Welfare Gains and Distributional Dynamics: A "Carbon Charge" in New York State

Daniel F. Noriega

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Abstract

Policies incentivizing the implementation of sustainable technologies have become widespread in the U.S. and the world. Economic theory suggests that a Pigouvian tax on Carbon Emissions may address the environmental externality by enabling competitive markets to internalize its costs. Consequently, carbon taxes are a widely supported policy alternative. However, it is not clear whether a carbon tax implemented exclusively into Wholesale Electricity markets will result in a net social welfare gain. Moreover, new policies for Wholesale Electricity markets will interact with pre-existing conditions including market distortions, such as subsidies, which should be taken into account when conducting a welfare evaluation. The present study leverages New York State's market data and estimates a partial equilibrium model using a Simulated Method of Moments to assess the welfare impacts of a potential carbon charge in New York. This exercise focuses on the overall welfare effects as well as the distributional impacts across agent groups.

1. Introduction:

Large-scale policies looking to incentivize the implementation of renewable and sustainable electricity generation technologies have become ordinary in the United States and elsewhere. However, power generation dynamics are sensitive to the geographic conditions and economic characteristics of a region. Carbon externalities generated by CO_2 emissions, as well as potential abatement mechanisms, vary substantially in cost and effectiveness depending on generation mix settings and load dynamics. Although Arthur Pigou provided economists with a sound theoretical foundation to address externalities by taxing them at the marginal damage value, it is not clear whether a carbon-tax implemented solely in the electricity sector would result in a welfare gain. The present study will assess whether a carbon "charge" implemented in New York State would result in a net social welfare gain.

Although carbon-taxes are a promising mechanism to reduce CO_2 emissions, their effects on electricity prices can be significant and outweigh the potential externality gains. In particular, carbon-taxes tend to increase electricity prices, which translates into transfers from consumers to incumbent producers. The contribution of this paper is to provide evidence that when considering a concrete location and policy environment, a carbon tax exclusive to Wholesale Electricity markets may result in a net welfare gain, although specific agent groups may be significantly harmed.

This study considers a partial equilibrium model tailored to the New York State Wholesale Electricity landscape, estimated using a Simulated Method of Moments. The timespan considered for analysis is 2017-2018, which at hourly intervals translates into 17,520 market intervals. After estimating the model, a carbon "charge" is incorporated, and new clearing conditions are calculated. Then, the total welfare gains and losses of different agent groups are calculated. Specifically, this study considers consumer and producer surplus changes, taxes collected, main subsidy savings and externality gains.

Several takeaways are apparent in the results. First, a carbon tax exclusive to Wholesale Electricity markets can be represent a social welfare gain, which is likely to be the case in New York State. However, welfare effects are not evenly distributed among agents, and a carbon tax is likely to significantly harm Electricity consumers while producers will capture most of the benefits. Additionally, policy interactions are important, and pre-existing market conditions can tilt the result in different directions. In the New York case, if Wholesale electricity prices increased, less subsidies would be required to maintain Nuclear-powered units, which ultimately represent a gain to consumers.

Similar studies have explored the distributional impacts of solar PV subsidies (Borenstein, 2017) and how increasing penetration of renewable generation can affect merchant power investment in conventional thermal generation (Bushnell, 2010). The present study uses a model similar to that utilized in (Bushnell, 2010). (Reguant, 2019) examines the interaction of retail-level tariff design with wholesale level renewable-related policies in the California market context.

2. Model:

To analyze the welfare impacts of a carbon tax in the New York Wholesale Electricity market (NYISO) the present exercise will use a partial-equilibrium model. The model incorporates features specific to the New York State market which may have to be adjusted if this study were to be replicated leveraging data from a different market.

2.1. Demand:

In general, an hourly demand function is specified by:

$$q_{th} = \alpha_{th} + \gamma_{th} p_{th}, \qquad \forall\, t, h$$

Where t represents a day and h a specific hour. Electricity demand levels are affected by exogenous factors; such as weather, day of the week, holidays, etc.; which is captured by the intercept α_{th}. The term $\gamma_{th} p_{th}$ captures the price responsive portion of demand, where p_{th} is the price level at a specific time and γ_{th} captures the price responsiveness. However, the present exercise assumes that demand will be the same as it was observed during the interval evaluated (2017-2018). This builds on two specific features of electricity markets: (i) electricity consumers are typically unaware of what wholesale electricity prices are at a specific point in time and are therefore unable to react in real-time, and (ii) market structures separate wholesale price variations from retail-level variations. Some studies, such as (Fabra, N. Reguant, M., 2014) have found that electricity consumers are somewhat responsive to changes on average electricity prices. However, overall, it is accepted that elasticities of demand for electricity consumption are very low, and consumers are largely unresponsive to changes in real-time wholesale prices.

Consequently, the present study assumes that demand for electricity is inelastic, although the possibility of incorporating a responsive demand side is left open for future studies building on the present exercise. Nonetheless, it should be noted that if an elasticity of demand is included, it would tend to reduce electricity consumption as prices increase, which would further reduce carbon emissions.

2.2. Generation:

The market is assumed to be competitive, which means that firms will produce as long as the wholesale price of electricity is greater than their marginal costs. The model will consider three main types of generators with different sets of constraints: thermal units, renewable generators, and must-run thermal generators.

$$Thermal\ Units\ Generation, g_{ith} = \begin{cases} 0, & if\ p_{th} < mc_i(g_{ith}) \\ [0, K_i] & if\ p_{th} = mc_i(g_{ith}) \\ K_i & if\ p_{th} > mc_i(g_{ith}) \end{cases}, \qquad \forall\, i, t, h$$

$$Where \quad mc_i(g_{ith}) = h_i * C_{sth}$$

The index i represents a specific generator, and indexes t and h again represent day and hour. K_i represents a generator-specific capacity and the expression $mc_i(g_{ith})$ represents a specific generator marginal cost, which depends on the generators' efficiency or "Heat Rate", h_i, and an unobservable variable, C_{sth}. C_{sth} captures the specific generator's type (indexed s) operational costs; system conditions, such as congestion and transmission constraints; and additional services required to operate the grid, such as *Ancillary Services* (e.g. Voltage Support, Regulation, etc.). C_{sth} will be modelled as an AR(1) process that follows:

$$C_{sth} = \rho C_{sth-1} + (1-\rho)\mu + \varepsilon\,, \qquad \varepsilon \sim N(0,\sigma)$$

Where ρ, μ and σ will be estimated using New York Wholesale electricity market data.

$$Renewable\ Units, r_{jth} = \lambda_{th} * K_j\,, \qquad \forall\, j,t,h$$

Renewable units' generation, r_{jth} ,will be constrained by the weather conditions that may vary for each time interval, λ_{th}. λ_{th} captures for example how strong the wind will be blowing during a specific time interval. For the purpose of the present study, since in the New York case Wind penetration is not very high yet, λ_{th} will just be calibrated as a constant that delivers a similar Wind capacity factor to that observed in the data.

Must-run units, such as Nuclear generators, and hydro units, will be modeled with the same generation as observed in the data.

$$"Must-run"\ thermal\ generators/hydro, n_{th} = n'_{th}, \qquad \forall\, t,h$$

2.3. Carbon-charge:

The Carbon-charge will be specific to each thermal generator (Hydro, Wind and Nuclear units have virtually zero emissions, and therefore, are not subject to the CO_2 charge). It will modify the generator marginal costs, so that they become:

$$mc_i(g_{ith}) = h_i C_{sth} + e_i\tau\,, \qquad \forall\, j,t,h$$

Where now the expression $e_i\tau$ captures the generator specific marginal carbon charge calculated as the product of the generator specific emissions' rate, e_i, and the unitary carbon charge, τ.

2.4. Equilibrium:

In equilibrium, supply of electricity (i.e. generation) and demand (i.e. load) must clear. Specifically, the clearing condition is described by:

$$q_{th} = \sum_i g_{ith} + \sum_j r_{jth} + n_{th}\,, \qquad \forall\, t, h$$

Where the sum over thermal units i, uses generators sorted by marginal costs. The wholesale price, p_{th}, will be set equal to the most expensive unit's marginal cost (i.e. marginal unit's cost). The solution can be expressed as the following first-order condition:

$$p_{th} - mc_i(g_{ith}) - \varphi_{ith} \leq 0, \qquad g_{ith} \geq 0\,, \quad \forall\, i, t, h$$

Where φ_{ith} represents the potential infra-marginal revenue for a generating unit and a thermal unit is on the margin (which is the case in the present New York State model).

3. Data:

The objective of this exercise is to estimate the welfare impacts that a carbon charge would generate if it were to be implemented in the wholesale electricity markets in New York State. For that purpose, the present study leverages data from the New York Wholesale Electricity market (NYISO) from the years 2017 and 2018, as well as emissions and plant level efficiency data from the U.S. Environmental Protection Agency ("EPA").

3.1. Generation Data:

The NYISO system counts with 702 generating units (some located in the same facility) comprised of a variety of technologies, such as Combined Cycle plants, combustion turbines, Conventional Hydro plants, Wind turbines, Internal Combustion turbines and Cogeneration plants. Additionally, plants in the NYISO territory can utilize several fuel types including Fuel Oil, Kerosene, Butane, Bituminous Coal, Solid Waste and Uranium, among others.

However, four fuel types are especially relevant in the New York State Wholesale Electricity market context: Water (Hydro plants), Natural Gas, Wind and Uranium (Nuclear plants). In 2017, these 4 fuel types provided over 97% of the energy produced in New York. Moreover, their combined Generation Capacity accounts for over 90% of the New York Control Area ("NYCA") Installed Capacity.

Figure 1: 2017 Shares of New York Control Area's Installed Capacity and Production

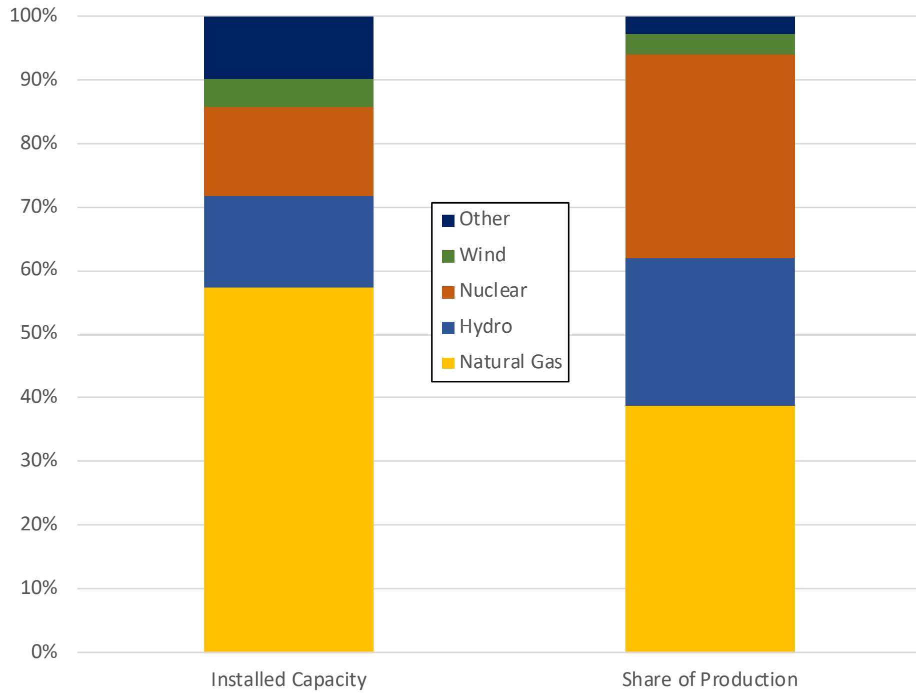


Figure 1 shows the shares of Installed Capacity and Production in year 2017 by fuel type. Although about 57% of the Installed Capacity in the NYCA region is represented by plants capable of utilizing Natural Gas as their primary fuel, those plants only produced about 39% of the NYCA generation in 2017. Conversely, Hydro and Nuclear plants, despite representing about 14% of the generation capacity each, generated about 23% and 32% respectively, which reflects considerably higher capacity factors on average compared to Natural Gas plants. Wind, on the other hand, represents 4.5% of the Installed Capacity, and generated 3.2% of the NYCA production in 2017. Wind production reflects the physical constraints of the technology, which relies on highly uncertain climate dynamics that ultimately impact its capacity factor, which in 2017 was about 27.7%. The main Fuel Types' Capacity Factors in 2017 within the NYCA region are shown below.

Table 1: Main Fuel Types' 2017 Capacity factors within the NYCA Region

Natural Gas	25.9%
Wind	27.7%
Hydro	61.2%
Nuclear	89.1%

Generators' emission data was collected from the Emissions and Generation Resource Integrated Database ("eGRID") maintained by the U.S. Environmental Protection Agency. The current release contains information from year 2016. The emissions data was restricted to operating generators. Table 2 below shows the main descriptive statistics for Natural Gas generators' efficiencies and emissions. Generators located in a single facility are grouped into a single observation. Additionally, because thermal generators are affected by the temperature of the air when operating, the generating capacity was adjusted to their summer capability.

Table 2: Descriptive Statistics for Emissions and Heat Rates/Efficiency Data

	Efficiency	***CO2 Emissions***
	[BTU/kWh]	*[lb/MWh]*
Mean	10,173	1,256
Std. Deviation	6,828	925
Maximum	56,165	6,905
Minimum	2,801	327
Combined Generating Capacity *[MW]*		24,348
Number of Values		82

When calculating the tax adder that each generator will face, their specific CO_2 emission rates were considered, as well as the value for the Social Cost of CO2 Emissions recommended by the Interagency Working Group on Social Cost of Greenhouse Gases of the United States Government for the 2015-2020 period assessed with a 3% discount rate, $36 USD. The Interagency Working Group specifies several values for different evaluation cases, which could be considered in future studies which may build on the current exercise.

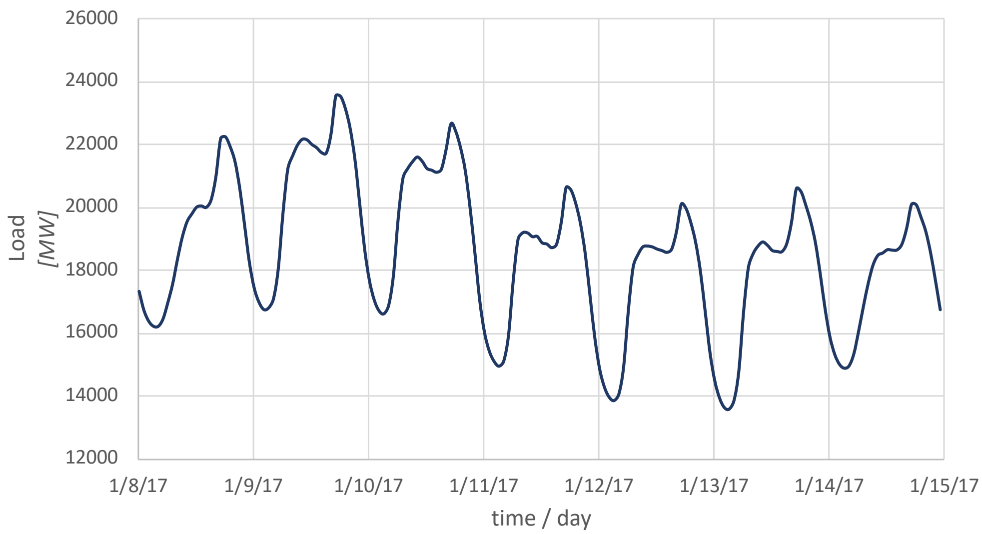
3.2. Load Data:

The present exercise considers hourly load values in the NYCA region from years 2017 and 2018. The NYISO reports load values on a zonal basis,[1] which represents a total of about 193 thousand observations. Aggregated into total hourly values, loads input translate into 17,520 observations. The largest loads are typically located in the New York City-Long Island area, around downstate New York.

Figure 2 below shows a typical winter weakly load profile. Loads are typically larger around noon, and lighter at night. Over the years considered, hourly load values varied from 11,831 to 31,861 MW, with a mean value of 18,121 and a standard deviation of 3,302.

[1] The New York Control Area is divided into 11 Load Zones for pricing purposes, which are named with letters from A to K.

Figure 2: Typical Weekly Load Profile. Jan 8th to Jan 14th, 2017



3.3. Pricing Data:

The present exercise leverages integrated-hourly prices from years 2017 and 2018 for the NYISO market. 17,520 hourly intervals were utilized, each containing 11 price points for each of the NYCA load zones. To aggregate zonal prices, load-weighted averages for the 11 NYCA zones were considered.
Table 3 below summarizes the main descriptive statistics for pricing and load data.

Table 3: Main Descriptive statistics for Price and Load Data

	p_{th}	q_{th}
Mean	33.64	18,121
Minimum	0.00	11,831
Maximum	1,188.68	31,861
Std. Deviation	33.43	3,302
N. of Observations	17,520	

3.4. Assumptions

Because Natural Gas, Nuclear, Hydro and Wind plants combined supply over 95% of the electricity generated within the NYCA region in a typical year, the present study limits the fuel types evaluated to these 4 types. This is especially sensible since the current model will not consider detailed transmission congestion circumstances under which an economic generator may have to be replaced for a less economic one.

In addition, since Hydro and Wind-based plants have operating costs that are close to zero and Nuclear plants are in practice must-run units due to difficulties in cycling dynamics (turning them off and starting them again), their output will be assumed constant at a level that results in a similar capacity factor to that observed in 2017. The combined-adjusted generating capacity of Nuclear, Wind and Hydro units will therefore be assumed as constant at 8,135.5 MW. Consequently, Natural Gas-fired units will be at the margin in the model, which is largely consistent with the reality of the NYISO market.

New York already has policies looking to incent the adoption of sustainable generation technologies in place. One of particular relevance is the Clean Energy Standard which stipulates, among others, the obligation to purchase *Zero-Emission Credits* ("ZECs") for Load-Serving entities within the NYCA region to sustain the production of nuclear-based power plants. If the price of electricity increased, the need for the subsidy would decrease, as nuclear plant's revenue would increase. In 2017, the cost of ZECs was set at ~$17.54 USD/MWh. To estimate the savings from lower ZECs' prices the present study will calculate the product of Nuclear energy production and Nuclear plants' excess revenues per MWh up to the current ZECs' price.

4. Estimation Strategy

To estimate the parameters describing the evolution of the unobservable C_{sth}, ρ, μ and σ, the Simulated Method of Moments ("SMM") is employed. Specifically, this exercised conducted 1,200 simulations of the 17,520 hourly intervals studied. 4 data moments were considered. They were:

$$m_1 = \frac{\sum_t^T p_{th}}{t_{max}}$$

$$m_2 = var(p_{th} * q_{th})$$

$$m_3 = corr(p_{th}, q_{th})$$

$$m_4 = corr(p_{th}, p_{th+1})$$

The moments were selected looking to capture the system dynamics in terms of price and load variations. The simulated moments were estimated as follows:

$$\hat{m}\,(\tilde{x}|\theta) = \frac{1}{S}\sum_{s=1}^{S} m\,(\tilde{x}_s\,|\theta)$$

The moment errors were normalized with respect to the data moments as follows:

$$e(\tilde{x}, x|\theta) \equiv \frac{\hat{m}(\tilde{x}|\theta) - m(x)}{m(x)}$$

Finally, the SMM estimator minimized the following criterion function:

$$\hat{\theta}_{SMM} = \theta : \quad \min_{\theta} \; e(\tilde{x}, x|\theta)^T \, W \, e(\tilde{x}, x|\theta)$$

Where the weighting matrix utilized, W, was a 4 by 4 identity matrix. The errors obtained with this weighting matrix were acceptable. However, moment errors could be further minimized if more optimal weighting matrices, such as a 2-step weighting matrix, were used. Nonetheless, the process was computationally intensive[2], and further refinements of the weighting matrix are left for future work building upon the current exercise. The resulting parameters and errors are shown below.

Table 4: Estimated Parameters and Corresponding Standard Errors. 17,520 hourly intervals considered.

	Value	***Standard Error***
ρ	0.66	0.0002
μ	4.38	0.0052
σ	2.67	0.0033

Table 5: Moment Differences. 17,520 hourly intervals considered.

m_1	0.22
m_2	-0.16
m_3	-0.57
m_4	-0.001

The minimized criteria function value was ***0.405***. Additionally, as a robustness check, different starting values for the parameters were selected but similar results were obtained. The optimization converged in 22 iterations.

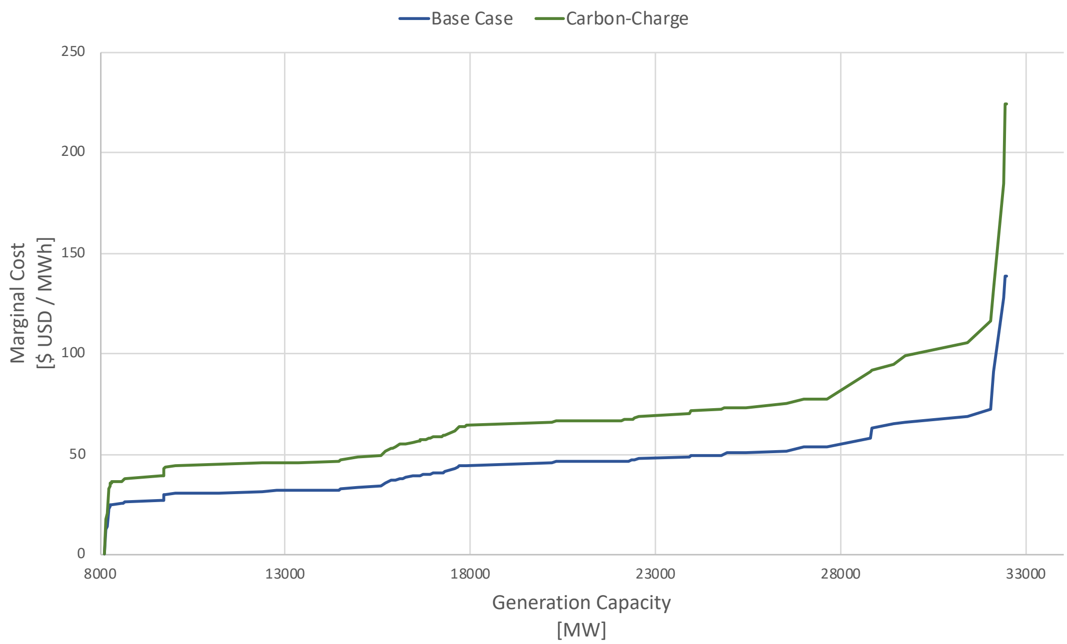
As outside moment corroborations, annual emissions obtained in the simulation were compared to EPA reported values for New York in 2016 (latest report). The average simulated annual emissions' quantity was 36.3 million tons of CO_2, which is 16.7% higher than the EPA-reported value for 2016, 31.1 million tons. Considering that additional emissions could be displaced by imports from non-emitting resources not accounted for in the model, such as Hydro-power generation from Quebec, the simulated results are promising. Additionally, the load-weighted average electricity for the 2017-2018 period in the NYCA was ~$36 USD/MWh, which is similar to the simulated load-weighted average of ~$42 USD/MWh.

[2] The minimization process with 1,200 simulations and a 4 by 4 identity weighting matrix converged after over 6 hours of computing time.

5. Results and Discussion

Using the estimated model, it is possible to simulate the welfare impacts of a hypothetical carbon charge for the externality cost of CO_2 emissions. Different producers will be affected in different magnitudes by such charge, which combined with the high variability of load and its interaction with wholesale prices, makes of simulation a must to estimate the impacts. Figure 3 below shows how the adjusted NYCA supply curve with a C_s value of 4.38 (arithmetic average of simulated values) would be affected by a carbon charge of \$36 USD per ton of CO_2. The adjusted supply curve considers that Hydro, Wind and Nuclear resources at operate at a zero marginal cost and operating Natural Gas-fired plants face $C_s$costs.

Figure 3: Effect of a \$36 USD per ton on the NYCA supply curve



With a carbon-charge adjusted supply curve, and satisfying market clearing conditions for each hourly interval, it is possible to estimate the welfare impacts of the charge. In particular; infra-marginal revenues for producers are accounted for as producer surplus; consumer expenditure increases are a decrease in consumer surplus; and taxes collected, ZECs' cost reductions and emissions reduction are all accounted for as welfare gains. Table 6 below summarizes the welfare impacts generated by a \$36 USD per ton of CO_2 charge.

Table 6: Welfare effects of a carbon-charge

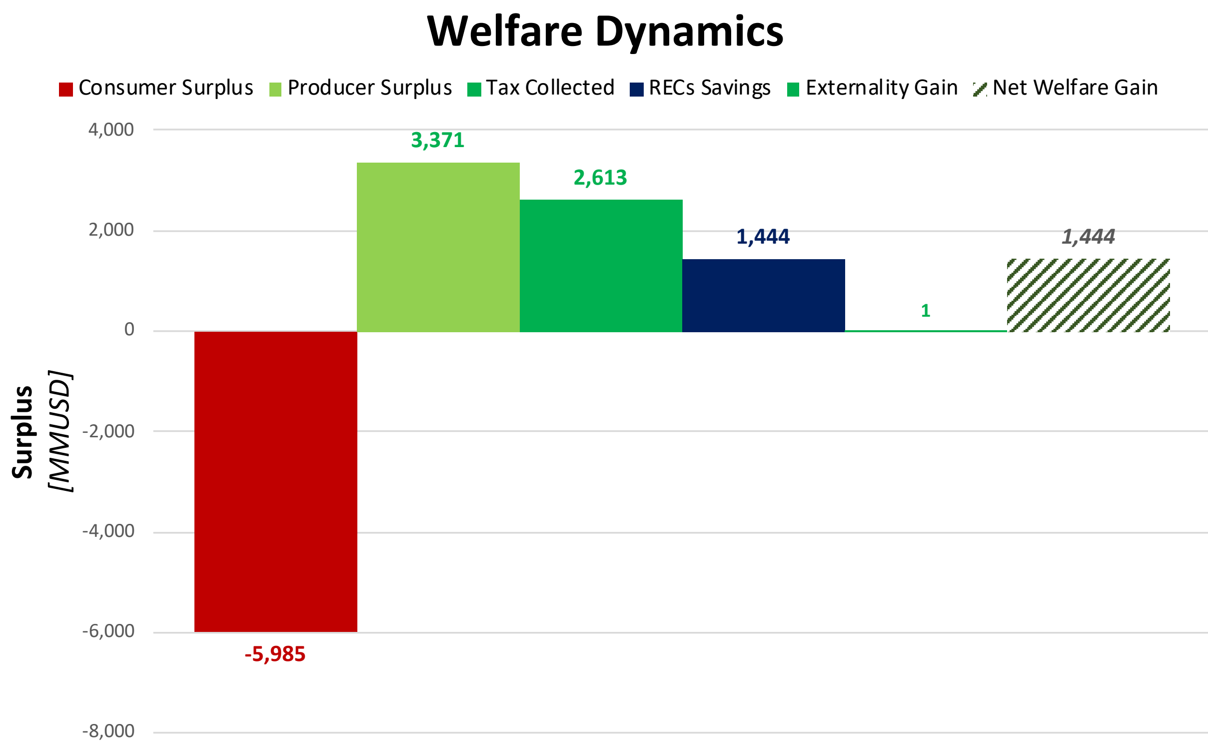
	Base Case	Carbon Charge		Normalized Change
Electricity Cost	42.14	60.99	[$/MWh]	[Δ $USD / MWh]
Producer Surplus	7,493	10,863	[MMUSD]	11
Wind	317	458		18
Nuclear	3,387	4,898		18
Hydro	2,160	3,123		18
Gas	1,629	2,384		4
Consumer Expenditures	13,379	19,364	[MMUSD]	
Tax Collected		2,613	[MMUSD]	
RECs Savings		1,444		
Emissions	72,604	72,578	[000 ton CO2]	
Externality Cost	2,614	2,613	[000 USD]	

Although the overall welfare calculation results in a net social gain for New York State (+$1,444 MMUSD), benefits are not evenly distributed among agents. Consumers are facing substantially higher prices ($42 vs $61 USD/MWh) and their surplus is decreasing significantly as a result. This social loss is offset mainly by gains in producer surplus ($3,371 MMUSD), tax collection ($2,613 MMUSD) and a decrease in the necessary subsidies to maintain Nuclear power generation ($1,444 MMUSD). Environmental gains are marginal (~$1 MMUSD), although this effect can be increased in a more dynamic model incorporating potential new plants that will decide to enter the market once prices increase, as well as a possible demand response that could decrease loads and further reduce emissions. The main expected benefit from a carbon charge, however, which would be to dispatch existing resources in a more efficient way, is not apparent in the results. This is a consequence of the fact that New York's fleet has a relatively high participation of renewable resources and has undergone a recent decarbonization process, replacing coal-fired plants for "cleaner", more efficient Natural Gas plants. Because the correlation between less polluting, more efficient Natural Gas plants, and lower marginal production costs is high, the marginal benefit of a dispatching selection incorporating emission benefits is minor.

Even within producers, however, the impact is differentiated. Cleaner units (Hydro, Nuclear and Wind) are capturing most of the benefits (increase of $18 USD/MWh in infra-marginal revenues) relative to Natural Gas-fired units (increase of $4 USD/MWh in infra-marginal revenues).

Figure 4 below shows the relative impact of a carbon charge on each agent group. The underlying mechanism resulting in a net relatively small welfare gain is a large surplus transfer from consumers to producers. The welfare gain represents ~7.5% of the total Consumer Expenditure in the carbon-charge case, but their expenditures are about ~45% higher than those in the Base Case.

Figure 4: Welfare dynamics created by a carbon charge by agent group



It should be noted that for a new price level of ~$60 USD/MWh, additional renewable technologies, which were too expensive to enter the market under the Base Case may find that the new market conditions are beneficial to them and decide to enter the market. Increased levels of penetration of technologies with marginal costs close to zero will depress the wholesale price of electricity again, however, so that only a limited quantity of renewable generation can economically enter the market. Additionally, as the best locations are utilized for Wind- and Solar-based facilities, which currently are the main renewable technologies capturing merchant power investment, the Levelized Cost of Electricity for those technologies will increase. Therefore, although higher electricity prices may incent additional investment in renewable technologies, such investment will be limited by the Real-Time Wholesale Market clearing conditions, which will tend to decrease prices, and increasing marginal supply costs.

6. Conclusions

This paper studies the welfare impacts of a potential carbon "charge" in New York State, focusing on the overall welfare impact of the policy but also considering specific distributional dynamics among different agent groups. For this purpose, this study uses a partial equilibrium model calibrated using a Simulated Method of Moments and New York Wholesale Electricity market's 2017-2018 data.

The evaluation shows that a carbon "charge" could be beneficial to society overall, although important transfers among different agents would occur. Specifically, consumers would see a substantial increase in their expenditures while producers would see an increase in their infra-marginal revenues. Even within producers, however, differentiated impacts were also observed, as technologies with lower emissions which in the New York case are mainly Hydro, Nuclear and Wind powered facilities, capture more benefits. Additionally, interactions with existing policies are also relevant. In the New York case, a carbon charge might reduce or eliminate the need for subsidies to maintain Nuclear-based generators.

Additional features may enhance the results of the model utilized, such as considering import-export dynamics and incorporating a price responsive capability on the demand side. Also, evaluating the competitive entry of new resources into the market in response to higher prices might represent both price variations and emission level changes which would directly affect the outcome of the welfare impacts' assessment.

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