draft version of the RNA, at which point the PPTPP follows the same basic steps as the RPP and CARIS: identify needs, seek viable solutions, evaluate solutions (in the PPTPP context, make a Viability and Sufficiency Assessment), and select from among solutions based on efficiency and cost-effectiveness. A recent example of the PPTPP at work relates to plans to “unbottle” the transmission linkage connecting western New York to the hydroelectric generation and pumped storage facilities located near Niagara Falls.⁶⁸ The NYPSC designated that unbottling as a Public Policy Transmission Need after concluding that it would result in “significant environmental, economic, and reliability benefits.”⁶⁹ Whatever project or projects address a transmission need will qualify as a Public Policy Transmission Project, eligible to recover costs under NYISO’s OATT. In its comments in an ongoing NYPSC proceeding dealing with transmission needs, NYISO observed that “All of the Submittals point to the [New York Clean Energy Standard], which requires 50% of the state’s electric energy to come from renewable resources by 2030 (“50% by 30”), as a primary driver of the need for new transmission facilities in New York.”⁷⁰ Thus, it appears that many if not all transmission proposals currently before NYISO could qualify as a Public Policy Transmission Project.

⁶⁶ NYISO OATT, Attachment Y § 31.1.1.

⁶⁷ In the Matter of NYISO, Inc.’s Proposed Public Policy Transmission Needs for Consideration, Case 14-E-0454, at 2–3 (N.Y.P.S.C. Oct. 13, 2016) (Order Addressing Public Policy Transmission Need for Western New York) (describing origin and purpose of PPTPP).

⁶⁸ *Id.* at 5–7 (describing need); NYISO, Western New York Public Policy Transmission Need Project Solicitation, (Nov. 1, 2016), <https://perma.cc/ULS5-HCTJ> (requesting Solicitations to address need).

⁶⁹ Oct. 13, 2016 Order, Case 14-E-0454 at 4–5.

⁷⁰ In the Matter of New York Independent System Operator, Inc.’s Proposed Public Policy Transmission Needs for Consideration for 2016, Case No. 16-E-0558, at 7 (N.Y.P.S.C. Dec. 5, 2016), <https://perma.cc/GA4F-XZEF>.

3.2.2 Tariff Revisions and Stakeholder Involvement

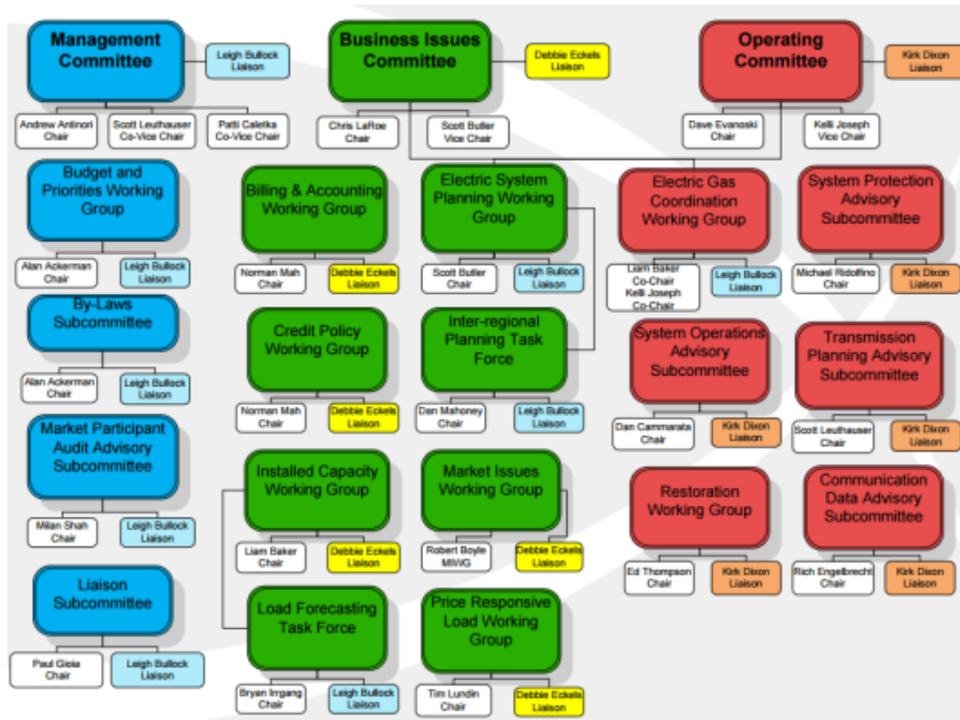
NYISO uses a multi-committee review process to make decisions, including about whether to propose a tariff revision for FERC's approval. NYISO's basic contract provides for three committees: Management, Operations, and Business Issues. Each of them is further governed by By-Laws.⁷¹ Formally, NYISO may propose revisions to its MST or OATT to FERC if majorities of the 10-member NYISO Board of Directors and the Management Committee concur.⁷² But this formal step is just the last in a more elaborate process, sometimes called the "shared governance process" or "stakeholder review process." Figure 5 depicts the structure of committees and subsidiary subcommittees and working groups whose members review, mark up, and revise proposals before the Management, Operations, or Business Issues Committee finalizes them for consideration by the Board.⁷³

⁷¹ NYISO, By-Laws of the Management Committee (Jan. 29, 2015), <https://perma.cc/5CNB-NXWS>; NYISO, By-Laws of the Operating Committee (Feb. 13, 2015), <https://perma.cc/59CZ-H9J6>; NYISO, By-Laws of the Business Issues Committee (Feb. 11, 2015), <https://perma.cc/CP59-5Y9Z>.

⁷² NYISO Agreements art. 19 (Mar. 3, 2013), <https://perma.cc/4NN2-6MAM>; By-Laws of the NYISO, Inc. art. II § 6(b) (Jan. 16, 2016), <https://perma.cc/WFR8-U7WL>.

⁷³ For a short description of what each component contributes to the whole, see NYISO, Committee Structure: Scope of Responsibilities 2–5 (2014), <https://perma.cc/WE8Q-DUZY>.

Figure 5: NYISO Committee Structure



Percolation up through this committee structure ensures that committee members receive notice and an opportunity to be heard on matters relevant to their client or constituents. NYISO's basic contract allocates votes on the Management Committee among generators, other suppliers, transmission owners, end-use consumers, and public power and environmental groups;⁷⁴ the other committees follow the same rubric.⁷⁵

3.3 FERC Oversight of NYISO

The FPA requires public utilities to notify FERC before making changes to rates or "rules and regulations affecting or pertaining to" rates.⁷⁶ Such notice must be given by filing, with FERC, new rate schedules showing the change(s) to be made to the schedules in force.⁷⁷ The new schedules will take effect after sixty days unless FERC, on its own initiative or following a

⁷⁴ Agreement § 7.06.

⁷⁵ Operating Committee By-Laws § 12.01; Business Issues Committee By-Laws § 12.01.

⁷⁶ 16 U.S.C. § 824d(d) (stating that "no change shall be made by any public utility in any . . . rate, charge, classification, or service, or in any rule, regulation, or contract relating thereto, except after sixty days' notice to the Commission").

⁷⁷ FERC may allow changes to take effect without requiring sixty days notice. *Id.*

complaint, commences a review thereof.⁷⁸ Where a review is undertaken, FERC may suspend operation of the schedules for up to five months, while it assesses their lawfulness.⁷⁹ Based on that assessment, FERC may accept or reject the schedule, in whole or in part.⁸⁰

FERC's review is intended to ensure that the rates and practices set out in the schedule are just and reasonable⁸¹ and not unduly preferential or discriminatory.⁸² These terms are not defined in the FPA or other legislation. Guidance on their meaning has, however, been provided in numerous administrative and court decisions. The U.S. Supreme Court has acknowledged that the just and reasonable standard is "incapable of precise judicial definition."⁸³ FERC is, therefore, "afford[ed] great deference . . . in its rate decisions."⁸⁴ FERC is not required to set rates at any particular level⁸⁵ or using any particular methodology.⁸⁶ The only requirement is that the methodology used appropriately balance the interests of suppliers and customers,⁸⁷ such that rates fall "within a zone of reasonableness, where [they] are neither less than compensatory nor excessive."⁸⁸ Rates must be high enough to enable suppliers to recover their costs and earn a return

⁷⁸ *Id.* § 824d(e).

⁷⁹ *Id.* at § 824d(3). The schedules will go into effect after five months, regardless of whether FERC has completed its review.

⁸⁰ *Id.* § 824e(a).

⁸¹ *Id.* § 824d(a) (requiring that "all rates . . . made, demanded, or received by any public utility for or in connection with the transmission or sale of electricity energy . . . and all rules and regulations affecting or pertaining to such rates . . . be just and reasonable").

⁸² *Id.* § 824d(b) (providing that public utilities must not "(1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect").

⁸³ *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1*, 554 U.S. 527, 532 (2008).

⁸⁴ *Id.*

⁸⁵ *Permian Basin Area Rate Cases*, 390 U.S. 747, 767 (1968).

⁸⁶ *Fed. Power Comm'n v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944).

⁸⁷ *Id.*

⁸⁸ *Farmer's Union Cent. Exch., Inc. v. Fed. Energy Reg. Comm'n*, 734 F.2d 1486, 1502 (D.C. Circuit)

on investment,⁸⁹ but not so high as to result in customer exploitation, abuse, or gouging or unjust discrimination between customer groups.⁹⁰

The same just and reasonable standard applies to both cost- and market-based rates. With respect to the latter, FERC has taken the view that rates set in competitive markets will fall within the “zone of reasonableness,” provided no participant can exercise market power.⁹¹ This approach has been upheld by the courts. In *Tejas Power Corp. v. FERC*, the D.C. Circuit observed that “[i]n a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable.”⁹² In this context, market power has been defined as the ability of a seller to “significantly influence price in the market by withholding service and excluding competitors for a significant period of time.”⁹³ Prior to approving a market-based tariff, FERC requires the seller to demonstrate that it lacks or has adequately mitigated market power, and is unable to erect barriers to entry.⁹⁴ FERC monitors sellers’ activities in the market to ensure that they do not re-attain market power.⁹⁵

FERC has also taken steps to enhance the functioning of markets and improve their competitiveness. For example, beginning in 2008, FERC adopted several orders aimed at removing barriers to the participation of demand-side resources in markets.⁹⁶ More recently, in 2014, FERC initiated a broad-ranging review of market design and operational practices that may impair

⁸⁹ *Hope Nat. Gas Co.*, 320 U.S. at 603.

⁹⁰ *Farmer’s Union Cent. Exch., Inc.*, 734 F.2d at 1502.

⁹¹ *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities* 119 FERC ¶ 61,295.

⁹² *Tejas Power Corp. v. FERC*, 908 F.2d 998, 1004 (D.C. Cir. 1990).

⁹³ This definition was adopted in FERC’s first market based rate authorization. See *Citizens Power & Light Corp.*, 48 FERC ¶ 61,777 (1989).

⁹⁴ *Order No. 697, Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities* 119 FERC ¶ 61,295 (Jun. 21, 2007).

⁹⁵ *Id.*

⁹⁶ *Order No. 719, Wholesale Competition in Regions with Organized Electric Markets* 125 FERC ¶ 61,071 (Oct. 17, 2008); *Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets* 134 FERC ¶ 61,187 (Mar. 156, 2011) [hereinafter *Order No. 745*].

competition.⁹⁷ Based on the findings of that review, FERC has required various design changes, aimed at improving how markets run.⁹⁸ Thus, as the Supreme Court has observed, FERC “ensure[s] ‘just and reasonable’ wholesale [electricity] rates by enhancing competition – attempting . . . to break down regulatory and economic barriers that hinder a free market in wholesale.”⁹⁹

4. PRICING CARBON IN ELECTRICITY MARKETS

There is growing interest among ISO/RTOs in incorporating carbon pricing into wholesale energy and/or capacity markets. In August 2016, NYISO launched the Integrating Public Policy Project (“IPPP”) to assess whether introduction of a carbon price “would improve the overall efficiency of . . . energy and capacity markets,” among other things.¹⁰⁰ Proposals for how to better respond to state and federal policies aimed at reducing carbon dioxide emissions from electricity generation have also been considered by CAISO, ISO-NE, and PJM.

4.1 Electricity Generation and Carbon Dioxide Emissions

Electricity generation is a leading source of carbon dioxide emissions in the U.S. According to the U.S. Environmental Protection Agency (“EPA”), electricity generation emitted over two billion metric tons of carbon dioxide in 2014, equivalent to 36.7 percent of national carbon dioxide emissions.¹⁰¹ The level of emissions from a particular generating unit varies depending on the fuel used and its carbon-intensity.¹⁰² Coal is the most carbon-intensive generating fuel, followed by oil (which contains twenty-five percent less carbon than coal per unit of energy) and gas (which

⁹⁷ FERC, NOTICE: PRICE FORMATION IN ENERGY AND ANCILLARY SERVICES MARKETS DOCKET OPERATED BY REGIONAL TRANSMISSION ORGANIZATIONS AND INDEPENDENT SYSTEM OPERATORS (2014), <https://perma.cc/W2ZL-BZEB>.

⁹⁸ See e.g., Order No. 825, Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators 155 FERC ¶ 61,276 (Jun. 16, 2016) [hereinafter Order No. 825].

⁹⁹ *Morgan Stanley*, 554 U.S. at 536.

¹⁰⁰ MIKE DESOCIO, NYISO, 2017 INTEGRATING PUBLIC POLICY: DETAILED SCOPE 3 (2016), <https://perma.cc/MQ3P-LYTD>.

¹⁰¹ EPA, INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990 – 2014 ES-5 (2016), <https://perma.cc/7DWK-9GN6>.

¹⁰² *Id.* at 3-6.

contains forty-five percent less carbon than coal).¹⁰³ Other generating fuels, such as nuclear and renewables, contain little or no carbon.

When coal and other fossil fuels are combusted during electricity generation, the carbon stored in the fuel is oxidized, producing carbon dioxide and small amounts of other gases.¹⁰⁴ The Energy Information Administration (“EIA”) estimates that coal-fired generating units emit, on average, 2.1 pounds of carbon dioxide per kilowatt hour (“KWh”) of electricity generated.¹⁰⁵ Carbon dioxide emissions from oil and gas-fired units average 1.7¹⁰⁶ and 1.2¹⁰⁷ pounds per KWh of electricity generated respectively.

Carbon dioxide traps heat in the earth’s atmosphere, causing surface temperatures to rise. According to the 2014 National Climate Assessment, average annual temperatures in the U.S. have risen by 1 to 2°F since 1895, and may rise a further 2 to 4°F “over the next few decades.”¹⁰⁸ Temperatures have risen far faster in Alaska—since 1949 average annual temperatures have risen by 3.3°F and average winter temperatures by 6.1°F.¹⁰⁹ Rising temperatures lead to more variable precipitation patterns and increase the frequency and severity of extreme weather events. Impacts expected in the New York region include more frequent and intense heat waves, more intense precipitation events, and storm surges incident to sea level rise and more powerful coastal

¹⁰³ *Id.*

¹⁰⁴ *Id.* at 3-8. The other gases emitted include carbon monoxide, methane, and non-methane volatile organic compounds. These gases are, for the most part, eventually oxidized to carbon dioxide in the atmosphere.

¹⁰⁵ EIA, *How Much Carbon Dioxide is Produced per Kilowatt hour when Generating Electricity with Fossil Fuels?* FREQUENTLY ASKED QUESTIONS, <https://perma.cc/VHF4-8EDV> (last visited Nov. 23, 2016) (estimating emissions from generating units using bituminous coal, subbituminous coal, and lignite coal at 2.07, 2.16, and 2.17 pounds per kilowatt hour (“KWh”) respectively).

¹⁰⁶ *Id.* (estimating emissions from generating units using distillate oil (no. 2) and residual oil (no. 6) at 1.647 and 1.76 pounds per KWh respectively).

¹⁰⁷ *Id.* (estimating emissions from generating units using natural gas at 1.22 pounds per KWh).

¹⁰⁸ U.S. Global Change Research Program, Chapter 1: Overview and Report Findings, in *CLIMATE CHANGE \$84IMPACTS IN THE UNITED STATES: THE THIRD NATIONAL CLIMATE ASSESSMENT 8* (Jerry M. Melillo, Terese (T.C.) Richmond, and Gary W. Yohe eds., 2014), <https://perma.cc/6S2L-66DV>.

¹⁰⁹ University of Alaska-Fairbanks, The Alaska Climate Research Center, *Temperature Changes in Alaska*, <https://perma.cc/M6T7-XND2> (last visited Dec. 6, 2016).

storms.¹¹⁰ These impacts are already being felt in many areas and “have affected and will continue to affect human health, water supply, agriculture, transportation, energy . . . and many other sectors of society” over coming decades.¹¹¹

4.2 Regulation of Carbon Dioxide Emissions from Electricity Generation

Recognizing that climate change endangers public health and welfare, in December 2009, the EPA listed carbon dioxide as an air pollutant under the Clean Air Act.¹¹² EPA regulations adopted in August 2015 and known as the Clean Power Plan aim to reduce emissions from existing electric generating units by thirty-two percent below 2005 levels by 2025.¹¹³ The regulations establish emissions limits for each state’s electricity sector, but do not specify how those limits are to be achieved. This is left to the discretion of the states, which have wide latitude in deciding how to comply. A number of states were considering carbon pricing as a means of complying with the Clean Power Plan.¹¹⁴ Notably however, many states suspended their compliance work following the February 2016 Supreme Court decision to stay implementation of the Clean Power Plan pending resolution of legal challenges thereto.¹¹⁵ Even if the Clean Power Plan is upheld by the courts, it is unlikely to be implemented having been strongly opposed by President Trump during his campaign.¹¹⁶

¹¹⁰ *New York City Panel on Climate Change 2015 Report Executive Summary*, 1336 ANN. N.Y. ACAD. SCI. 9, 9–11 (Jan. 2015).

¹¹¹ *Id.* at 9.

¹¹² *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 75 Fed. Reg. 66,496 (Dec. 15, 2009) (40 CFR Ch. 1).

¹¹³ *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, 80 Fed. Reg. 64,662 (Oct. 23, 2015) (40 CFR Pt. 60). On February 9, 2016, the Supreme Court stayed implementation of the regulations, pending judicial review. See *West Virginia v. Env’tl. Protection Agency*, 136 S. Ct. 1000 (2016).

¹¹⁴ See, e.g., MELINDA E. TAYLOR & ROMANY M. WEBB, *EPA’S CLEAN POWER PLAN: IMPLEMENTATION OPTIONS 15* (2015), <https://perma.cc/36NT-54PV>.

¹¹⁵ *E&E News, Supreme Court Stay Response, E&E’S POWER PLAN HUB*, <https://perma.cc/3RW5-VDGX> (last visited Dec. 28, 2016).

¹¹⁶ Annie Sneed, *Trump’s First 100 Days: Climate and Energy*, *SCIENTIFIC AMERICAN*, Nov. 29, 2016, <https://perma.cc/RKF8-D7U7>.

4.3 Why Put a Price on Carbon Dioxide Emissions?

The costs associated with carbon dioxide emissions are generally not reflected in electricity market prices.¹¹⁷ Those costs take the form of “externalities” – impacts that are felt by third parties or the public at large—but have no price attributed to them by market participants.¹¹⁸ This results in a market failure, whereby prices are lower than costs, leading to higher levels of production and consumption than are socially optimal.¹¹⁹ Government intervention is, therefore, needed to ensure that social costs are fully taken into account in production and consumption decisions.¹²⁰ Such intervention could take a number of forms, including command-and-control regulations that limit the use of fossil fuels in electricity generation or market-based instruments, such as carbon pricing.

A carbon price internalizes the external costs of carbon dioxide emissions from electricity generation and thus increases the cost of generation using fossil fuels, leading to lower demand from consumers and encouraging generators to switch to cleaner alternatives. Generators will make the switch and/or take other steps to reduce emissions wherever the costs of doing so are less than the carbon price. In this way, carbon pricing affords generators flexibility to find and exploit the most cost-effective emissions reductions. It tends to be more efficient than command-and-control regulation, which may force generators to pursue higher-cost emissions reductions.

Despite these benefits, to date, Congress has failed to enact legislation establishing a national carbon pricing scheme. In the absence of federal action, some states have adopted their own, more limited pricing schemes. One example is California, which has established a cap-and-

¹¹⁷ For a discussion of this issue, see NOAH KAUFMAN ET AL., WORLD RESOURCES INSTITUTE, PUTTING A PRICE ON CARBON: REDUCING EMISSIONS 6 (2016), <https://perma.cc/4NFQ-K3AD>.

¹¹⁸ *Id.*

¹¹⁹ *Id.*

¹²⁰ NATIONAL RESEARCH COUNCIL, HIDDEN COSTS OF ENERGY: UNPRICED CONSEQUENCES OF ENERGY PRODUCTION AND USE 3 (2010), <https://perma.cc/2AHP-VD5W> (stating that, when prices do not reflect external costs, they “are ‘hidden’ in the sense that government and other decision makers, such as electric utility managers, may not recognize the full costs of their actions. When market failures like this occur, there may be a case for government interventions in the form of regulations, taxes, fees, tradable permits, or other instruments that will motivate such recognition”).

trade program requiring in-state electricity generators and importers¹²¹ emitting 25,000 metric tons or more of carbon dioxide equivalent per year to purchase allowances, at prices set through quarterly auctions.¹²² Another even more limited example is the Regional Greenhouse Gas Initiative (“RGGI”), in which New York and eight other north-eastern states participate. As part of RGGI, fossil fuel generators with at least twenty-five megawatts (“MW”) of capacity in New York are required to purchase carbon dioxide emissions allowances, through quarterly auctions.¹²³ RGGI thus assigns a price to approximately eight percent of state-wide emissions from all sectors; it ignores emissions from smaller electricity generators and electricity imports, as well as direct emissions from the industrial, transportation, or agricultural sectors.¹²⁴

4.4 Proposals for Carbon Pricing in ISO/RTOs

Several ISO/RTOs have recently explored mechanisms that would support the direct or indirect pricing of generation sources’ carbon intensity. The mechanisms and the reasons why they are being considered are summarized in this part. One notable impetus for this exploration in NYISO, PJM, CAISO, and ISO-NE has been EPA’s Clean Power Plan. The 2016 election, by putting the fate of the Clean Power Plan in doubt, has raised questions about the direction each ISO/RTO will take. While rescission of the Clean Power Plan would remove a key driver for action, it would not, from a legal perspective, directly affect ISO/RTOs’ authority to adopt a carbon pricing scheme. (This might change, should the Trump Administration and Congress undo EPA’s 2009 Endangerment Finding and the various regulatory authorities built upon it.¹²⁵) For many

¹²¹ An electricity importer’s emissions are calculated based on the annual emissions from each of its sources. See CAL. CODE REGS. tit. 17 § 95812(c)(2)(B).

¹²² *Id.* § 95852(b). See also *id.* § 95910 et seq.

¹²³ RGGI, Inc., *New York: Facility Information*, <https://perma.cc/BQ7F-KL4S> (last visited Dec. 7, 2016)

¹²⁴ Lucas Bifera, Center for Climate and Energy Solutions, *Regional Greenhouse Gas Initiative 2 fig.1* (Dec. 2013), <https://perma.cc/E28K-L5D7>; see also New York State Energy Research and Development Authority, *New York State Greenhouse Gas Inventory and Forecast: Inventory 1990-2011 and Forecast 2012-2030; Updated Final Report*, at S-2 (June 2015), <https://perma.cc/Q76D-AQW8>.

¹²⁵ See Christopher J. Bateman & James T. B. Tripp, *Toward Greener FERC Regulation of the Power Industry*, 38 HARV. ENVTL. L. REV. 275, 305 (2014) (“in today’s dominant regulatory and policy paradigm,

ISO/RTOs, including NYISO, state-level policies (e.g., New York's CES) will continue to drive interest in carbon pricing.

4.4.1 New York ISO

NYISO's IPPP will assess "[w]hether a redesign is needed in the wholesale market" and, in particular, whether and how to "internalize the cost of carbon" to improve market efficiency.¹²⁶ The IPPP was launched to "investigate potential market impacts from the implementation of the [CES]"¹²⁷ adopted by the NYPSC in August 2016.¹²⁸ As part of the IPPP, NYISO will consider "[a]lternative market friendly approaches" to achieving the goals of the CES, including carbon pricing.¹²⁹

4.4.2 PJM Interconnection

An August 2016 PJM white paper put forward a mechanism for reconciling two competing priorities in the PJM region:

1. states' subsidies and price supports for renewable generation, which depress energy market prices; and
2. timely investments in new generation capacity, which rely on signals sent by market price rises.¹³⁰

That mechanism would involve a two-stage auction. In Stage 1, subsidized resources and the demand they would serve ("related demand") would both be removed from the auction for the purpose of determining capacity requirements for the relevant time period. The resources that clear the auction *and* the subsidized resources would both take on capacity commitments, all with identical performance requirements. Compensation for the subsidized resources' capacity commitments would be entirely the responsibility of their sponsoring state government; the

the environmental consequences of electricity generation are 'matters directly related to the economic aspects' of such transactions.") (emphasis added).

¹²⁶ DESOCIO, *supra* note 100, at 3.

¹²⁷ *Id.* at 2.

¹²⁸ Press Release, New York State, Governor Cuomo Announces Establishment of Clean Energy Standard that Mandates 50 Percent Renewables by 2030 (Aug. 1, 2016) (on file with authors).

¹²⁹ *Id.*

¹³⁰ Bresler, *supra* note 1.

related demand would not have to pay. In Stage 2, subsidized resources would be included in the auction, but at a reference price that approximates the unsubsidized cost for that resource type at the relevant locational node. Any resource that fails to clear in Stage 1 would not be eligible to receive compensation through the auction, even if it bids into Stage 2 at a price below the second stage clearing price.

This two-stage process would not assign a price to carbon, but would make it easier for states located in the PJM balancing area to do so without disrupting the operation of the wholesale energy or capacity markets.

4.4.3 California ISO

California's legislature and governor have called for expansion of CAISO to encompass other western states on the grounds that such expansion will serve several goals, including lowering costs, improving reliability, and supporting renewable energy development.¹³¹ That expansion would, however, mean departing from a situation where the California Public Utility Commission and CAISO largely share a geographic footprint that does not extend beyond California's borders. The new expanded CAISO would have to devise and manage a wholesale marketplace that spans multiple states only one of which assigns a price to GHG emissions. CAISO devised three possible mechanisms ("Options") for navigating this circumstance:

1. Compare the actual dispatch of electricity from particular sources that serve load in California to weeks- or months-long baselines, and thereby attribute estimated GHG emissions to particular sources based on the differences between actual and baseline dispatch;
2. Conduct quick (at five-minute intervals) two-step analyses that first determine the most cost-effective regional dispatch of electricity and then attribute GHG emissions to sources; or

¹³¹ California Clean Energy and Pollution Reduction Act of 2015, c. 547 § 13 (amending Pub. Util. Code § 359.5 (a) to read: "It is the intent of the Legislature to provide for the transformation of the Independent System Operator into a regional organization . . . , and that the transformation should only occur where it is in the best interests of California and its ratepayers."); Letter from G. Brown, Governor of California, to California legislative leadership regarding CAISO expansion 1 (Aug. 8, 2016), <https://perma.cc/68RM-KPDV>; *see also* Brattle Group, Senate Bill 350 Study: The Impacts of a Regional ISO-Operated Power Market on California, I-xiv (July 8, 2016), <https://perma.cc/TVD8-8NVT> (noting that demand for integration of more renewables prompts need to expand).

3. Conduct a two-step analysis similar to Option 2, but rather than mapping dispatch and attributing emissions with complete specificity (a computationally difficult task), impose either an averaged emissions factor or a “hurdle rate” on imported generation, making exceptions for generators party to bilateral contracts with California LSEs.¹³²

Of these, CAISO and the California Air Resources Board (“CARB”) are now considering only Option 3.¹³³ CAISO and CARB raised concerns about Option 1 because CARB’s regulations would not permit the crediting of emissions reductions involved.¹³⁴ And CAISO indicated that performing the quick calculations required for Option 2 would exceed its computational capacity.¹³⁵

4.4.4 ISO New England

The New England Power Pool (“NEPOOL”) initiated the Integrating Markets and Public Policy (“IMAPP”) stakeholder process in August 2016 to explore options for decarbonizing the electric grid without sacrificing reliability or market-based electricity price formation.¹³⁶ In addition to anticipating Clean Power Plan compliance measures, two other factors motivated IMAPP: first, natural gas has dominated regional capacity additions to such an extent since the late 1990s that ISO-NE is now susceptible to significant adverse effects should there be a natural gas supply shock or price jump; and second, wholesale market prices are artificially reduced by the inclusion of subsidized resources in capacity auctions, which in turn distorts incentives for investment in new

¹³² G. Angelidis & D. Tretheway, Regional Integration California Greenhouse Gas Compliance and EIM Greenhouse Gas Enhancement Straw Proposal 9–10 (Nov. 17, 2016), <https://perma.cc/8EE6-8MEU>.

¹³³ Don Tretheway, Regional Integration-California Greenhouse Gas Compliance Initiative—Second Update 42 (Oct. 13, 2016), <https://perma.cc/4X4F-2YU2>.

¹³⁴ *Id.* at 16.

¹³⁵ *Id.* at 18 (“Current computational power would require simplifying (less accurate) first pass to ensure [real-time dispatch] successfully completes”).

¹³⁶ Chairman’s Opening Remarks, NEPOOL IMAPP Initiative (Aug. 11, 2016), <https://perma.cc/3PU4-8X5T> (“Our goal is to achieve and maintain our high standards for reliability that our constituents demand, and to do so using the discipline of competition, *while incorporating the states’ goals of decarbonizing our industry over time.*”) (emphasis added). IMAPP agendas, presentations, and white papers are all posted online. See NEPOOL, *Integrating Markets and Public Policy*, <https://perma.cc/8BX8-WLY7> (last visited Nov. 27, 2016).

capacity. (All six states within ISO-NE's territory provide for some form of support for renewables.¹³⁷)

Participants put forward fifteen different proposals, which fall into four broad categories as follows:

1. introduction of a carbon pricing scheme, whereby a carbon adder would be imposed on generators' bids, reflecting their carbon intensity;
2. changes to the forward capacity market, such that certain generators would receive payments for both their capacity and their zero emission attributes;
3. introduction of a two-stage auction, similar to that proposed by PJM, which insulates wholesale market price formation from state policies; and
4. establishment of a Forward Clean Energy Market, in which LSEs could procure long-term commitments (up to ten years) for zero-emitting energy (not capacity) resources.

5. NEW YORK'S EXISTING CARBON PRICING POLICIES

New York has introduced not one but two partial carbon prices, first by participating in RGGI, a cap-and-trade scheme, and more recently with the NYPSC's adoption of the CES. Both programs focus on the electricity sector but take different approaches to price formation and leakage, i.e., out-of-state emissions that are (i) not subject to restrictions or pricing, and (ii) caused by in-state electricity consumption.¹³⁸ As described in this part, their approaches to prices and leakage have important legal implications.

¹³⁷ Gordon van Welie, ISO New England, *State of the Grid: ISO on Background* 30 (Jan. 26, 2016), <http://bit.ly/2g8DpkA> (noting that all six states impose RPSs); *see also e.g.*, Mass. H.B. 4568 (2016) (authorizing state agency to draft and execute PPAs for renewable generation); Conn. Pub. Act No. 15-107 (same).

¹³⁸ *See* Jonathan L. Ramseur, Congressional Research Service, *The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Congress* 16 (Apr. 27, 2016), <http://bit.ly/2gJtWhd>. A more general definition of leakage is: an "increase in emissions by entities not subject to a regulation, due to increases in costs for generators subject to the regulation." Daniel Shawhan, *Emission Reductions and "Leakage" from US State Cap-and-Trade Programs*, slide 5 (Sept. 19, 2013), <https://perma.cc/PEJ7-F9FL>.

5.1 RGGI

RGGI, the older of New York's two carbon pricing programs, requires New York's seventy-six largest in-state fossil fuel-fired generators to purchase carbon dioxide emissions allowances.¹³⁹ The legal basis for New York's participation in RGGI is a set of regulations adopted by the state Department of Environmental Conservation ("DEC") and Energy Research and Development Authority ("NYSERDA").¹⁴⁰ State regulations require covered generators to purchase carbon dioxide emissions allowances through quarterly auctions. Auctions are conducted using a sealed bid format in which each generator may submit multiple bids to purchase a specified number of allowances at different prices.¹⁴¹ Bids are ranked by price, from high to low, and allowances issued until cumulative demand equals supply.¹⁴² A region-wide declining cap limits the number of allowances available for purchase.¹⁴³ The cap was set at 86.5 million allowances in 2016¹⁴⁴ and will

¹³⁹ RGGI, Inc., *New York: Facility Information*, <https://perma.cc/BQ7F-KL4S> (last visited Dec. 7, 2016)

¹⁴⁰ 6 NYCRR pt. 242 (DEC: CO2 Budget Trading Program; requiring covered facilities to purchase allowances); 21 NYCRR pt. 507 (NYSERDA: CO2 Allowance Auction Program; authorizing NYSERDA to coordinate New York facilities' participation in auctions). Governor Pataki along with the governors of other RGGI states signed a Memorandum of Understanding in 2005. Regional Greenhouse Gas Initiative, Memorandum of Understanding (Dec. 20, 2005), <https://perma.cc/G6YQ-443U>. That document has no legal force, and merely memorialized the governors' commitments to pursue whatever was necessary for their respective states to participate. See *Thrun v. Cuomo*, 976 N.Y.S.2d 320, 324 (App. Div. 3d 2013). The only legal challenge brought against New York's participation in RGGI argued that (i) because it is effectively a tax, legislative approval is required; (ii) the Memorandum of Understanding is an unconstitutional interstate compact; and (3) the regulations themselves were arbitrary and capricious and promulgated pursuant to an "error of law." *Thrun* at 323. The court rejected all of these arguments, which were raised well after the four-month statute of limitations had run. *Id.* at 324.

¹⁴¹ RGGI, INC., FACT SHEET: RGGI CO2 ALLOWANCE AUCTIONS 1 (2016), <https://perma.cc/AKD6-V6B8>.

¹⁴² RGGI, INC., CO₂ ALLOWANCE AUCTIONS: FREQUENTLY ASKED QUESTIONS 10 (2016), <https://perma.cc/MP8D-R33N>.

¹⁴³ See generally Ramseur, *supra* note 138.

¹⁴⁴ RGGI, Inc., *2016 Allowance Allocation, PROGRAM DESIGN*, <https://perma.cc/6HM3-ZUFL> (last visited Dec. 15, 2016).

decline to 76 million allowances by 2020.¹⁴⁵ Each allowance permits the holder to emit one ton of carbon dioxide.

Because RGGI states impose a price on carbon dioxide emissions, in the form of an allowance cost, and the states around them do not, the program is vulnerable to leakage. Like other RGGI states, New York's RGGI-implementing regulations do not currently seek to prevent leakage. Recent analyses of whether this leakage tolerance has undermined RGGI's carbon price conclude that, to date, RGGI's emissions pricing has increased imports,¹⁴⁶ but that access to imports from relatively cheap natural gas-fired generation in Pennsylvania and Ohio and hydropower in Quebec have meant a decrease in emissions nonetheless.¹⁴⁷ Regardless of whether this fortuitous circumstance is likely to last, RGGI participants have committed to examining options for improving the tracking of imports from outside RGGI and potentially adjusting the prices assigned to those imports to prevent leakage.¹⁴⁸

¹⁴⁵ For a discussion of the cap, see ELIZABETH A. STANTON ET AL., SYNAPSE ENERGY ECONOMICS, THE RGGI OPPORTUNITY: RGGI AS THE ELECTRIC SECTOR COMPLIANCE TOOL TO ACHIEVE 2030 STATE CLIMATE TARGETS 1–2 (2016), <https://perma.cc/D6T2-7UK7>.

¹⁴⁶ Harrison Fell & Peter Maniloff, Beneficial Leakage: The Effect of the Regional Greenhouse Gas Initiative on Aggregate Emissions, Colorado School of Mines Division of Econ. & Bus. Working Paper 2015-06, at 23–24 (June 2015), <https://perma.cc/543W-8V6X> (identifying a 2451.95 gigawatt-hours per month increase in imports into New York from PJM during RGGI's implementation); *but see* Andrew G. Kindle et al., An empirical test for inter-state carbon-dioxide emissions leakage resulting from the regional greenhouse gas initiative (Apr. 2011), <https://perma.cc/MD2R-CYBS> (finding no empirical evidence of leakage in Pennsylvania-New York electricity transmission data from first year of RGGI's operation).

¹⁴⁷ Fell & Maniloff, *supra* note 144. Fell and Maniloff find that in regions that export electricity to New York, RGGI's carbon price seems to have prompted capacity factor increases of ten to eleven percent by gas-fired generation sources—but no increases by coal-fired sources. These have offset capacity factor reductions of seven to ten percent by New York-based coal-fired generators. *Id.* at 17–18. *See also* RGGI, CO₂ Emissions from Electricity Generation and Imports in the Regional Greenhouse Gas Initiative: 2013 Monitoring Report 6–7, (Aug. 2016), <https://perma.cc/8KVD-QDGW> (reporting net imports from PJM and Quebec).

¹⁴⁸ *See* RGGI, Inc., RGGI 2012 Program Review: Summary of Recommendations to Accompany Model Rule Amendments 3 (Feb. 2013), <https://perma.cc/6DKK-KQYX>.

5.2 CES

New York’s CES, adopted by the NYPSC in August 2016, aims by 2030 to reduce state-wide GHG emissions by forty percent from a 1990 baseline. While this 40 by 30 goal applies economy-wide, the bulk of emissions reductions are expected to come from the electricity sector, with the CES requiring half of the state’s electricity to be generated using renewable energy sources. The CES consists of three “tiers” of requirements for New York LSEs,¹⁴⁹ but is more usefully understood as a combination of two programs, one oriented to renewables (Tiers 1 and 2), and the other (Tier 3) to three of the state’s four nuclear power plants. As explained below, neither program assigns a price directly to carbon, but each assigns a price to “attributes” that include the non-emission of carbon.

CES Tiers 1 and 2 extend and modify the state’s existing RPS, which required LSEs to collect a surcharge, payable to NYSERDA, and authorized NYSERDA to acquire “RPS attributes,” embodied in RECs, from renewable generators.¹⁵⁰ This approach kept the REC market separate from the market for electricity and also allowed NYSERDA to steer investments in utility-scale and smaller renewable generation developments. Under the new CES Order, LSEs can comply with the RPS by acquiring RECs from NYSERDA, from renewable generators directly, or by making “Alternative Compliance Payments” to NYSERDA.¹⁵¹ One qualifying REC is “produced” alongside each MWh of electricity produced by a renewable facility that began commercial operation after January 1, 2015.¹⁵² LSEs must acquire RECs in proportion to the annual load they supply—0.6 percent of load supplied in 2017, 1.1 percent in 2018, up to 4.8 percent in 2021.¹⁵³

CES Tier 3 requires LSEs to purchase ZECs “produced” by three of the state’s four nuclear generating stations.¹⁵⁴ As with the RECs required to be purchased under Tiers 1 and 2, the Tier 3

¹⁴⁹ NYPSC CES Order (Aug. 1, 2016).

¹⁵⁰ For a description of the RPS first adopted in 2004, see New York State Department of Public Service, 03-E-0188: Renewable Portfolio Standard, <https://perma.cc/6YTE-EPMV> (updated June 3, 2016).

¹⁵¹ CES Order at 14–18, 94, 106–10.

¹⁵² *Id.*

¹⁵³ *Id.* at 14.

¹⁵⁴ CES Order at 20, 119–52.

ZECs place a value on a zero-emitting attribute and so are separate from the electric energy sold by the nuclear generators. However, three key alleged differences have led diverse parties to challenge Tier 3 on the grounds that it violates the dormant Commerce Clause (“dCC”) and is pre-empted by the FPA, namely:¹⁵⁵

- (1) out-of-state generators cannot actually qualify to sell ZECs, even there is no formal mechanism preventing them from doing so;
- (2) ZEC prices will be set by the NYPSC and limited by wholesale market prices; and
- (3) ZECs will soak up ratepayer spending in a way that is likely to suppress wholesale capacity market prices.¹⁵⁶

It appears that the Supreme Court’s recent *Armstrong* decision, which held that “[t]he Supremacy Clause . . . does not create a cause of action,”¹⁵⁷ may well rescue the CES from challenges arguing that it is pre-empted by the FPA. Thus Tier 3’s chief legal danger relates to challenges rooted in the dCC.

6. MECHANISMS OF A NYISO CARBON PRICING SCHEME

Partly in response to adoption of the CES, NYISO launched the IPPP to evaluate options to “achieve New York’s . . . decarbonisation goals at least cost,” consistent with the operation of wholesale markets.¹⁵⁸ The focus is on “approaches that would internalize the cost of carbon

¹⁵⁵ Complaint, Coalition for Competitive Electricity et al. v. Zibelman, Case 1:16-cv-08164 (S.D.N.Y. Oct. 19, 2016).

¹⁵⁶ See CES Order at 108 (“For the Year 2017 compliance period . . . [t]he REC price offered will equal the weighted average cost per MWh NYSERDA paid to acquire the RECs to be offered,” i.e., they will reflect the cost of developing and operating renewable generation, “plus a reasonable Commission-approved adder to cover the administrative costs and fees incurred by NYSERDA to administer Tier 1.”).

¹⁵⁷ *Armstrong v. Exceptional Child Ctr., Inc.*, 135 S. Ct. 1378, 1383 (2015); see also *Mont.-Dakota Utils. Co. v. Nw. Pub. Serv. Co.*, 341 U.S. 246, 251 (1951) (holding that FPA does not provide for any private right of action); cf. *Allco Finance Ltd. v. Klee*, Case 16-2946, 2016 WL (2d Cir. DATE 2017) (petitioner brought case via cause of action expressly granted by Congress for claims arising under Public Utility Regulatory Policy Act but not the FPA more generally).

¹⁵⁸ DESOCIO, *supra* note 100, at 5.

emissions” in markets.¹⁵⁹ To that end, NYISO could set a dollar value for each ton of carbon dioxide emitted during electricity generation (the “carbon price”), which would then be used to calculate a carbon fee for each generating unit, reflecting its emissions profile. Ideally, this calculation would be based on the generating unit’s actual emissions¹⁶⁰ as follows:

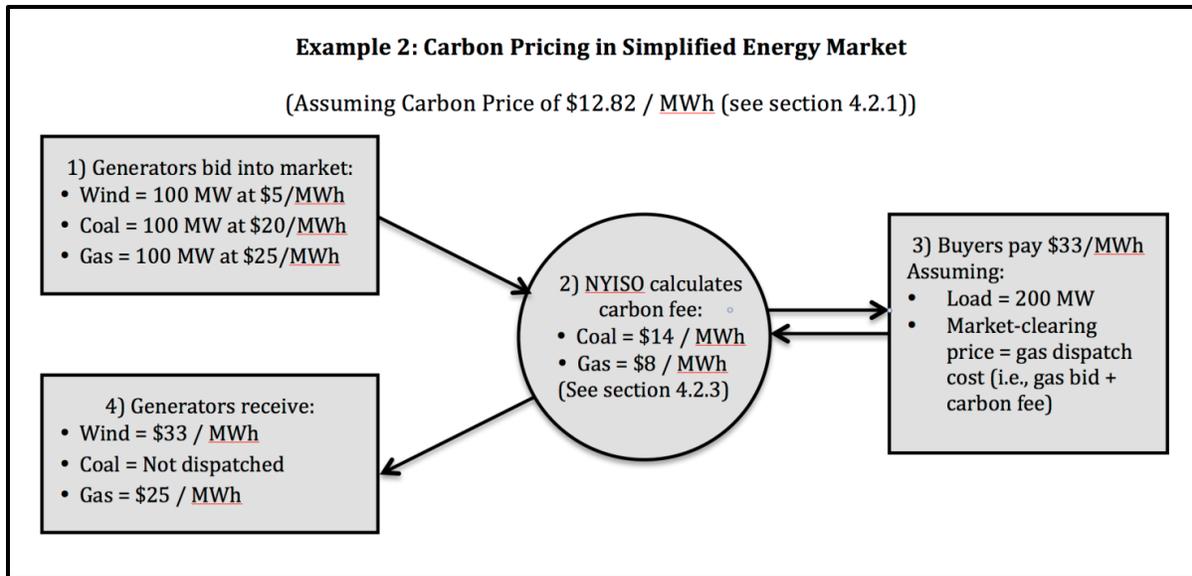
$$\text{Carbon fee (\$/MWh)} = \text{carbon price (\$/ton)} \times \text{unit emissions (tons/MWh)}$$

A carbon fee would be calculated for all in- and out-of-state generators bidding into energy markets administered by NYISO. While the same carbon price would be applied to all units, regardless of technology, the resulting carbon fee would vary depending on the fuel used. Coal-fired generating units would face the highest carbon fee, followed by oil and then natural gas.

Each generating unit’s carbon fee would be added to its energy market bid to produce a dispatch cost which would be used by NYISO to determine the dispatch order. The likely effect would be a re-ordering of dispatch, with coal- and oil-fired generating units dispatched less frequently and natural gas and renewable generators more frequently, compared to the situation without a carbon fee (compare examples 1 and 2). The dispatch cost of the marginal generator would determine the market-clearing price. Generators would receive that price less their carbon fee.

¹⁵⁹ *Id.*

¹⁶⁰ In the alternative, the calculation could be based on the carbon intensity of the fuel used by the generating facility, and its heat rate. That is: carbon fee = carbon price x fuel carbon intensity x heat rate.



6.1 Setting the Carbon Price

Various technical issues will need to be considered in designing a carbon pricing) scheme. Key among these is the level at which to set the carbon price. As discussed in part 4.3 above, carbon pricing generally aims to internalize the external costs of carbon dioxide emissions.¹⁶¹ While the New York public policy triad of RGGI, RECs, and ZECs is based on multiple aims, at the root of all of them is the reflection in market prices of the cost of GHG emissions, whether directly or in the form of a non-emitting attribute. To estimate the costs imposed by GHG emissions, the federal government has developed the social cost of carbon (“SCC”), which reflects:

the economic damages associated with a small increase in carbon dioxide . . . emissions, conventionally one metric ton, in a given year . . . [It] is meant to be a comprehensive estimate of the climate change damages and includes, among other things, changes in agricultural productivity, human health, property damages from increased flood risk and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning.¹⁶²

¹⁶¹ Interagency Working Group on Social Cost of Carbon, Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (May 2013, revised July 2015), <https://perma.cc/3NCG-6ZQT>.

¹⁶² EPA, FACT SHEET: SOCIAL COST OF CARBON 1 (2015), <http://bit.ly/2a9QhmW>.

The SCC is calculated by quantifying the current and future damage expected to result from one metric ton of carbon dioxide.¹⁶³ That figure is then discounted back to present value to arrive at the SCC.¹⁶⁴ The government has used three different discount rates to calculate three SCCs shown in Table 1 below.¹⁶⁵ Each SCC increases over time as the incremental impact of emissions rises in line with the atmospheric concentration of carbon dioxide.¹⁶⁶

Table 1: SCC Calculated by the Federal Government¹⁶⁷

Year in which carbon dioxide emissions occur	SCC (2007 \$ / metric ton)		
	5% discount rate	3% discount rate	2.5% discount rate
2015	\$11	\$36	\$56
2020	\$12	\$42	\$62
2025	\$14	\$46	\$68
2030	\$16	\$50	\$73
2035	\$18	\$55	\$78
2040	\$21	\$60	\$84
2045	\$23	\$64	\$89
2050	\$26	\$69	\$95

The SCC was developed to assist federal agencies in performing cost benefit analyses during rulemaking.¹⁶⁸ There is, however, support for its use in other contexts.¹⁶⁹ It could be used by

¹⁶³ *Id.* at 1.

¹⁶⁴ *Id.*

¹⁶⁵ *Id.* at 3 (indicating that the “values are based on the average [SCC] from three integrated assessment models, at discount rates of 5, 3, and 2.5 percent . . . [A] fourth value [was estimated based on] the 95th percentile of the [SCC] from all three models at a 3 percent discount rate, and is intended to represent the potential for higher-than-average damages”).

¹⁶⁶ *Id.* at 1 (stating that the SCC “should increase over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater levels of climate change”).

¹⁶⁷ Interagency Working Group on Social Cost of Carbon, *supra* note 161, at 12.

¹⁶⁸ EPA, *supra* note 162, at 1; *see also* Ctr. for Biological Diversity v. Nat’l Hwy. Transp. Safety Bd., 538 F.3d 1172 (9th Cir. 2008) (remanding environmental review and requiring agency to estimate

NYISO to set the carbon price to be incorporated into bids in the wholesale energy market. This would provide certainty for market participants, as the SCC is a robust metric, developed using technical models, with input from multiple government departments and the public. Recognizing this, in the context of ISO-NE's IMAPP stakeholder process, electric utility Exelon Corporation has recommended use of the SCC as the touchstone for pricing carbon in energy markets.¹⁷⁰

Despite this support, it is worth noting that the SCC is not universally accepted.¹⁷¹ Use of the SCC to price carbon in wholesale energy markets is likely to be opposed by some industry and other groups on the basis that it does not merely reflect the costs climate change imposes on electric grid operations but also includes various other costs (e.g., to the agricultural sector). Those costs are, however, an externality of electricity generation. As we explain in part 7.1.1 below, internalizing those external costs is necessary to enhance competition in wholesale electricity markets and ensure they operate effectively, to produce just and reasonable rates.

The SCC arguably provides the best metric for pricing the external costs of electricity generation's carbon dioxide emissions. The lowest SCC, calculated using a five percent discount rate, is consistent with the carbon prices currently used elsewhere in the electricity sector. For example:

cost imposed by GHG emissions); *Zero Zone Inc. v. U.S. Dept. of Energy*, 832 F.3d 654 (7th Cir. 2016) (upholding agency's use of social cost of carbon in cost-benefit analysis).

¹⁶⁹ See, e.g., *High Country Conservation Advocates v. U.S. Forest Serv.*, 52 F. Supp. 3d 1174 (D. Colo. 2014) (suggesting that the SCC could be used to estimate the costs of increased carbon dioxide emissions in environmental reviews under the National Environmental Policy Act). See also Sarah E. Light, *NEPA's Footprint: Information Disclosure as a Quasi-Carbon Tax on Agencies*, 87 TUL. L. REV. 511, 545-546 (noting that the EPA has encouraged federal agencies to use the SCC in environmental reviews under the National Environmental Policy Act); Michael Burger & Jessica Wentz, *Downstream and Upstream Greenhouse Gas Emissions: The Proper Scope of NEPA Review*, 41 HARV. ENVTL. L. REV. (forthcoming, 2017), <https://perma.cc/Z4K8-TJYV> (discussing the possibility of using the SCC in environmental reviews).

¹⁷⁰ Exelon Corporation, *Using Carbon Pricing in Dispatch to Meet the IMAPP Process Goals* (Aug. 30, 2016), <https://perma.cc/6RJQ-Q9K3>.

¹⁷¹ For a discussion of opposition to the SCC, see Bruce Lieberman, *Social Cost of Carbon: A Continuing Little-Told Story*, YALE CLIMATE CONNECTIONS (Sep. 12, 2013), <https://perma.cc/C49E-8Z47>. See also David Malakoff et al., *Trump Team Targets Changes to Key Metric that Calculates Social Cost of Carbon*, Science Insider (Dec. 16, 2016), <https://perma.cc/PKM5-6BVM>.

- It is below the implicit carbon price used by the EIA in calculating the levelized cost of electricity (“LCOE”). The LCOE reflects the per KWh cost of building and operating an electric generating plant, over an assumed financial life and duty cycle, taking into account capital, operation, maintenance, and financing costs.¹⁷² When calculating the LCOE, the EIA includes a three percent cost of capital adder for carbon intensive generating units, such as those using coal.¹⁷³ The impact of this is, according to the EIA, “similar to that of an emissions fee of \$15 per metric ton of carbon dioxide.”¹⁷⁴
- It is in line with the carbon price implicit in California’s cap-and-trade program.¹⁷⁵ As part of the cap-and-trade program, California has adopted an allowance auction system, with a minimum or “reserve” price, which functions as a minimum carbon fee. That fee was \$12.73 in 2016¹⁷⁶ and will rise \$13.57 in 2017.¹⁷⁷
- It is in line with, and in some cases less than, the carbon prices used internally by electric utilities. A number of utilities use a carbon price, for example, in their integrated resource planning processes. These include Xcel Energy Inc. which uses prices in the range of \$9 to \$34 per ton, Sempra Energy which uses a price of \$13 per ton, NiSource Inc. which uses a price of \$20 per ton, and Ameren Corporation which uses prices in the range of \$23 to \$54 per ton.¹⁷⁸

¹⁷² EIA, LEVELIZED COST & LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK (2016), <https://perma.cc/CS5S-83MA>

¹⁷³ The EIA asserts that the adder is necessary as “[b]ecause regulators and the investment community have continued to push energy companies to invest in technologies that are less greenhouse gas-intensive, there is considerable financial risk associated with major investments in long-lived power plants with a relatively higher rate of carbon dioxide emissions.” *See Id.* at 3.

¹⁷⁴ EIA, LEVELIZED COST & LEVELIZED AVOIDED COST OF NEW GENERATION RESOURCES IN THE ANNUAL ENERGY OUTLOOK 3 (2014), <https://perma.cc/L8SK-CKEQ>.

¹⁷⁵ *See supra* part 4.4.3.

¹⁷⁶ CALIFORNIA AIR RESOURCES BOARD, CALIFORNIA CAP-AND-TRADE PROGRAM AND QUÉBEC CAP-AND-TRADE SYSTEM: 2016 ANNUAL AUCTION RESERVE PRICE NOTICE (2015), <https://perma.cc/NC69-2SQW>.

¹⁷⁷ CALIFORNIA AIR RESOURCES BOARD, CALIFORNIA CAP-AND-TRADE PROGRAM AND QUÉBEC CAP-AND-TRADE SYSTEM: 2017 ANNUAL AUCTION RESERVE PRICE NOTICE (2016), <https://perma.cc/7TG7-A57V>.

¹⁷⁸ CDP, PUTTING A PRICE ON RISK: CARBON PRICING IN THE CORPORATE WORLD 62 (2015), <https://perma.cc/KXU4-AHU4>.

Given the above, NYISO may elect to use the lowest SCC, calculated using a discount rate of five percent, so as to mitigate cost impacts. That would result in an initial carbon price of \$12.82.¹⁷⁹

6.2 Carbon Price Adjustment

Economists generally agree that carbon prices should rise over time to reflect the fact that, as more carbon accumulates in the atmosphere, the incremental damage caused by one additional ton increases.¹⁸⁰ Consistent with this view, the SCC rises steadily from \$11 in 2015 to \$21 in 2040, and \$26 in 2050 (see Table 1 above).

At the time of establishing a carbon pricing scheme, NYISO should adopt procedures, specifying when and how price adjustments will be made. Ideally, to maximize certainty and predictability for the private sector, adjustments should be made at pre-defined intervals. NYISO could, for example, adjust prices every five years in line with the SCC. Assuming NYISO elects to use the lowest SCC (i.e., calculated using a five percent discount rate), this would result in a modest increase in carbon prices over the next two decades, mitigating the impact on costs.

6.3 Interaction with Other Carbon Prices

6.3.1 Interaction with RGGI

Some electric generators bidding into NYISO markets are already subject to carbon pricing through RGGI. It is important that any NYISO carbon pricing scheme avoid requiring generators—directly or indirectly—to pay twice for the same emissions (i.e., once to comply with the NYISO MST and once to comply with RGGI). The RGGI price should, therefore, be deducted from whatever carbon price NYISO adds to covered generators' bids. The CES, which confronts the same problem when deriving a ZEC price, solves it by subtracting two values from the SCC. The first is a fixed projection of the RGGI price, borrowed from NYISO's CARIS model, which

¹⁷⁹ The 2015 SCC value, calculated using a 5% discount rate, is \$11 in 2007. After adjusting for inflation, that is equivalent to \$12.82 in 2016 dollars.

¹⁸⁰ See, e.g., Joseph E. Aldy & Robert N. Stavins, *The Promise and Problems of Pricing Carbon: Theory and Experience*, 21 J. ENV'T & DEV. 152, 155 (2012).

anticipates patterns of and costs arising from transmission grid congestion.¹⁸¹ The second value is a hybrid of independent forecasts of NYISO's energy and capacity markets whose projections capture anticipated changes to RGGI's carbon price.¹⁸²

6.3.2 Interaction with New York's CES

FERC has determined that it does not have jurisdiction over markets for RECs unbundled from markets for energy or capacity.¹⁸³ Thus Tiers 1 and 2 of New York's CES can operate in parallel with a wholesale market carbon price without legal consequence. Tier 3, however, establishes a ZEC price that is both derived from the SCC and constrained by NYISO energy market prices. Some of the litigants in the current dispute over New York's CES argue that these features make the ZEC price potentially subject to FERC's jurisdiction (see part 5.2 above) as well as logically duplicative of any carbon price based on the SCC. Consequently, if NYISO's carbon price were to derive from the SCC, then NYISO and the NYPSC would have to decide which price would accommodate or displace the other. Otherwise, both would be premised on correcting electricity prices to better reflect the value of avoiding the adverse effects of climate change but would actually impose costs that, in combination, exceed the value they are meant to approximate, namely a version of the SCC. This logical failing would be legally problematic as well because it would belie the argument that the carbon pricing scheme improves wholesale price formation by more accurately incorporating costs that are relevant but were heretofore ignored (see part 7).

Ultimately, either accommodating or displacing Tier 3 of the CES would mean applying a carbon price more or less uniformly to all the generation sources subject to NYISO's tariff. The key differences between the two approaches would relate to implementation. Accommodation would mean crafting a new mechanism that alters non-nuclear generator bid prices, operates alongside the CES, and leaves the ZEC prices paid to three nuclear generators undisturbed. Displacement would mean eliminating Tier 3 and simply modifying the bid prices of all generators based on the

¹⁸¹ CES Order at 131, 135–36.

¹⁸² Those forecasts pertain to Zone A, where no nuclear facilities are located. This lowers ZEC prices at times when electricity prices are expected to increase.

¹⁸³ WSPP, Inc., 139 FERC ¶ 61,061 P 7 (Apr. 20, 2012) (clarifying that FERC has jurisdiction over bundled REC and energy transactions, but not over unbundled REC-only transactions).

carbon content of their fuel. Practically, displacement would be far simpler; politically, both are fraught.

6.4 Likely Effect on Wholesale Electricity Prices

Adoption of a carbon pricing scheme by NYISO will, in the short run, likely lead to an increase in the market clearing price of electricity. The amount of that increase will depend on the carbon dioxide emissions profile of the marginal generator since, as described above, prices will be set equal to that generator's bid plus a carbon fee based on its emissions. Average emissions from various classes of generating units are shown in Table 2. Based on those averages and assuming a carbon price of \$12.82,¹⁸⁴ the table shows the carbon fee for each class of generator.

Table 2: Estimated Carbon Fee for Fossil Fuel Generators

Generating Resource	Average Emissions Rate ¹⁸⁵ (per MWh)	Carbon Fee ¹⁸⁶ (per MWh)
Coal – Lignite	1.09 tons	\$13.97
Coal – Subbituminous	1.08 tons	\$13.85
Coal – Bituminous	1.04 tons	\$13.33
Oil – Residual (No. 6)	0.88 tons	\$11.28
Oil – Residual (No. 2)	0.82 tons	\$10.51
Natural Gas	0.61 tons	\$7.82

Currently, in NYISO markets, natural gas-fired resources are the marginal source of supply in most intervals.¹⁸⁷ It is unclear whether that will remain the case after introduction of a carbon

¹⁸⁴ See *supra* part 6.1.

¹⁸⁵ EIA, *How Much Carbon Dioxide is Produced per Kilowatt Hour when Generating Electricity with Fossil Fuels?* FREQUENTLY ASKED QUESTIONS, <https://perma.cc/ZN2K-3AT7> (last updated Feb. 29, 2016) (estimating the number of pounds of carbon dioxide produced per KWh of electricity generated, based on the average heat rates for steam electric generators in 2014).

¹⁸⁶ Calculated assuming a carbon price of \$12.82 per ton.

¹⁸⁷ DAVID B. PATTON ET AL., POTOMAC ECONOMICS, 2015 STATE OF THE MARKET REPORT FOR NEW YORK ISO MARKETS (2016), <https://perma.cc/72JG-DBFV> (indicating that natural gas-fired resources were the marginal source of supply in 67% of intervals).

pricing scheme. We anticipate some re-ordering of resources, but cannot determine exactly how the supply mix will change, and/or whether gas will remain at the margin. This will depend on a number of factors, including each generator's cost and emissions profile, as shown in the simplified example above. Further complicating matters, there will likely also be a demand response, which affects dispatch. For example, if higher prices reduce electricity demand, fewer generating units may need to be dispatched, leading to a change in the marginal unit.¹⁸⁸

In intervals when natural gas is at the margin, the market-clearing price would increase by around \$8, depending on the marginal generator's actual emissions. Should coal be at the margin, the market clearing price increase would be around \$14. Each generator would receive the market clearing price less their carbon fee. Thus, as the carbon fee is highest for fossil fuel generators, there would be an incentive to increase investment in renewable and other low-carbon generation. In the long-run, the market clearing price may decrease as the generating fleet becomes less carbon-intensive and low- and zero-emitting generators are increasingly on the margin. Such a decrease could be partially or wholly offset by increases to the carbon price. Such increases could cause the market clearing price to rise over time.

6.5 Options for Re-distributing Revenues

To offset increased wholesale electricity prices, revenues generated through the carbon pricing scheme should be reimbursed to LSEs and other buyers in an equitable manner. This could be achieved in a number of ways. One option is to require LSEs to pay the full market-clearing price, including the amount of any carbon fee. Each generator would receive that price, less their unit specific carbon fee, which would be retained by NYISO. The retained funds could then be refunded to LSEs in an equitable manner. States could direct LSEs to use the refunded amount to mitigate end-customer bill impacts or fund state policy goals (e.g., energy efficiency investments). Studies suggest that, where the refunds are passed through to customers, any increase in retail bills is likely to be minimal. By way of example, Exelon estimated an increase in retail bills of just one to

¹⁸⁸ For a discussion of this issue, see Jos Sijm et al., *CO₂ Cost Pass-Through and Windfall Profits in the Power Sector*, 6 CLIMATE POL'Y 49 (2006).

two percent, assuming a carbon price of \$20 per ton.¹⁸⁹ Another study for the Clean Air Task Force estimated that, with a carbon price of \$34 per ton, bills would increase by four percent.¹⁹⁰

Ideally, refunds to LSEs should not be tied to their specific purchases in energy markets, so as to avoid dampening any demand response.¹⁹¹ NYISO could, for example, provide periodic refunds based on each LSE's share of total load during the period. Refunds would not be tied to LSEs' actual share of carbon fees, meaning that all LSEs would receive the same amount per MWh of electricity purchased, regardless of whether purchases are made during times of low or high fees.

Similar refund schemes have been adopted by ISO/RTOs in other circumstances. By way of example, since 2007, PJM has included the marginal cost of transmission line losses in energy market prices.¹⁹² As marginal losses rise exponentially with transmission system flows, they exceed average losses, resulting in PJM over-collecting revenues relative to costs.¹⁹³ PJM refunds the excess to buyers on a monthly basis, in proportion to each buyer's MW usage, rather than its actual contribution to the surplus funds.¹⁹⁴ A similar marginal loss collection and refund scheme is used by CAISO.¹⁹⁵ Both the CAISO and PJM schemes have been approved by FERC; FERC's approval of

¹⁸⁹ Assuming the revenues from the carbon price were applied to retail bill relief programs. See Comments of Exelon Corporation on U.S. Environmental Protection Agency's Proposed Carbon Pollution Emission Guidelines for Existing Stationary Sources (Dec. 1, 2014), <https://perma.cc/EK3C-3DPP>.

¹⁹⁰ BRUCE PHILLIPS, THE NORTHBRIDGE GROUP, ALTERNATIVE APPROACHES FOR REGULATING GREENHOUSE GAS EMISSIONS FROM EXISTING POWER PLANTS UNDER THE CLEAN AIR ACT: PRACTICAL PATHWAYS TO MEANINGFUL REDUCTIONS (2014), <https://perma.cc/2QXX-MP33>.

¹⁹¹ See *supra* part 6.4.

¹⁹² Atlantic City Electric Co. v. PJM Interconnection, 115 FERC ¶ 61,132 (2006). For a discussion of this decision and its relevance to carbon pricing in wholesale electricity markets, see STEVEN WEISSMAN & ROMANY WEBB, ADDRESSING CLIMATE CHANGE WITHOUT LEGISLATION: HOW THE FEDERAL ENERGY REGULATORY COMMISSION CAN USE ITS EXISTING LEGAL AUTHORITY TO REDUCE GREENHOUSE GAS EMISSIONS AND INCREASE CLEAN ENERGY USE 10-11 (2014), <https://perma.cc/LFV6-DZ3K>.

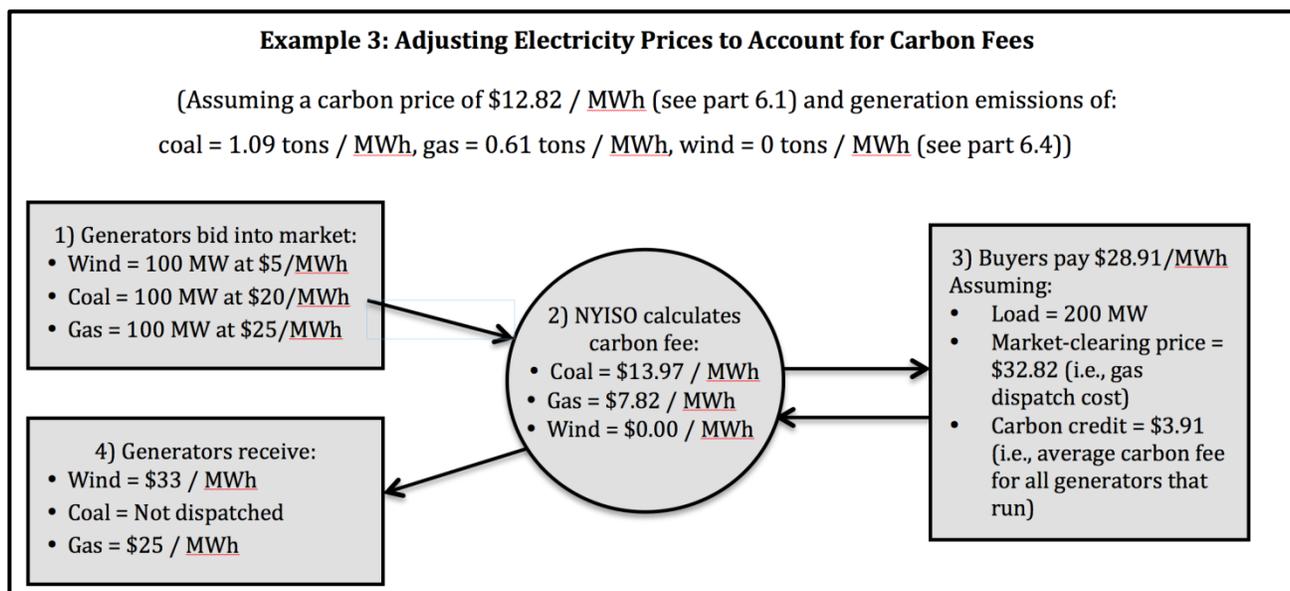
¹⁹³ Atlantic City Electric Co., 115 FERC ¶ 61,132 at P 4-5.

¹⁹⁴ Atlantic City Electric Co., v. PJM Interconnection, 117 FERC ¶ 61,169 (2006).

¹⁹⁵ California Independent System Operator, 116 FERC ¶ 61,274 (2006), *order on reh'g*, 119 FERC ¶ 61,076 (2007).

the PJM scheme has been upheld by the U.S. Court of Appeals for the District of Columbia Circuit.¹⁹⁶

Some market participants have suggested that, rather than collecting and then refunding carbon fees, ISO/RTOs should simply adjust the electricity prices paid by LSEs and other buyers. NYISO could, for example, set a buyer price equal to the market-clearing price less the average carbon fee for all dispatched generators (see example 3 below). This approach would dampen the demand response to the carbon pricing scheme, as LSEs would face a lower price, compared to the situation in which the adder is collected by NYISO.



6.6 Monitoring and Reporting

To successfully implement a carbon pricing scheme, data will be required on each generator's carbon dioxide emissions, so as to calculate the carbon fee to be added to its bids. The required data is already recorded in the New York Generator Attribute Tracking System ("NYGATS"). Maintained by NYSERDA, NYGATS is used to track the environmental attributes of electricity generated within New York, as well as that imported to the state. For each MWh of

¹⁹⁶ Black Oak Energy, LLC v. Fed. Energy Regulatory Comm'n, U.S. App. LEXIS 16201 (D.C. Cir. 2013). FERC's approval of the CAISO scheme was not appealed to the courts.

electricity, NYGATS records the generation source (whether in or out of state) and key characteristics of that source, including its carbon dioxide emissions rate. The emissions data is entered by NYISO, based on reports filed by generators participating in its market.

7. DOES THE LAW PERMIT NYISO TO PRICE CARBON?

Any NYISO carbon pricing scheme would be subject to review by FERC. As explained in part 3.3 above, under the FPA, FERC is responsible for overseeing wholesale electricity rates to ensure they are just, reasonable, and not unduly discriminatory or preferential. The FPA requires public utilities, including ISO/RTOs, to submit proposed changes to their rates or practices affecting rates to FERC.¹⁹⁷

FERC has traditionally shown great deference to ISO/RTOs to formulate market rules as they see fit.¹⁹⁸ FERC may approve an amended NYISO tariff, establishing new market rules, without finding that the existing tariff is deficient or that the amended tariff is somehow superior.¹⁹⁹ The applicable standard requires only that the amended tariff be just, reasonable, and not unduly discriminatory or preferential.

7.1 Including a Carbon Price in Wholesale Electricity Rates is Just and Reasonable

This sub-part presents two distinct lines of argument supporting the conclusion that carbon pricing in NYISO markets is just and reasonable. The first is the bolder of the two and builds on the premise that FERC has wide latitude to authorize a NYISO proposal aimed at improving the functioning of its wholesale markets. The second resembles arguments made elsewhere for adopting a wholesale carbon price because doing so reflects and rationalizes state public policy. As noted in the introduction, though these arguments are distinct from one another, they are not mutually exclusive. Importantly, these arguments are intended to justify inclusion of a carbon

¹⁹⁷ 16 U.S.C. § 824d(d).

¹⁹⁸ Michael H. Dworkin & Rachel Aslin Goldwasser, *Ensuring Consideration of the Public Interest in the Governance and Accountability of Regional Transmission Organizations*, 28 ENERGY L.J. 543, 555 (2007).

¹⁹⁹ 16 U.S.C. § 824(d).

price of some sort in NYISO's tariff and do not address the level at which any such price should be set. That issue is discussed in part 7.1.3 below.

7.1.1 Argument 1: Improving the Functioning of Wholesale Markets Administered by NYISO

Argument 1(a): A carbon price would enhance competition in NYISO markets. As discussed in part 3.3 above, FERC considers rates to be just and reasonable if they are set in well-functioning, competitive wholesale energy markets. FERC regulates markets to mitigate the exercise of market power and otherwise enhance competition, viewing such regulatory intervention as “integral to . . . fulfilling its statutory mandate under the FPA to ensure supplies of electric energy at just [and] reasonable” prices.²⁰⁰ FERC put this premise to the test in 2011 when, in Order 745,²⁰¹ it required ISO/RTOs to pay the full LMP to qualifying demand response resources on the grounds that promoting “meaningful demand-side participation” in wholesale markets would increase competition in those markets with salutary effects on prices.²⁰² The Supreme Court ultimately endorsed FERC's logic in *FERC v. Electric Power Supply Association* (“EPSA”).²⁰³

In upholding Order 745, the court in *EPSA* noted that FERC “undertakes to ensure just and reasonable wholesale rates by enhancing competition – attempting . . . to break down regulatory and economic barriers that hinder a free market in wholesale electricity.”²⁰⁴ The court emphasized that Order 745 is intended “to improve how [the wholesale energy] market runs.”²⁰⁵ According to the court, FERC's “justifications for regulating demand response are all about, and only about improving the wholesale market . . . FERC explained that demand response participation could create a well-functioning competitive” market with reduced rates and enhanced reliability.²⁰⁶

The decision in *EPSA* suggests that FERC has broad authority to promote competition in wholesale markets as a means of ensuring just and reasonable rates. Based on *EPSA*, at least two

²⁰⁰ Order No. 745, *supra* note 96, at 6.

²⁰¹ *Id.*

²⁰² *Id.* at 1.

²⁰³ *EPSA*, 136 S. Ct. 760 (2015).

²⁰⁴ *Id.* at 768.

²⁰⁵ *Id.* at 776.

²⁰⁶ *Id.* at 776–77.

commentators have suggested that FERC could approve an ISO/RTO-proposed carbon price as just and reasonable, so long as evidence demonstrated that the adder would enhance competition.²⁰⁷ Peskoe, who makes this argument in relation to ISO-NE, emphasizes that FERC's approval "may be on more solid legal ground" if the adder is designed to achieve specific competitive outcomes which are independent of the environmental harm caused by carbon dioxide emissions.²⁰⁸ Thus Peskoe stops short of endorsing what has been called "social-cost dispatch" — the adjustment of market based rates so that they reflect social costs rather than private ones.²⁰⁹

Weissman and Webb, writing before the *EPISA* decision, argued that including the social cost of carbon dioxide emissions in rates is *necessary* to enhance competition in wholesale markets:

[L]ess-polluting generators are placed at a competitive disadvantage when more-polluting generators can mask the true cost of power by ignoring externalities The existence of environmental externalities represents [a] kind of market failure to which FERC could . . . respond by adjusting the bid price [In doing so, FERC's] objective would be to stimulate the development of generating units that will impose the lowest cost on society and remove [a] market distortion — the ability of some generators to undercut their competitors by escaping responsibility for their environmental costs.²¹⁰

This reasoning takes the characterization of environmental externalities as being outside of FERC's remit and stands it on its head. By Weissman and Webb's logic, ignoring environmental externalities means giving some market participants an unfair competitive advantage over others and thereby impairing market competitiveness.²¹¹ This view sees an analogy between

²⁰⁷ See, e.g., Ari Peskoe, *Integrating Markets and Public Policy in New England* 9 (Oct. 27, 2016), <https://perma.cc/MWY8-FQDK> (stating that FERC could approve a carbon adder if it "can conclude that there is adequate support in the record that [the] proposal furthers that goal" of enhancing competition); Joel B. Eisen, *FERC's Expansive Authority to Transform the Electric Grid*, 49 U. CAL. DAVIS L. REV. 1783, 1788 (2016) ("[FERC] can even take an 'environmental' action — such as addressing climate change through a carbon adder — if it has a direct relationship to wholesale rates.").

²⁰⁸ Peskoe, *supra* note 207, at 28.

²⁰⁹ Bateman & Tripp, *supra* note 125, at 330.

²¹⁰ WEISSMAN & WEBB, *supra* note 192, at 10 & 12.

²¹¹ See Bateman & Tripp, *supra* note 125, at 304 ("by not incorporating GHG externalities into its rate regulation, FERC influences decisions about what generation should be built just as much as it would by incorporating these externalities. The effect of its exclusion of the externalities is simply

compensating emitting- and non-emitting generators at the *same* rate and compensating generation and demand response at *different* rates. FERC Order 745 eliminated the latter distinction on the grounds that inadequate compensation inhibited wholesale market participation by demand response resources, which in turn kept average rates higher than necessary and, more generally, reduced competition in wholesale energy markets. In the case of a carbon price, FERC would be acting to facilitate the participation of low-carbon generators that, like demand response resources, are inadequately compensated for the services they provide because rates do not reflect their zero-emission attributes. Adopting a carbon price would ensure that rates more accurately reflect the value that low- and high-carbon sources of electricity deliver and thus level the competitive playing field.

The playing field is particularly skewed in NYISO markets, which are affected not only by the current failure to internalize carbon externalities at the wholesale level, but also by state policies adopted in more or less direct response to that failure. The policies, described in part 5 above, effectively attach a value to generators' carbon-related attributes. They do not, however, apply equally to all generators with the same attributes. Just seventy-six of New York's roughly 170 fossil fuel generators have their carbon dioxide emissions priced through RGGI. Some low-carbon generators that operate renewable energy sources are compensated for their zero-emission attributes through REC sales. Such compensation is not, however, consistently available to non-renewable low-carbon generators. Finally, three, but not all four, of the state's nuclear generators receive compensation from ZEC sales which is not available to renewable generators.

Due to their partial application, state policies provide only incomplete and inchoate remedies for the market failure described above and arguably further distort the market, thereby impairing effective competition among wholesale buyers and sellers. The policies give some market participants a competitive advantage over others with the same attributes. RGGI, for example, increases the costs faced by large fossil fuel generators due to the need to purchase emission allowances. Those generators are, therefore, forced to bid into the market at higher prices. Smaller fossil fuel generators (i.e., that are not subject to RGGI) can, however, continue making bids that

to give GHG-intensive generation, such as coal, an advantage vis-à-vis cleaner energy, such as wind.”).

exclude the cost of emissions and thus undercut their competitors. Similarly, as a result of the CES, nuclear power plants can undercut fossil fuel and other generators. The CES increases the return nuclear power plants receive for electricity sold in wholesale markets, creating an incentive for them to reduce their bids (i.e., to ensure they are dispatched) and thereby putting downward pressure on market prices. This is likely to affect the financial viability of other generators, both low-and high-carbon, impeding their ongoing participation in wholesale markets.

We note that some commentators have disputed FERC's authority to adjust wholesale market prices to internalize the external costs of carbon dioxide emissions.²¹² Moot, for example, has argued that such costs are fundamentally extrinsic to wholesale markets and thus beyond FERC's legal domain.²¹³ He states:

FERC can remove barriers to participation by renewable resources in wholesale power markets . . . if those barriers constitute an undue preference. That preference must relate to a matter within FERC's jurisdiction, however, not a matter committed to the jurisdiction of other governmental bodies. Just as the FERC cannot remedy perceived inequities in the tax code by withholding wholesale market revenues from firms allegedly taking advantage of tax loopholes, it cannot counteract Congress' failure to enact cap-and-trade legislation by creating its own program through a wholesale market design change.²¹⁴

In our view, however, FERC approval of a NYISO carbon price would not amount to an extension of environmental policy by other means. Rather, it would be a logical application of the principles that have long guided FERC's management of wholesale markets. While we agree with Moot that neither the FPA nor other federal legislation expressly authorizes FERC to address emissions, that would not be FERC's primary purpose in approving a carbon price. FERC's purpose would be to enhance wholesale market operations and promote competition, much as it has done in other instances where it has lacked express legislative sanction but has proceeded anyway.²¹⁵

Argument 1(b): A carbon pricing scheme would ensure proper wholesale price formation. In considering FERC's authority to approve a carbon pricing scheme following *EPSA*, it is important

²¹² See e.g. Moot, *supra* note 4.

²¹³ *Id.* at 358 – 361.

²¹⁴ *Id.* at 361.

²¹⁵ See *supra* part 2.1.

to bear in mind the features of Order 745. Most notably, as the Supreme Court observed, the order “is all about” reducing wholesale electricity prices.²¹⁶ In contrast, a carbon pricing scheme is likely to increase *wholesale electricity prices*, at least in the short-run.²¹⁷ In the long-run, however, prices should fall as the generating fleet becomes less carbon intensive.²¹⁸ In contrast, from the start, the *costs* of generation will likely fall. While electricity prices and costs are often assumed to be equivalent,²¹⁹ in fact, costs currently exceed prices due to the presence of externalities. These externalities reflect a cost to society—one that, in our view, must be incorporated into prices if they are to provide clear signals to market participants and investors.

FERC has recently emphasized the importance of proper price formation to, among other things, maximize market surplus and incentivize investment.²²⁰ According to FERC Commissioner Cheryl LaFleur, to achieve these objectives, prices must “reflect the true cost of reliable operations.”²²¹ The near-term effects of climate change—warmer ambient temperatures, heat waves, less reliable access to water, and more frequent and intense storms—have clear import for system reliability. These effects will impair generation and transmission facility efficiency,²²²

²¹⁶ *EPSA*, 136 S. Ct. at 774. As noted above, Order 745 aims to promote the participation of demand response resources in wholesale markets by compensating them at the full LMP. Such compensation is, however, only required where resources pass a net benefits test indicating that their dispatch will result in lower wholesale prices (i.e., compared to if all load was met with generation).

²¹⁷ See *supra* section 6.4.

²¹⁸ *Id.*

²¹⁹ In *EPSA* the court uses the terms “price” and “cost” interchangeably. Compare *EPSA*, 136 S. Ct. at 778 (indicating that “wholesale market operators accept demand response bids only if those offers lower the wholesale *price*” (emphasis added)) and 782 (stating operators will accept a bid “so long as that bid can satisfy a “net benefits test” – meaning that it is sure to bring down *costs*” (emphasis added)).

²²⁰ FERC Notice Inviting Post-Technical Workshop Comments (Jan. 16, 2015), <https://perma.cc/9PMZ-NA5B>.

²²¹ Transcript of Hearing: Price Formation in Energy and Auxiliary Services Markets Operated by Regional Transmission Organizations and Independent System Operators (Dec. 9, 2014), <https://perma.cc/YAM8-L6FE>.

²²² See generally U.S. DEPARTMENT OF ENERGY, U.S. ENERGY SECTOR VULNERABILITIES TO CLIMATE CHANGE AND EXTREME WEATHER 10 (2013), <https://perma.cc/62TQ-VUCN> (indicating that, in natural gas and coal units, “heat is used to produce high-pressure steam, which is expanded over a

undermining reliability and creating costs, which must be reflected in prices so as to provide correct incentives for investment in new facilities. Put another way: climate change is imposing costs on the electric grid and its end users that wholesale markets currently interpret as noise rather than signal; carbon pricing would serve to translate that signal into price effects and thereby more accurately reflect the value that high- and low-carbon sources of electricity deliver.

FERC has recently taken steps to ensure that market prices more fully account for the cost of generation. In Order 825, for example, FERC directed market operators to implement various reforms aimed at ensuring prices more accurately reflect energy and reserve shortages²²³ so that generators “are compensated for the value of the service that they provide” and thus face the correct incentives to invest in enhancing reliability.²²⁴ While Order 825 relates to the pricing of features endogenous to wholesale markets, FERC has also dealt with exogenous features in the past. FERC has previously adjusted wholesale market prices to achieve public policy objectives such as reduced transmission line losses.²²⁵ In 2006 FERC ordered PJM to include an uplift charge - equal to the marginal cost of line losses—in wholesale prices to cover the cost of energy lost during transmission. According to Weissman and Webb:

turbine to produce electricity. The driving force for the process is the phase change of the steam to a liquid following the turbine . . . A vacuum is created in the condensation process that draws the steam over the turbine. This low pressure is critical to the thermodynamic efficiency of the process. Increased backpressure will lower the efficiency of the generation process. Increases in ambient air temperatures and cooling water temperatures will increase steam condensate temperatures and turbine backpressure, reducing power generation efficiency.”). *See also* SOFIA AIVALIOTI, SABIN CTR. FOR CLIMATE CHANGE LAW, ELECTRICITY SECTOR ADAPTATION TO HEAT WAVES (2015), <https://perma.cc/93FG-8NHF>; Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal (Feb. 21, 2014), <https://perma.cc/RCU5-ZKQS>.

²²³ FERC noted that “some RTOs/ISOs currently restrict the use of shortage pricing to certain causes of shortages, or some RTOs/ISOs requires a shortage to exist for a minimum amount of time before triggering shortage pricing.” *See* Order No. 825, *supra* note 98, at 58. FERC determined that “existing shortage pricing triggers that do not invoke shortage pricing when there is a shortage (regardless of duration or cause) are unjust and unreasonable.” *Id.* at 60. FERC therefore required “each RTO/ISO to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated.” *Id.* at 90.

²²⁴ *Id.* at 7.

²²⁵ For a discussion of this issue, see WEISSMAN & WEBB, *supra* note 192, at 10-11.

FERC's decision to require marginal loss pricing was made on policy grounds and aimed to ensure that prices provide the strongest signal possible to encourage more efficient use of the transmission system . . . FERC emphasized that use of this methodology would reduce electricity supply costs and thereby increase electricity market efficiency [stating]: "by changing to the marginal losses method, PJM would change the way that it dispatches generators by considering the effects of [transmission line] losses. As a result . . . the total cost of meeting load would be reduced" (internal citations omitted).²²⁶

Just as line losses create a burden for buyers and sellers of electricity, justifying market rule adjustments, so too do carbon dioxide emissions and associated climate change. Both lead to reduced system reliability and thus increased costs for market participants. Adopting a carbon price would internalize the external costs of emissions, ensuring that they are taken into account by market operators when dispatching generators, and thereby causing electricity demand to be served by the lowest *cost* resources.

7.1.2 Argument 2: Ensuring orderly development of the electric system

Argument 2(a): Wholesale carbon pricing reflective of diverse state policies would, in the short-run, harmonize those policies. As discussed in part 3.3, in exercising its authority to set just and reasonable rates, FERC must balance the interests of suppliers and customers.²²⁷ FERC must also ensure protection of the public interest.²²⁸ This does not, however, give FERC "a broad license to promote the general public welfare."²²⁹ Rather, as the Supreme Court has observed, it "is a charge to promote the orderly production of plentiful supplies of electric energy" at reasonable prices.²³⁰ Achieving this goal in the age of climate change means ensuring that prices provide

²²⁶ Weissman & Webb, *supra* note 192, at 10-11.

²²⁷ Hope Nat. Gas Co., 320 U.S. at 603.

²²⁸ See, e.g., Fed. Power Comm'n v. Sierra Pacific Power Co., 350 U.S. 348, 355 (1956) (declaring that "the purpose of the power given the Commission by § 206(a) [i.e., to set just and reasonable rates] is the protection of the public interest").

²²⁹ Nat'l Ass'n for the Advancement of Colored People v. Fed. Power Comm'n, 425 U.S. 662, 669 (1972).

²³⁰ *Id.*

appropriate signals for investment in low-carbon generation consistent with state policy.²³¹ In the short run, this means rationalizing the current patchwork of carbon-related electricity pricing policies in New York. In the long run, it means ensuring that market participants align their plans with existing and *foreseeable* future legal requirements.²³²

Some but not all NYISO market participants are subject to state policies aimed at supporting the transition to low-carbon electricity generation. As discussed in part 7.1.1 above, the patchwork of state policies provides partial coverage of New York generators with respect to carbon emissions. It also imposes diverse price levels on those emissions or their absence: REC values derive from an independent market whose participants must comply with the state's RPS; ZEC values derive from a formula derived from the SCC; and RGGI allowance prices derive from an interstate allowance-trading market. As of January 2017, REC purchasers paid \$21.16 per MWh,²³³ ZEC purchasers \$17.54 per MWh,²³⁴ and RGGI participants \$3.55 per short ton of carbon dioxide, which translates to about \$2.17/MWh for natural gas-fired generators and \$3.67 for bituminous coal-fired ones.²³⁵

Partial coverage and diverse pricing complicates and distorts the values transmitted via wholesale electricity markets to participants, thereby impairing efficient planning and investment. This situation is ripe for improvement via the sort of rationalization that a more uniformly applicable wholesale carbon price would provide.

Argument 2(b): Wholesale carbon pricing reflective of state-level public policy would improve long-run planning. A harmonizing wholesale carbon price would also help ensure orderly electric system development over the long-term. New York policy-makers responsible for the

²³¹ See generally Recommendations of the Task Force on Climate-related Financial Disclosures (Dec. 2016), <https://perma.cc/W45A-NH47> (characterizing categories of investment risk arising from climate change).

²³² See Peskoe, *supra* note 207, at 16–17, 24 (discussing FERC's authority to ground decisions in expectations about expected future policy choices).

²³³ New York State, Clean Energy Standard: REC and ZEC Purchases from NYSERDA, <https://perma.cc/QVC9-89VC> (last visited Jan. 30, 2017)

²³⁴ *Id.*

²³⁵ See EIA, Frequently Asked Questions: *How much carbon dioxide is produced per kilowatthour when generating electricity with fossil fuels?*, <https://perma.cc/7FPM-NYPU> (last updated Feb. 29, 2016) (indicating that natural gas emits, on average, 1.22 pounds of CO₂ per kWh, and bituminous coal emits 2.07).

electric grid have long recognized the need to mitigate climate change and have embodied that goal in a variety of policies. Achieving the state’s climate change mitigation goals, such as the 40 by 30 goal, will require replacing a significant volume of fossil-fueled generation with energy efficiency and zero-emitting resources, which will in turn require expanding transmission capacity and making changes to bulk power system operations. Planning must begin now if New York and NYISO are to minimize the impact of these changes on electric system reliability while ensuring continued availability of plentiful supplies of electricity at reasonable rates.

FERC has previously taken steps to improve electric system planning, including by adopting Order 1000, which requires Transmission Owners “ to develop a regional transmission plan that reflects the evaluation of whether alternative regional solutions may be more efficient or cost-effective” than local solutions.²³⁶ Specifically, Order 1000 requires Transmission Owners seeking to develop new transmission facilities to participate in a regional planning process, which:

- (1) considers “transmission needs driven by public policy requirements established by” enacted statutes or regulations,²³⁷ and allows for consideration of transmission needs driven by public policy objectives not codified in existing laws;²³⁸ and
- (2) gives “comparable consideration” to transmission and non-transmission alternatives—a category that includes storage, energy efficiency, distributed energy resources, and demand response.

Adoption of a NYISO carbon price reflective of state-level public policies would promote the same goals as Order 1000, albeit on different legal grounds. Specifically, it would embody New York’s policies with respect to climate change mitigation and adaptation, including those not yet codified, in a way that directly informs bulk power system planning—a potentially important

²³⁶ Order No. 1000, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities 136 FERC ¶ 61,051 (Jul. 21, 2011) [hereinafter Order No. 1000].

²³⁷ *Id.* at 9.

²³⁸ *Id.* at 168; see also Shelly Welton, *Non-Transmission Alternatives*, 39 HARV. ENVTL. L. REV. 457, 481–86 (2015) (describing examples of planning pursuant to Order 1000 that fail to realize that Order’s stated aims).

corrective, given the ambition of New York’s 40 by 30 goal²³⁹ and the fact that uncodified policies are often ignored by transmission operators in their planning processes.²⁴⁰

Similarly, a wholesale carbon price would also push in the same direction as Order 1000’s “comparable consideration” requirement. This requirement was intended to ensure that investments in transmission—which are always costly and long-lived—are not made before due consideration is given to potentially more efficient and cost-effective alternative approaches.²⁴¹ Despite this, however, regional transmission planning efforts still typically focus on how to develop transmission and largely or completely ignore the question of whether non-transmission alternatives might contribute to a more optimal solution, either by supplanting transmission facilities or enabling more cost-effective routes or combinations of transmission and alternatives.²⁴² The state’s “Reforming the Energy Vision” initiative, adopted to further progress towards the 40 by 30 goal, includes support for energy efficiency, distributed generation, and other non-transmission alternatives. The NYPSC is working to ensure that retail electricity markets operate in a way that is consistent with and furthers investment in these alternatives. A wholesale carbon

²³⁹ New York State Energy Planning Board, *The Energy to Lead: 2015 New York State Energy Plan* vol. 1, at 45 (2015), <https://perma.cc/Q8J5-QRE4> (stating that goal of energy efficiency reductions of 600 trillion BTU in buildings would mean a twenty-three percent reduction by 2030 from a 2012 baseline).

²⁴⁰ See, e.g., WEISSMAN & WEBB, *supra* note 192, at 36 (finding that “[w]hile some transmission operators have voluntarily elected to consider additional policy objectives not codified in existing laws and regulations, most have not”). But see, CDP, *supra* note 178, at 40 (indicating that some electric utilities have begun considering “the potential future policy and regulatory risk associated with carbon [dioxide] emissions” in their planning processes).

²⁴¹ Order No. 1000, *supra* note 236, at 38-50; see also Scott Hempling, ‘Non-Transmission Alternatives’: FERC’s ‘Comparable Consideration’ Needs Correction, ELEC. POL’Y 9 (May 2013), <https://perma.cc/SKR5-TY8S> (“It is not prudent for a public utility not to consider all feasible alternatives. The costs that emerge from an imprudent process—one that ignores alternatives—cannot be reasonable costs.”).

²⁴² Welton, *supra* note 238, at 481–86 (illustrating with examples how Order 1000 has failed to realize its stated aims); Interview of Allen Gleckner, Humphrey School of Public Affairs, Univ. of Minn., 10–11 (June 16, 2015), <https://perma.cc/LRT5-HPCB> (“a problem with transmission planning nation-wide is how non-transmission alternatives are looked at . . . Right now there are a few different wonky reasons why it’s not being fully looked at on a level playing field with the transmission proposals”).

price would reflect this purpose by pushing stakeholders to more thoroughly examine non-transmission alternatives.²⁴³

7.1.3 Carbon Prices Aligned to Arguments 1 and 2

Parts 7.1.1 and 7.1.2 above present various arguments in support of carbon pricing in NYISO . Design of the pricing scheme and the pricing level depends heavily on which of those arguments NYISO relies upon:

- *Argument 1(a)*, which emphasizes the need to internalize carbon externalities to improve wholesale market competitiveness, logically corresponds to a carbon price based on the SCC. As explained in part 6.1 the SCC is an approximation of the damage to social welfare resulting from carbon dioxide emissions. Its use would, therefore, ensure that the external costs of emissions from fossil fuel generation are reflected in electricity prices which, in our view, is necessary to level the playing field for non-fossil generators and thus improve the functioning of wholesale markets.
- *Argument 1(b)*, which focuses on the costs fossil fuel generation imposes on the electric system, e.g., in terms of reduced reliability, would not justify adoption of a carbon price based on the SCC. As the SCC is a measure of the economy-wide cost of carbon dioxide emissions, its use would overstate the reliability and other electric system costs of such emissions. We are not aware of an analysis that traces cost causation from generators to end-users, but we are confident that it could be done by examining carefully the effects on reliability and resiliency of particular fuel and facility types.²⁴⁴
- *Argument 2*, which emphasizes the need to improve short- and long-run electric system planning, would arguably justify use of a price derived from the SCC as the basis for a scheme that harmonized various state-level public policies. Underlying this argument is a concern that current and future state policies aimed at addressing climate change will necessitate a shift away from carbon-intensive generation. NYISO's adoption of a carbon pricing scheme derived

²⁴³ Cf. NYISO, Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets (Draft) (Aug. 1, 2016), <https://perma.cc/Y87U-UVBG>.

²⁴⁴ For a discussion of service reliability studies, see MICHAEL J. SULLIVAN ET AL., ERNEST ORLANDO LAWRENCE BERKELEY NATIONAL LABORATORY, UPDATED VALUE OF SERVICE RELIABILITY ESTIMATES FOR ELECTRIC UTILITY CUSTOMERS IN THE U.S. (2015), <https://perma.cc/6M6Y-6KDA>.

from the SCC, which is already a touchstone for New York public policy, would help ensure that market participants plan for that shift now.

7.2 A NYISO Carbon Price Would Not Be Unduly Discriminatory

FERC cannot approve a utility tariff that it finds to be unduly discriminatory in the sense of “grant[ing] any undue preference or advantage to any person or subject[ing] any person to any undue prejudice or disadvantage or . . . maintain[ing] any unreasonable difference in rates.”²⁴⁵ This was historically assessed on a customer-specific basis, with FERC requiring utilities to offer like rates, calculated on a cost-of-service basis, to all similarly situated customers. More recently, with the shift to market-based rates, FERC has undertaken a broader inquiry, focusing on whether market conditions are discriminatory. As Eisen has observed, “[i]nstead of judging whether an individual firm’s action is . . . discriminatory, [FERC] decides whether features of the wholesale markets’ operation contribute to [this] effect.”²⁴⁶

Some commentators have suggested that a carbon pricing scheme could be viewed as discriminatory.²⁴⁷ Peskoe, for example, has noted that opponents of carbon pricing may argue that it favors some generators over others.²⁴⁸ We recognize, as Peskoe does, that carbon pricing will necessarily treat generators differently based on their emissions profiles.²⁴⁹ This is because, while the same carbon price would be applied to all generating units, regardless of technology, the resulting carbon fee would differ based on each unit’s emissions.²⁵⁰ Some may, therefore, view carbon pricing as supporting renewable generating units at the expense of fossil fuel power plants. That is not necessarily the case, however. Some renewable generators (e.g., using biofuels) produce emissions which would be subject to carbon pricing. Those generators would face a higher carbon fee than fossil fuel plants with low or zero-emissions (e.g., clean coal facilities).

²⁴⁵ 16 U.S.C. § 824d(b).

²⁴⁶ Eisen, *supra* note 207, at 1812.

²⁴⁷ See e.g., Peskoe, *supra* note 207, at 26.

²⁴⁸ *Id.* (stating “opponents of carbon adder may argue that an adder would be contrary to FERC’s longstanding policy of not favoring particular types of electric generation”).

²⁴⁹ *Id.* (noting that “A carbon adder . . . is essentially a payment from owners of emitting resources to owners of emission-free resources. By definition, such a fee discriminates. Whether that discrimination is ‘undue’ is a separate matter”).

²⁵⁰ See *supra* part 6.

Despite the fact that it applies different fees to each generator, in our view, carbon pricing does not violate the prohibition on undue discrimination in the FPA. Differential treatment is permitted under the FPA if FERC “offer[s] a valid reason for the disparity . . . [which is related] to the achievement of permissible policy goals.”²⁵¹ With respect to a carbon price, NYISO may argue that disparate treatment of low- and high-carbon generators is necessary to improve the functioning of wholesale electricity markets, a long-accepted policy goal. A similar argument, albeit in a different context, was upheld by the Court of Appeals for the District of Columbia Circuit in *Wisconsin Public Power, Inc. v. FERC* (“WPP”).²⁵² That case involved a FERC decision exempting certain transmission providers from compliance with MISO’s OATT on the basis that they provided services under contracts pre-dating MISO’s formation. The court noted that FERC’s decision “was in some loose sense discriminatory” as the exempt providers were not subject to certain fees levied on others and could schedule services on short notice with greater flexibility.²⁵³ The court concluded, however, that the discrimination was not undue as it was necessary to solve a specific problem in the market stating:

MISO’s development was complicated by the existence of several hundred pre-existing bilateral contracts between its transmission owners and other utilities. These long-term contracts, known as grandfathered agreements (GFAs), obligated the transmission owners to provide transmission service under terms and rates that were inconsistent with the OATT . . . The tension between GFA terms and practices on the one hand and the MISO Tariff on the other hand was from the very beginning a fundamental problem in the proposed design and operation of MISO . . . [The] discrimination [complained of] was inherent in the solution to [that] problem.²⁵⁴

A carbon price would also address a fundamental problem in the design and operation of wholesale electricity markets. As explained above, the problem arises from the failure of markets to accurately value low- and high-carbon sources of electricity, which impairs competition. This problem is particularly acute in NYISO markets, which have been further distorted by state laws that impose diverse carbon prices on some but not all market participants. Extending carbon

²⁵¹ *Black Oak Energy, LLC v. FERC*, 725 F.3d 230, 239 (D.C. Cir. 2013)

²⁵² *Wis. Pub. Power, Inc. v. FERC*, 493 F.3d 239 (D.C. Cir. 2007).

²⁵³ *Id.* at 274.

²⁵⁴ *Id.* at 249, 270, 274.

pricing to all participants would remedy this distortion. To the extent that this results in differential treatment of participants, it is “inherent in the solution” to the problem at hand, and thus not undue under the test articulated in *WPP*.

This conclusion is further supported by the fact that those benefiting from the extension of carbon pricing account for a relatively small share of generation. The key beneficiaries of carbon pricing are, of course, zero-carbon generating units. Most of those units already have their zero-carbon attributes valued through New York’s CES. The remaining zero-carbon generators serve a relatively small share of electricity load. This is significant as, in *WPP*, the court emphasized that the limited extent of discrimination suggested it was not undue.²⁵⁵ In that case, those benefiting from the discriminatory practices accounted for approximately ten percent of peak load.²⁵⁶

8. CONCLUSION

In response to federal and state policies aimed at limiting the electricity sector’s carbon dioxide emissions, several ISO/RTOs have commenced reviews into whether and how to price carbon in wholesale energy markets. With some notable exceptions, emissions are not currently priced in wholesale markets, but rather treated as externalities. This results in a mismatch between the price and cost of fossil fuel generation which leads to higher levels of such generation than are socially optimal. To correct this market failure and equalize prices with costs, an ISO/RTO could include a carbon fee reflecting each generator’s emissions profile in its bids into the wholesale market. By causing high emitting generators, such as coal- and oil-fired units, to be dispatched less frequently, this would provide an incentive for investment in cleaner generating options and in non-transmission alternatives like energy efficiency or demand response.

Although the carbon pricing scheme we propose is conceptually simple, its implementation would raise numerous and complex issues. In the New York context, for example, any carbon pricing scheme proposed by NYISO would have to be integrated with RGGI. Thus, after determining a carbon fee for each generator—a difficult task in itself—NYISO would need to

²⁵⁵ *Id.* at 274 (noting that “the extent of discrimination was relatively small and not ‘undue’”).

²⁵⁶ *Id.* at 270.

adjust that fee to exclude the cost of RGGI allowances. NYISO would also need to resolve whether the fee should accommodate or displace Tier 3 of the CES.

NYISO's proposed carbon pricing scheme would be subject to review by FERC. This paper argued that a carbon price could be justified as a means of improving the functioning of wholesale markets to ensure just and reasonable rates. While we view this as fully consistent with the law and with long-standing FERC practice, we note that it would push the boundaries of what has been done in the past. A more modest approach would see carbon pricing used solely to reflect and harmonize state-level policies aimed at reducing electricity sector emissions.