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Early nuclear power plant retirement and policy choices in the New York electricity market

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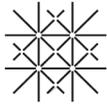
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Early nuclear power plant retirement and policy choices in the New York electricity market

February 2025

Muhammad Maladoh Bah^{1*}, Hannes Weigt²

Abstract

The U.S. nuclear industry has overcome a challenging period during which low wholesale market prices threatened the survival of nuclear power plants (NPPs). From 2017 to 2019, several U.S. states initiated out-of-market support schemes to bolster the financial conditions of NPPs. This paper provides a comparative cost assessment between the preservation of three upstate New York NPPs under the zero-emission credit (ZEC) support scheme or an early retirement. In addition, the paper explores future market development scenarios with a carbon price mechanism. A bespoke cost-minimization dispatch model is developed for the New York electricity market along with four neighboring electricity markets. The comparative cost assessment of a nuclear phaseout and ZEC expenditures is not definitive. Results indicate that phasing out upstate NPPs in 2018 and 2021 incurred a slightly higher cost burden for New York consumers compared to the total ZEC expenditures. In contrast, phasing out upstate NPPs in 2030 incurs a lower cost burden compared to the total ZEC expenditure, mainly due to a high credit price. Furthermore, results show that a low carbon price of \$51/ton would raise average NYISO prices by \$24.1/MWh, thereby improving the long-term income conditions of NPPs, and ensuring sufficient accumulation of nuclear decommissioning funds. The study provides policymakers with a sequence of optimal policy options taking into account the pace of renewable development.

Keywords: nuclear power plant, ZEC, New York, electricity market, carbon price

JEL Classification: L94, Q41, Q48

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1. Introduction

Like in many other countries, the U.S. nuclear industry has gone through a challenging period in the recent decade. Low market prices due to low fossil fuel prices, low or modest carbon policies, or increased renewable generation threatened the revenue prospects of nuclear power plants (NPPs) operating in wholesale electricity markets. Given the importance of NPPs for many systems in terms of generation share, baseload provision, and their role as carbon free electricity provision, discussions on support interventions rose up. To stabilize the financial standing of NPPs and meet imposed climate targets, five U.S. states implemented direct out-of-market support schemes between 2017 to 2019. The subsidy schemes cover 19 operating reactors and account for 20% of the total U.S. nuclear capacity.³ Despite the upturn in market conditions after the Covid pandemic, the federal government intervened in late 2021 with two additional support packages for NPPs—the civil nuclear credit (CNC) and the nuclear power production credit (NPPC) scheme.

Those interventions highlight the important role of the nuclear industry for U.S. electricity systems, but whether the economic and environmental reasoning for the nuclear support schemes was justified has been questioned (see Lovins 2017; Tsai and Gülen 2017; Cebulla and Jacobson 2018, and Bah 2023). In addition, the implemented schemes represent rather short to mid-term interventions (i.e., ranging from six to twelve years) in terms of nuclear or electricity market policies and should be contrasted to the longer-term trends, namely increases in renewable generation and a stronger move towards carbon schemes. For example, the New York Independent System Operator (NYISO) is contemplating the integration of a carbon price mechanism into the wholesale market.⁴ This initiative is projected to increase wholesale market prices, potentially bolstering the financial prospects of NPPs as well as renewable technologies in the long run. A report commissioned by NYISO suggest that a \$40/ton carbon price could elevate wholesale market prices by approximately \$19/MWh in 2025 (Newell et al. 2017). Similarly, Montalvo, Loiacono, and Berman (2018) found that implementing a carbon price would increase average market prices by approximately \$25/MWh in 2030. The anticipated rise in future market prices through a carbon price mechanism could independently enhance the financial conditions of both nuclear and other carbon free technologies, rendering specific technology specific support schemes unnecessary.

Given this background, this study aims to answer three related policy-relevant inquiries: (1) It provides an assessment of the direct nuclear support schemes and its potential costs and benefits. (2) It investigates the long-term revenue prospects of NPPs under a more stringent carbon policy regime. (3) It relates those

³ Refer to Bah (2023) for an overview of state and federal nuclear support schemes.

⁴ It is noteworthy that NYISO operates within the regional greenhouse gas initiative (RGGI). Thus, the current market is not entirely free of carbon pricing.

findings back to the general nuclear financing challenges, especially in the context of securing enough funding for nuclear decommissioning. The three aspects will provide a mapping to identify an optimal policy choice for policymakers. To address these lines of inquiries, we focus on a comprehensive model based case analysis of New York and their zero-emission credit (ZEC) policy mechanism to support their NPPs as well as their envisioned carbon and renewable developments until 2030.

New York is used as an exemplary case that neatly covers all relevant dimensions and can likely provide insights that are also relevant for other markets and systems. The NPP fleet in the State of New York is ageing and gradually approaching the end of their operating lifespan (i.e., by 2035, three out of the four reactors will reach the end of their operating license) providing a representative example for many restructured electricity markets. The interplay of direct intervention policies, long term system transformation ambitions, and financing challenges is a common setting both in the U.S. and in Europe. Wholesale market dynamics and revenue threats not only impact direct operation but also the decommissioning prospects. In the U.S., most nuclear plant owners accrue decommissioning funds over a plant's lifetime which is stored in a decommissioning trust fund (DTF) designated solely for facility decommissioning at the end of its lifecycle.⁵ However, early retirement or low income periods create substantial funding deficits, as most funds accumulate during the later phase of a plant's life (Hewlett 1991). Album, Braend, and Johnson (2017) evaluated decommissioning financing solutions for several countries and cautioned that the early closure of NPPs in electricity markets will not generate fees for decommissioning funds, thereby inevitably leading to funding shortfalls. Thus, direct support interventions as well as long term policy mechanisms like a carbon price could significantly improve the financial position of NPPs, enabling their continued operation while generating the needed revenues to cover future decommissioning costs.

The remainder of the paper is structured as follows. Section 2 provides background on New York State, covering the overall electricity system conditions, nuclear power, and energy policies. Section 3 presents the electricity market model and data. Section 4 outlines the scenario design. Section 5 presents and discusses the findings. Finally, Section 6 concludes the study and provides policy implications.

⁵ Refer to Lordan-Perret, Sloan, and Rosner (2021) for a detailed overview of decommissioning funding regulations and scenarios for a decommissioning fund shortfall.

2. Case Study: New York State

Our study is focused on the electricity market in the State of New York. Following we will provide a short overview of its energy landscape. Section 2.1 presents an overview of the electricity market and the role of the New York Independent System Operator (NYISO), Section 2.2 discusses the role of nuclear in the state energy mix and Section 2.3 presents the relevant existing and future energy policies.

2.1. Overview of the New York power system

The New York electricity system is characterized by a mix of hydro, nuclear, and fossil generation (mostly natural gas based) with a small share of new renewable energies. The state electricity system can be described as two grids (up- and downstate) interconnected by high voltage transmission lines (Tierney and Hibbard 2019). The non-profit NYISO is tasked with operating the state electric grid, overseeing the various electricity markets, and establishing long-term electricity planning (FERC 2011). NYISO segregates the grid into 11 zones, designated as zones A to K as illustrated in Fig. 1. The upstate segment of the grid spans zones A to E, while downstate covers zones F to K.

The upstate system is dominated by low cost zero emission generation facilities (i.e., hydropower and nuclear) which account for ca. 90% of upstate electricity production. In contrast, the downstate system is largely dominated by high cost fossil fuel generation, accounting for ca. 70% of downstate electricity generation (NYISO 2020b). While both subsystems have roughly similar total generation levels (see Section 3.2 for more details on the generation structure in New York), the upstate system only represents about one third of the total demand leading to significant exports from upstate to downstate. However, transmission constraints within the lines result in significant zonal price differentials. Typically, market prices are much lower in upstate New York as compared to downstate New York (see also Fig. 5).

The New York system is interconnected with its neighboring systems, namely PJM, ISO New England (ISONE), Hydro-Québec (HQ) and Ontario's Independent Electricity System Operator (IESO), and significant import and export takes place on the respective cross-border connections (see also Section 3.3).

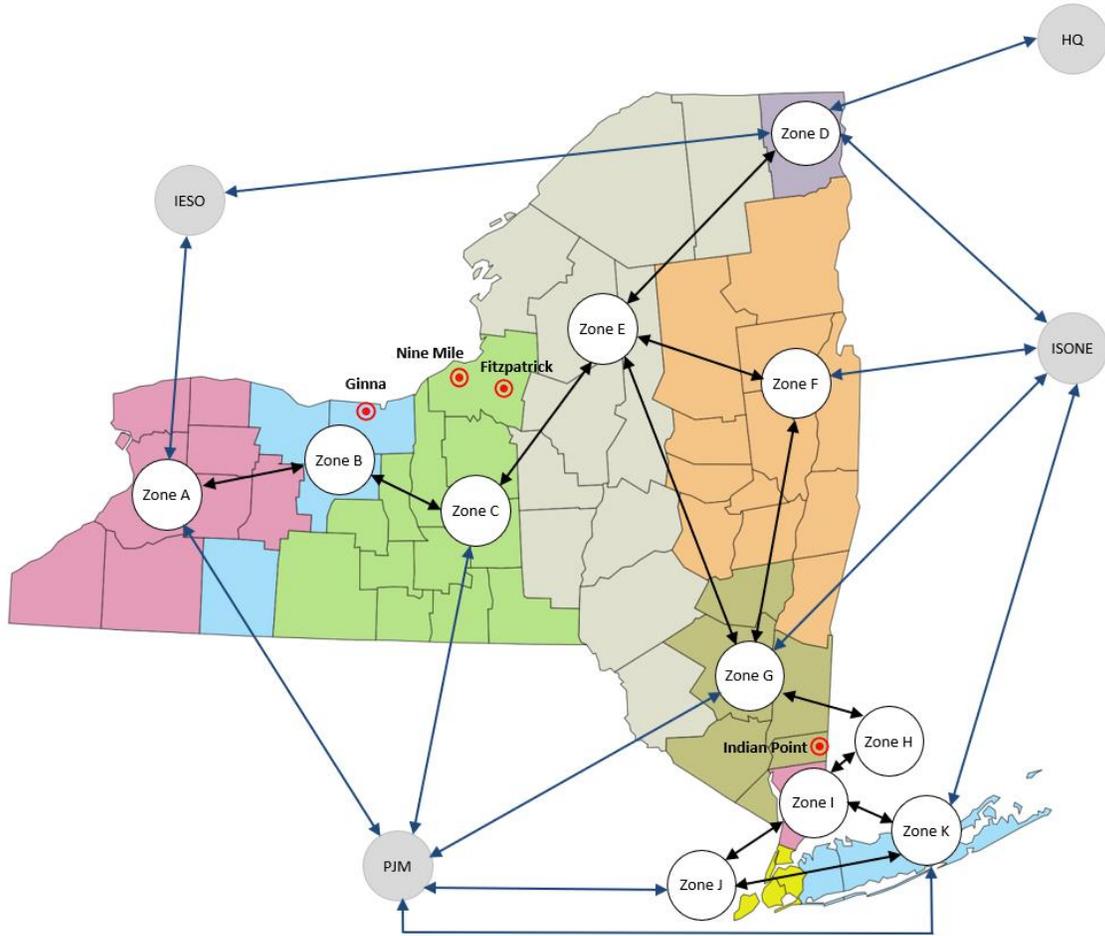


Fig. 1. Simplified model representation of the NYISO system and external markets.
 Note: Black lines represent internal NYISO network and blue lines represent cross-border connections.
 Source: Own illustration.

2.2. Nuclear power

In 2022, the State of New York had three remaining active NPPs accounting for 9% of installed energy capacity (NYISO 2022b); all within the upstate system. In the downstate system, the three-unit Indian Point Energy Center (Indian Point) is shut down. Constellation Energy Corporation owns all the three upstate NPPs. Furthermore, all three NPPs received 20-year NRC license extensions and are expected to remain in service up to 2029 (Ginna) and beyond. As of 2022, the average availability factor for all three NPPs stands at 97.3%, reflecting a high reliability level (IAEA 2023).

Indian Point with a combined capacity of 2.3 GW operated for 59 years from 1962 until the last unit closure in 2021. Indian Point was owned by Entergy Corporation until 2021 where it was sold to Holtec International for decommissioning. While Indian Point Unit 1 had already shut down in 1974, Indian Point's

owner Entergy announced the closure of the Indian Point-2 (IP2) reactor in April 2020, four years prior to its license termination date due to depressed wholesale energy prices. Shortly thereafter, in April 2021, the last remaining downstate nuclear reactor Indian Point-3 (IP3) retired prematurely, thereby shrinking New York’s nuclear generation capacity from 4.3 GW to approximately 3.2 GW. The closures of IP2 and IP3 reactors were announced in 2017 as part of Entergy’s overall strategy of withdrawing from the merchant generation business. NYISO conducted an assessment of IP2 and IP3 closures and concluded that the closures posed no imminent threat to the reliability of the grid (NYISO 2020a). Table 1 provides a summary of operating and retired nuclear reactors in New York and Fig. 1. illustrates the relative positions of the reactors.

Table 1: Summary of nuclear power plants in New York.

Reactor	Type (Capacity MW)	Ownership	Market Zone	Age ^a	License expiry	Status
Ginna	PWR (560)	Constellation	B	53	2029	Operating
Fitzpatrick	BWR (813)	Constellation	C	48	2034	Operating
Nine Mile Point-1	BWR (613)	Constellation	C	54	2029	Operating
Nine Mile Point-2	BWR (1,277)	Constellation	C	35	2046	Operating
Indian Point 1	PWR (257)	Entergy ^b	H	12	-	Retired
Indian Point 2	PWR (998)	Entergy	H	47	-	Retired
Indian Point 3	PWR (1030)	Entergy	H	45	-	Retired

^aAge calculated as of 2023 from date of commercial operation. For retired plants, age at shutdown year is reflected. ^bFormer owner Source: (IAEA 2022; NRC 2023).

2.3. New York state energy policies

As with many other restructured electricity systems in the U.S. and Europe, the New York electricity system is subject to multiple market and regulatory structures and policies that interact with each other. For the context of our assessment, we are focusing on the nuclear related policies, the long-term carbon targets and policies, as well as the general system transition perspective (i.e., renewable expansion).

The State of New York’s 2015 energy plan aims for a reduction in total emissions by 40% and ensuring that 50% of New York’s energy is generated from renewable resources by 2050 (NYSERDA and NYSDPS 2019). To achieve those goals, the State of New York introduced the clean energy standard (CES) in 2016. The CES established two financial mechanisms - the zero-emission credit (ZEC)⁶ program and the

⁶ A ZEC is defined as a “credit for the generation by an eligible zero carbon electric generating facility of one MWh of electricity with zero-emissions attributes that is consumed by retail customers in New York State” (NYSDPS 2016, 2).

renewable energy standard (RES). The ZEC program is mostly aimed at the nuclear industry and provides financial support to vulnerable upstate nuclear plants over a 12-year period from 2017 to 2029. The three upstate NPPs were eligible to receive ZECs. Indian Point was considered ineligible to receive subsidies by the Public Service Commission (PSC) since it was not deemed to be in any financial risk (Brasington, Cox, and Fontanella 2016).

From a design perspective, the ZEC scheme provides additional out-of-market monetary remunerations for NPPs. The New York State Energy Resources and Development Authority (NYSERDA) oversees the entire scheme with specific regulations governing ZEC payments, LSE charges, among others as Fig. 2 illustrates. The starting point of the ZEC calculation is the Social Cost of Carbon (SCC) published by the U.S. Interagency Working Group (USIWG). As NPPs receive an allowance due to participation in the Regional Greenhouse Gas Initiative (RGGI), the RGGI price allowance is then subtracted from the SCC. The remaining values (in tons) are subsequently multiplied by the New York carbon emission rate to derive the baseline ZEC value. The ZEC framework also incorporates a phase-out mechanism that activates if electricity market prices rise. Accordingly, if the combined forecasted energy and capacity price exceed \$39/MWh, the ZEC price will be lowered by the amount above the ceiling (PSC 2016).

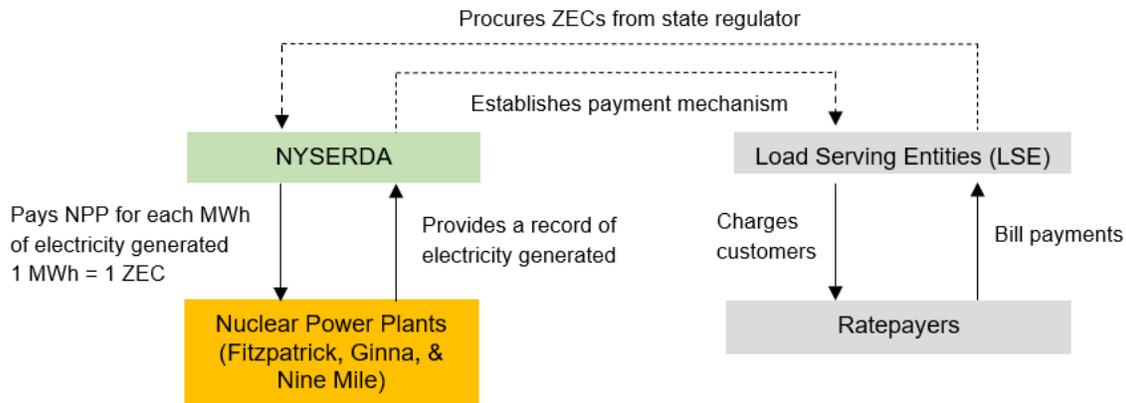


Fig. 2. Schematic representation of the New York ZEC scheme.
Source: Adapted from (Bah 2023a).

In contrast to ZEC's, the RES provides financial support to renewable technologies through the renewable energy credit (REC) mechanism. The REC mechanism is separated into three tiers: tier 1 (new renewable resources), tier 2 (maintenance resource and competitiveness program) and tier 4 (New York City renewable energy). Overall, both ZEC's and REC's constitute 20% of New York States generation portfolio and the share is expected to rise significantly to about 50 to 60% by 2030 (Tierney and Hibbard 2019).

From a broader perspective, the State of New York is also part of the RGGI. The RGGI is a regional cap and trade program that was launched in 2009 and comprises of eleven Northeast and Mid-Atlantic states including New York. The program allocates CO₂ allowances for each state based on their relative share of emissions generated from the power sector. Collectively, state allowances form the regional CO₂ cap on power sector emissions. Power plant owners with capacity equivalent to 25 MW or greater are mandated to procure CO₂ allowances for each compliance period from a centralized auction or through secondary markets (Hibbard et al. 2018). Historically, between 2008 and 2018, the average CO₂ allowance clearing price has remained below \$5/ton (RGGI 2023). As of 2023, the clearing price stands at \$13.49/ton.

In the long run, the carbon price is expected to play an important role in achieving the 2050 targets. To this end, in 2018, the Integrating Public Policy Task Force (IPPTF) introduced a proposal outlining a carbon pricing system for New York. The proposal envisages embedding the Social Cost of Carbon (SCC) into NYISO administered wholesale energy market (NYISO 2018b; Tierney and Hibbard 2019). More specifically, NYISO would charge each electricity generator for its carbon emissions. In turn, generators would add the carbon charge to its energy market offers, thereby raising the wholesale market clearing price (NYISO 2018c). In 2020, the New York State Department of Environmental Conservation (DEC) released a carbon valuation guidance document and estimated the value of carbon to range between \$51 to \$406/ton, with a central value at \$121/ton (DEC 2023). In terms of the interaction with the existing RGGI scheme, the IPPTF proposal suggested that the gross SCC would be adjusted for suppliers liable for RGGI. Specifically, *“the applicable carbon price would be based on the Public Service Commission’s (PSC) Gross SCC with adjustments for RGGI allowance prices for those suppliers required to hold RGGI allowances”* (NYISO 2018c, 5).

Within our case study we will focus on the ZEC mechanism and the interplay with the New York NPP units as well as the long-term prospects of carbon prices for the system and nuclear units. For renewable developments we will focus on expected capacity additions while not directly investigating the specific support policies for renewables (see Section 4 for details).

3. Methods and data

To be able to investigate the impact of different support and carbon policies on the NPPs in the New York system, a bottom-up economic dispatch model of the NYISO market area is developed. Following we will shortly present the basic mathematical model formulation, the underlying data structure, and the model calibration for the reference year 2018.

3.1. Electricity market model

Various methods have been applied in the literature to assess the market feedback effects of different nuclear generation developments, in particular phase-out assessments. These methods include optimization approaches (Fürsch et al. 2012; Haratyk 2017; Blumsack 2018), equilibrium models (Nakata 2002; Glomsrød et al. 2015), and system dynamics (Kunsch and Friesewinkel 2014). For our own assessment we will rely on an optimization approach, building a cost minimizing dispatch model of the NYISO zonal system and its neighboring electricity markets. Conceptually, the economic dispatch model identifies the least cost generation portfolio to satisfy a given total load subject to a set of technical constraints. The key advantage of such models is that they provide an efficient computational tractability which allows them to handle complex electricity market problems (Ventosa et al. 2005).

In comparison to other recent bottom-up dispatch model applications for North America (Haratyk 2017; Tsai and Gülen 2017), our model is unique in the sense that it represents the NYISO system at a relatively high spatial resolution by incorporating the eleven internal New York Control Area (NYCA) zones as well as the four major neighboring regional electricity markets. The model follows state of the art in electricity market modeling and is formulated as a linear optimization problem in the Julia programming language utilizing the JuMP.jl package as the core optimization architecture and the Gurobi solver.

The objective of the model is to minimize the total operational system costs (i.e., investment costs are neglected and only the marginal generation costs are considered: $mc_{c,t}$) of conventional power plant generation at each hour ($G_{c,t}$). In addition to those total generation costs, the objective function incorporates a penalty for not meeting loads.⁷

$$\min Costs = \sum_{c,t} mc_{c,t} G_{c,t} + \sum_{n,t} cVoLL qVoLL_{n,t} \quad (1)$$

This objective function is subject to several constraints representing the technical characteristics of the system. As electric supply and demand has to be balanced at all times, equation (2) ensures an hourly and zonal energy balance (we follow the formulation used in Leuthold U., Weigt, and Von Hirschhausen 2012). The local energy demand ($d_{n,t}$) as well as the demand by pumped hydro storage units within the zone ($PSP_{p,t} \uparrow$) has to be matched by the total zonal supply provided by conventional power plants ($G_{c,t}$), renewable infeed (wind, solar, and RoR), seasonal hydro storage generation ($SES_{ss,t}$) and the generation from pumped hydro storage units ($PSP_{p,t} \downarrow$). In addition, injection into the grid as well as withdrawals from

⁷ Such a penalty term allows the model to derive a feasible solution even in case of insufficient generation capabilities. We assume a fixed level for the value of lost load, set at \$250/MWh.

the grid can be used; specified via the flows over power lines ($F_{l,t}$) and the respective network topology as specified via the incidence matrix $\mathbf{i}_{n,l}$.⁸ Finally, in case of supply shortages the model can use an ‘energy not served’ variable ($qVoLL_{n,t}$) to ensure a balance. The energy balance equation is used to extract zonal prices by means of the Lagrangian multipliers. In this case, the multiplier represents prices for each zone n at hour t .

$$d_{n,t} + PSP_{p,t} \uparrow = \sum_{n,t} G_{c,t} + WIND_{w,t} + SOLAR_{s,t} + ROR_{r,t} + SES_{ss,t} \quad \forall_{n \in N, t \in T} \quad (\lambda_{n,t}) \quad (2)$$

$$+ PSP_{p,t} \downarrow - \sum_l \mathbf{i}_{n,l} F_{l,t} + qVoLL_{n,t}$$

Outputs of conventional generators at each hour are limited by their maximum nameplate capacities (\overline{g}_c). Unit commitment aspects (i.e., start-up, shutdown, and ramping) are ignored in this model formulation.

$$G_{c,t} \leq \overline{g}_c \quad \forall_{c \in C, t \in T} \quad (3)$$

The output of renewable generators (i.e., wind and solar) is represented via a simple time series given the hourly availability and the total installed capacity:

$$WIND_{w,t} \leq \overline{wind}_w \times avail_{w,t} \quad \forall_{w \in W, t \in T} \quad (4)$$

$$SOLAR_{s,t} \leq \overline{solar}_s \times avail_{s,t} \quad \forall_{s \in S, t \in T} \quad (5)$$

To accurately capture hydropower generation, we classify and model hydroelectric plants via three distinct types; pumped storage plants (PSP), seasonal storage (SES), and run-of-river (RoR) plants. RoR plants follow the same logic as wind and solar units.

$$ROR_{r,t} \leq \overline{ror}_r \times avail_{r,t} \quad \forall_{r \in R, t \in T} \quad (6)$$

PSP is represented using a simplified storage formulation capturing the pumping ($PSP_{p,t} \uparrow$) and generation ($PSP_{p,t} \downarrow$) logic as used in the energy balance in equation (2) to define the hourly storage level ($PSP_{level_{p,t}}$). In order to account for losses in the system, an overall pumping efficiency parameter (η) is attached to the model (see, for example, Leuthold U., Weigt, and Von Hirschhausen 2012; Weibezahn and

⁸ Note that while all generation variables are positive, the power flows can be both positive or negative. Thus, the nodal flow balance given by $\sum_l \mathbf{i}_{n,l} F_{l,t}$ can be positive (i.e., injecting into the grid) or negative (i.e., withdrawing energy from the grid) as well.

Kendziorski 2019; Dolter and Rivers 2018). Energy storage facilities that operate with either battery or flywheel are treated as PSP plants since they share similar operational characteristics.

$$PSPlevel_{p,t} = PSPlevel_{p,t-1} + \eta PSP_{p,t} \uparrow - PSP_{p,t} \downarrow \quad \forall_{p \in P, t \in T} \quad (7)$$

The respective storage level as well as the pumping and withdrawal amounts are subject to capacity constraints:

$$PSPlevel_{p,t} \leq \overline{psp}_p \quad \forall_{p \in P, t \in T} \quad (8)$$

$$PSP_{p,t} \uparrow \leq \overline{pspump}_p \quad \forall_{p \in P, t \in T} \quad (9)$$

$$PSP_{p,t} \downarrow \leq \overline{psrelease}_p \quad \forall_{p \in P, t \in T} \quad (10)$$

SES is also represented via a simplified approach. Similar to the PSP formulation, the filling level of seasonal storage units ($SESlevel_{ss,t}$) tracks the previous periods filling level and accounting for natural inflows into the storage reservoir and the respective hourly generation ($SES_{ss,t}$).

$$SESlevel_{ss,t} = SESlevel_{ss,t-1} + sesinflow_{ss,t} - SES_{ss,t} \quad \forall_{ss \in SS, t \in T} \quad (11)$$

Both the total storage level as well as the hourly production are again limited by maximum capacities.

$$SES_{ss,t} \leq \overline{ses}_{ss} \quad \forall_{ss \in SS, t \in T} \quad (12)$$

$$SESlevel_{ss,t} \leq \overline{sestor}_{ss} \quad \forall_{ss \in SS, t \in T} \quad (13)$$

Power flows over network lines are constructed based on the DC load flow approach (see Schweppe et al (1988) and Stigler and Todem (2005)). The DC load flow approach is a linear approximation of the full AC load flow model and is considered to be a computationally efficient method of computing line flows (Overbye, Cheng, and Sun 2004). The core DC load flow equation is represented in equation (14) and infers that the power flows over all lines and time-steps ($F_{l,t}$) is dependent on the voltage angles at each node ($\theta_{n,t}$) multiplied by the power incidence matrix ($\mathbf{i}_{n,l}$) giving the network topology and the respective line resistance and reactance characteristics (b_l). We select a reference slack bus at a particular zone (\hat{n}) and assigns its voltage angle a value of zero.⁹

$$F_{l,t} = b_l \sum_n (\mathbf{i}_{n,l} \theta_{n,t}) \quad \forall_{l \in L, t \in T} \quad (14)$$

$$\theta_{\hat{n},t} = 0 \quad \forall_{t \in T} \quad (15)$$

⁹ Note that the actual reference location has no impact on the results. It simply acts as the reference point for the relative voltage angle relations.

In addition, power flows over lines are restricted by their respective line thermal capacities. We do not account for transmission losses.

$$-\bar{f}_l \leq F_{l,t} \leq \bar{f}_l \quad \forall l \in L, t \in T \quad (16)$$

3.2. Data

Given the above model formulation, a large data set based on the New York electricity system is needed to derive meaningful model results. In particular, the power plant related technical and cost data, information on renewable and hydro generation, demand structures, as well as a network representation. Following we will shortly highlight the basic data structure and sources for reference values of 2018.

3.2.1 Power plant data

Data on generation technologies actively operating in the NYISO was obtained from the NYISO load and capacity report (NYISO 2018a). To simplify the formulation and speed up the computational times, we aggregated units of similar technology types, fuels, and parent power plants. Following the aggregation process, all power plants were assigned to a specific zone within the NYISO system.

Total installed generation capacity across the state is 44,652 MW. The bulk of the generation capacity is situated in downstate New York and is primarily driven by fossil-fueled power plants. In contrast, upstate New York is characterized by a considerable share of zero-emission generation facilities, notably hydropower and nuclear accounting for 10% and 8% of total statewide capacity respectively. Data on generation technologies for Hydro-Québec, IESO, ISONE, and PJM were obtained from various sources and aggregated according to technology (see Table A1). Fig. 3 depicts total installed capacity for each of the four markets in the model.

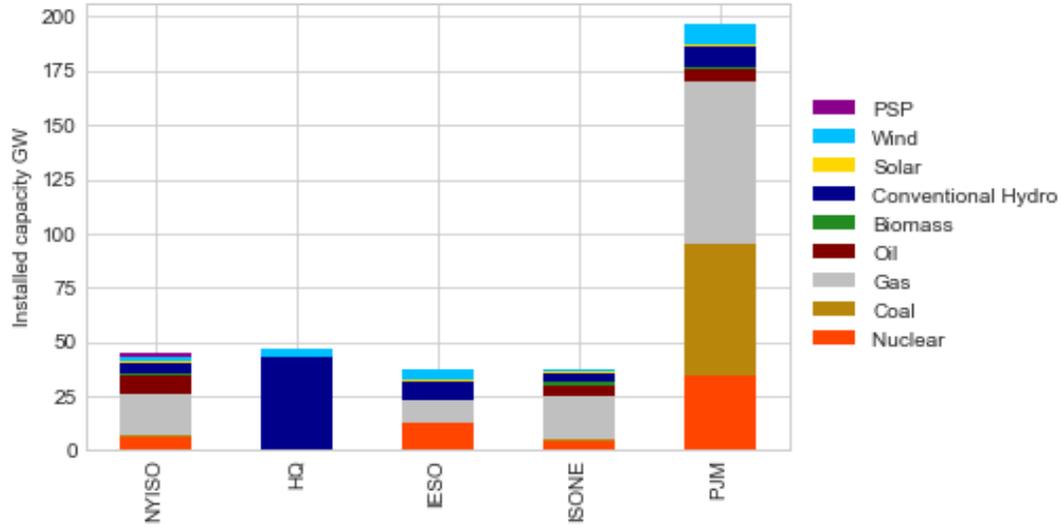


Fig. 3. Total installed capacity based on 2018 values.

Source: Own illustration based on various sources.

3.2.2 Fuel prices and plant costs

Benchmark fuel prices for all markets in the baseline calibration model were assumed to be the 2018 New York yearly average fuel price obtained from EIA state energy data system (SEDS) report (EIA 2022b). Table A2 provides the benchmark fuel prices used in the model. EIA SEDS data was supplemented with detailed monthly plant-level oil and gas fuel prices from the EIA 923 survey data (EIA 2019a) to capture richer plant cost dynamics. This entailed matching plant names in both the plant dataset described in section 3.2.1 and the EIA 923 data. For plants that were not identified, a monthly average price was computed.

For each power plant, overall efficiency levels and marginal costs were calculated based on power plant heat rates and fuel prices¹⁰. Marginal costs for wind, solar, hydroelectric, and nuclear plants are assumed to be zero. An extra cost component is added to the marginal cost formula if a conventional power plant participates in the Regional Greenhouse Gas Initiative (RGGI)¹¹. For the baseline calibration model, we compute the average CO₂ clearing price for the year 2018 (i.e., auctions 39 to 42), which amounted to \$3.42 per ton. Subsequently, fossil-based power plants with a nameplate capacity of 25 MW or greater were

¹⁰ Marginal cost is computed using fuel prices (f_p), plant efficiency (η_p), carbon emission factors (C_f) and average RGGI auction clearing price ($RGGI_p$) as follows; $mc = \frac{f_p}{\eta_p} + \frac{C_f * RGGI_p}{\eta_p}$

¹¹ Although all states in ISONE and some states in the PJM market participate in the RGGI, the individual power plants were aggregated based on technology. We therefore do not include an RGGI cost component for the external markets.

identified and matched with names in the RGGI CO₂ allowance tracking system (COATS)¹² and the CO₂ prices were attached to them.

Conventional plants in NYISO were further classified into three plant cost groupings based on the year of operation, namely, cheap, mid-range, and expensive. The intuition behind this is that older plants are less efficient as compared to newer plants, and hence more expensive to run. To implement the classification, heat rate values of conventional plants were adjusted to reflect different efficiency levels. We selected a 10% adjustment factor and computed high and low heat rates from the average EIA technology specific heat rate values (see Table A3). Since plants were aggregated by fuel type in the external markets, we used average EIA heat rate values.

3.2.3 Hydroelectric modeling

The model classifies all hydropower plants into either RoR, SES or PSP. The hydropower technologies are different in the way they operate in the model and store water. Run-of-river (RoR) plants do not store water and instead generate a consistent output following a step-wise seasonal profile (Dolter and Rivers 2018). Seasonal storage plants (SES) store water in a reservoir using natural water inflows and have flexibility in choosing when to release water. Pump storage plants (PSP) contain pump turbines that pump up water from the lower reservoir to the upper reservoir. Power is generated when water is released from the upper reservoir and flows through the turbines.

Plant classification primarily relied on data from the hydropower reform coalition database (HRC 2021), cross-validated with information from the low-impact hydropower institute database (LIHI 2021). The State of New York has two ‘pure’ PSP plants. The largest is the four-unit 1,160 MW Blenheim-Gilboa Pumped Storage Power Project, located in Schoharie County. The second is the Lewiston Pump Generating Plant (LPGP), a 240 MW PSP located near Niagara Falls. To scale down the model complexity, hydropower facilities were aggregated by type and zone in the model. Although, this aggregation may potentially overestimate the flexibility of hydro facilities, it is a suitable approach as it captures the essential characteristics of the hydropower system, while ignoring granular technical details such as cascade, water delay, and coupling between water nodes (ENTSOE 2019; Rodríguez-Sarasty, Debia, and Pineau 2021).

Historical hydropower generation data from NYISO was decomposed into monthly zonal RoR and seasonal storage generation based on the share of installed capacities. Subsequently, monthly zonal RoR generation was used to compute average hourly capacity factor profiles for all RoR plants.¹³ Likewise, for seasonal storage plants, monthly zonal seasonal storage generation was divided by the number of hours in

¹² Power plant names were identified in the summary level emissions report for 2018 (RGGI 2018).

¹³ RoR plants are assumed to follow a stepwise seasonal profile with consistent generation in each month.

each month to obtain hourly generation values. The values were then used as artificial water inflows into seasonal storage plants, as a replacement for natural water inflow data (see equation 11). While these values may not precisely mirror natural seasonal storage plant inflows, they ensure that the model's output for seasonal storage plants remains within historical generation levels. This approach is consistent with the methodology employed by Dolter and Rivers (2018). Furthermore, we assume all conventional hydro plants in the four external markets operate as RoR plants, integrating an hourly stepwise capacity factor profile. PSP plants in external markets are neglected for computational purposes.

Given that the round-trip efficiency of PSP typically ranges between 65 to 80%, we assume a pumping efficiency level of 75% (Ibrahim, Ilinca, and Perron 2008). PSP operational parameter values (i.e., pumping and generation) were obtained from the International Hydropower Association (IHA 2022). To prevent an empty PSP balance at the end of the year, the model imposes a minimum final storage level equivalent to 15% of the installed capacity (Kazempour et al. 2009). The minimum final storage level at the end of the year is subsequently carried over to the start of the new year. Due to limited data, the maximum storage capacity of the seasonal storage plant reservoir is set at five times the installed capacity value (i.e., the capacity limit in equation 12).

3.2.4 Wind and solar profiles

Variable renewable energy injection is dependent on availability factor profiles. For solar and wind, hourly availability factor profiles were obtained from Renewables.ninja, a web platform that provides simulations of hourly power output from wind and solar plants (Pfenninger and Staffell 2016; Staffell and Pfenninger 2016). To obtain wind availability factors for NYISO, the coordinates of the largest onshore wind plant in each zone were chosen as the zonal reference point. The General Electric (GE) model 1.7 with a hub-height of 80 was selected as the benchmark wind turbine model primarily due to GE's dominance in the U.S. wind power market. In 2020, GE supplied 53% of installed wind power capacity (DOE 2021).

Similarly, for solar plants, zonal reference points were established based on the location of the largest solar PV plant. We assume solar PV panels are fixed and do not track the movement of the sun. This assumption is in line with (Dolter and Rivers 2018). We also assume an optimal tilt angle of 35° for the State of New York. The availability factor profiles were subsequently calibrated to match historical hourly wind and solar generation.

3.2.5 Electricity demand

Electricity demand data for NYISO was extracted from the real-time NYISO database (NYISO 2021b). The database provided data at a five-minute resolution for each of the eleven internal NYISO zones. The data was subsequently resampled to an hourly resolution. To account for external trade, the model integrates exogenous hourly demand data from PJM, HQ, ISONE, and IESO markets. Hourly demand data for the external markets were retrieved from the respective market operator database (see Table A1).

3.2.6 Transmission network and neighboring markets

The model segregates NYISO into 11 zones that directly correspond to the NYISO's official zonal system. A simplified transmission system is adopted, whereby 16 high voltage lines of 230 kilovolt (kV), 345 kV, and 465 kV levels link the internal NYISO zones. To account for cross border flows, we include four neighboring electricity markets, namely PJM, ISONE, IESO, and HQ. NYISO is a net-importer from three markets (i.e., PJM, IESO, and HQ) and a net-exporter to ISONE. In 2021, Hydro-Québec accounted for 65% of total net imports from neighboring markets (Patton, LeeVanSchaick, and Chen 2022). The four markets are modeled as respective single zones (i.e., neglecting inner-market congestion aspects in neighboring markets) with 13 high voltage lines connecting them to NYISO. In total, the simplified transmission system consists of 29 high voltage lines.

Data on line types and flow limits were obtained from NYISO's 2020 reliability needs assessment report and the operating study winter 2021-2022 report respectively (NYISO 2020a; 2021c). The modeling approach is consistent with NYISO commissioned studies (Hibbard et al. 2020; Lueken et al. 2020). Fig. 1 depicts the model representation of the simplified transmission system and locations of active NPPs.

3.3. Calibration model 2018

To test the suitability of the model to reproduce the New York electricity market and to benchmark the model to actual market outcomes, the baseline model is calibrated to 2018. This year corresponds to the start date when upstate New York nuclear plants received the ZECs. This model is used as a basis for the 2021 and 2030 models deployed in the subsequent scenarios (see next section). In terms of generation, the model is capable of replicating NYISO generation patterns closely, with an overall difference of less than 1% throughout the year (Fig. 4). Given that the model is constructed with a detailed representation of gas and hydro technologies, generation from gas and seasonal storage during peak load months is clearly captured¹⁴. Moreover, baseload generation from the three upstate nuclear plants in the model is well represented. However, since nuclear is assumed to run at all hours with no scheduled outages, the model

¹⁴ Comprises combustion turbine, cogeneration, jet engine, and steam turbine.

does not capture the variation in nuclear generation across the months. Generation patterns for the external markets closely match historical profiles, with slight technology-specific variations (see Fig. B2).

Turning to market prices, the model closely simulates NYISO market price dynamics over the entire year as Fig. 5 illustrates. In particular, the price variation between upstate and downstate zones is also well represented. Furthermore, the model can reproduce the January 2018 price spike that was largely driven by the January 2018 North American Blizzard. The blizzard caused a 60% increase in natural gas prices and a significant surge in electricity demand (Malik 2018). Market prices for ISONE and PJM match historical trends with slight variations (see Fig. B1). However, market prices for IESO and HQ diverge away from historical trends. This could be due to the deterministic nature of the dispatch model (especially for the hydro dominated HQ system) and the neglect of conventional plant operational details such as start-up costs and ramping restrictions which would have yielded richer price patterns.

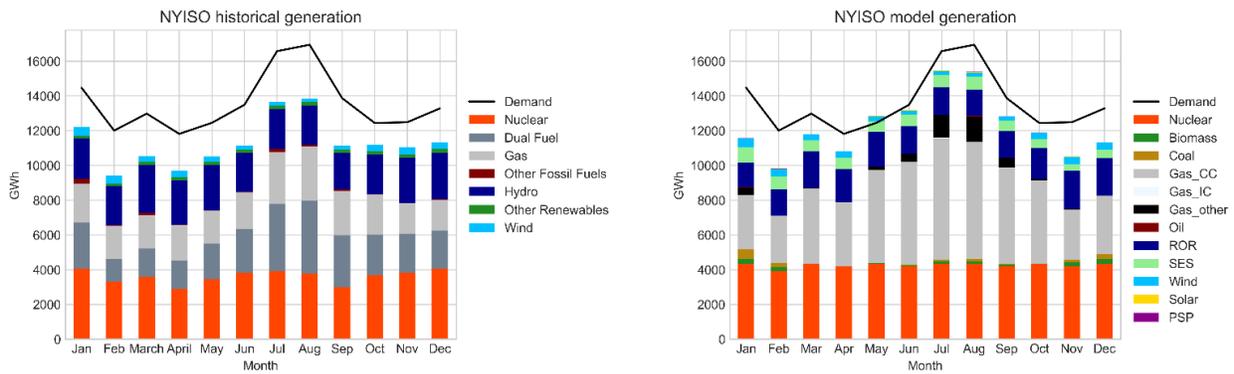


Fig. 4. Comparison of NYISO historical generation and model results.

Note: Gas_CC and Gas_IC refer to combined cycle gas turbine and internal combustion turbine respectively. Gas_other comprises several gas technologies including combustion turbine, cogeneration, jet engine, and steam turbine.

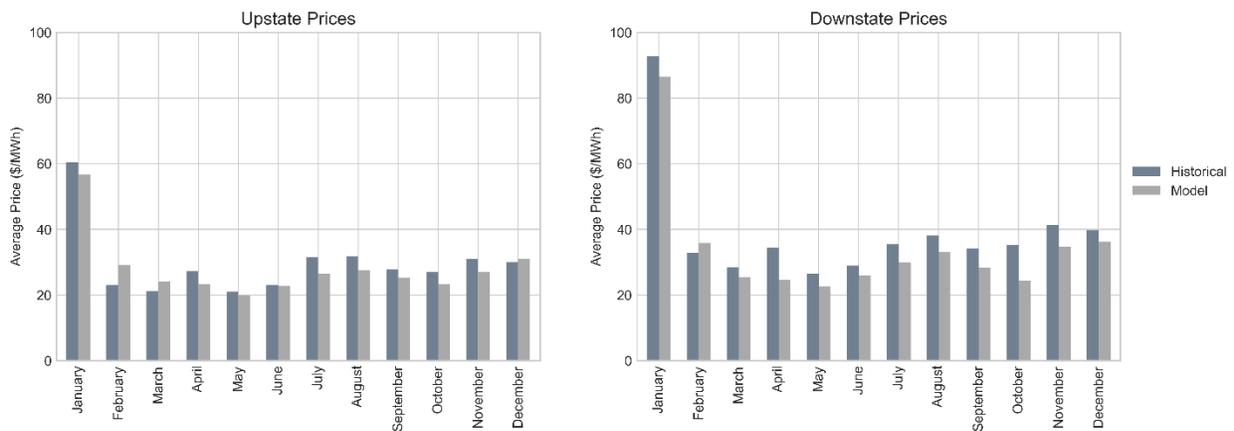


Fig. 5. Monthly average zonal prices for New York State.

In terms of cross-border flows, the model is adept at reproducing cross-border flows to and from NYISO considerably well (see Fig. 6). As elaborated earlier, NYISO is a net-importer from IESO, HQ, and PJM and a net-exporter to ISONE. Comparing the aggregate values, both the import and export values are in line with historic structures albeit not perfectly in line with the respective absolute values. The model underestimates import values from HQ (3 TWh), PJM (4.3 TWh) and ISONE (0.6 TWh) and overestimates exports from NYISO to IESO (250 GWh), Hydro-Québec (300 GWh), PJM (1.2 TWh), and ISONE (1 TWh).¹⁵ The divergence from historical trends is likely due to the combination of a simplified cross-border network and an average plant cost structure for the external markets. Integrating a detailed network grid and factoring in detailed plant cost profiles would improve the cross-border flows significantly but come at significant data and computation costs.

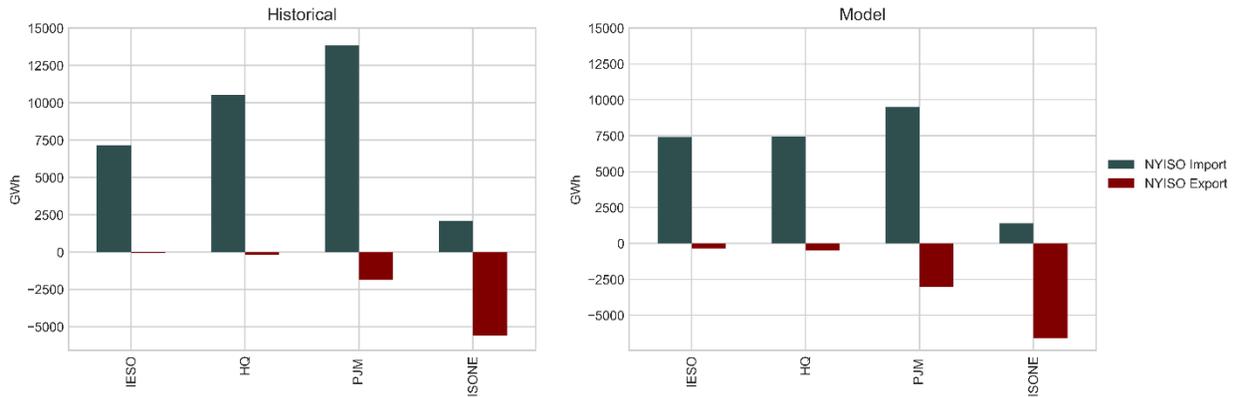


Fig. 6. Comparison of New York State historical and calibration model transmission flows.

Overall, the calibration model is well aligned to actual market outcomes and showcases that the chosen model structure is a suitable foundation for an assessment. However, one needs to account for the underlying limitations when interpreting the results. In particular, the stylized plant and cost structure coupled with a simplified hydro representation will lead to flatter cost dynamics than real world conditions. Thus, price spikes and valleys will be smaller in the model results and can lead to under- as well as overestimating revenue prospects. As the focus of our investigation lies on baseload operated nuclear units, the hourly dynamics are usually less important as long as the resulting yearly average market prices are

¹⁵ The values in parentheses represent the difference between model results and historical statistics.

sufficiently close to real market results. This is the case for our calibration year, and we expect the future scenario assessments to be sufficiently close to this dynamic, even in cases of higher renewable shares.

4. Scenario design

The main objective of our paper is to identify the interplay of different policy choices and the income structure of New York's NPPs resulting from the wholesale market dynamics. To this end we design a scenario structure that allows us to perform several counterfactual simulations focusing on the ZEC scheme as well as carbon price policies. Those results will then be used to identify whether there are potential income shortfalls that could also translate into the nuclear decommissioning stage. Following we will present the ZEC and carbon scenario design as well as the underlying data adjustments to the 2018 baseline model for the different scenarios.

4.1. ZEC policy scenarios

In a first scenario set, we aim to assess the cost benefit structure of the implemented ZEC policy in New York. As the objectives of the ZEC program is to ensure the financial viability of the New York NPPs, we perform a set of nuclear phase-out cases both for the current system (i.e., our 2018 baseline as well as an adjusted 2021 dataset) and for a prospective future 2030 system. In particular, we perform a comparison between a full-phase-out, an upstate- and downstate-phase-out, respectively, and a no-phase-out setting. For the 2018 and 2021 cases we assume no new generation capacity build-up and shortfalls in nuclear generation capacity should be met by an expansion of existing generation capacities. This assumption is consistent with the findings of (Jacoby and Paltsev 2013; Roth and Jaramillo 2017). The aim of this assessment is to evaluate the total system costs of an early nuclear phase-out and compare the ensuing costs with the ZEC program. The different phase-out combinations aim to quantify the leverage effects nuclear plants have in the market and compare ensuing system costs to the ZEC policy. This would address two key policy questions. First, how much leverage do nuclear plant owners have in threatening to retire plants prematurely? Second, from a retrospective outlook, would the Indian Point NPP benefit had the upstate NPPs prematurely retired?

For the 2030 assessment, a model is developed that coincides with the ZEC policy phase-out and when the operating licenses for three upstate nuclear reactors will be expiring. The aim is to evaluate the long-term market conditions with and without nuclear. Since the model is static and runs for a single year, it does not model the capacity expansion pathway endogenously. Instead, the model optimizes the dispatch for the year 2030 and we use this as single reference year for our assessment.

4.2 Carbon price scenarios

In a second scenario set, we aim to investigate how different carbon price policies could impact the revenue situation of New York's NPPs. To this end, two sub-scenarios are modeled: a high and a low price scenario. For the high price scenario, the central limit DEC carbon price estimate of \$121/ton is integrated into the NYISO market in 2030. The low carbon price scenario assumes a price estimate at \$51/ton. We follow the approach of (Shawhan, Picciano, and Palmer 2019), whereby conventional power plants that do not participate in the RGGI are charged the gross carbon price. Whereas power plants that participate in the RGGI are charged a gross carbon price minus the 2030 projected RGGI price of \$12.55 obtained from (NYISO 2018c). This approach is consistent with the IPPTF carbon price proposal. The carbon price is only applied to the NYISO market. Renewable plants, nuclear, and biomass plants are excluded from the carbon price charge. Based on the obtained results, the interaction between the carbon price scenarios and existing ZEC policy is also evaluated.

4.3. Scenario data

For the ZEC scenarios, a 2021 model dataset needs to be constructed. On the supply side, power plant data for NYISO was updated using the 2021 NYISO load and capacity report (NYISO 2021a). Likewise, power plants for external markets were updated to 2021 using various sources. On the demand side, actual historical 2021 load data for NYISO and external markets were fed into the model. Fuel price data were obtained from the EIA State Energy Data System (SEDS) and supplemented with plant-level data reported in the EIA 923 report (EIA 2022a; 2023b). The EIA SEDS data was used for the external markets. Renewable plant availability factors remain consistent with the 2018 model.

For both the ZEC and carbon scenarios a 2030 model dataset is needed. Two key data sources were utilized to construct the future supply side of the NYISO market. The first is the New York State 2030 renewable energy targets introduced in the 2019 Climate Leadership and Community Protection Act (CLCPA). The CLCPA established an ambitious mandate of achieving 70% of electricity generated from renewable sources by 2030 and reducing GHG emissions in the electricity sector by 100% by 2040 (PSC 2020). To accomplish the mandate, the CLCPA incorporated technology-specific capacity expansion targets covering solar PV, offshore wind, and energy storage.¹⁶

In a recent study, the NYISO estimated that to reach the CLCPA targets, the State would need to deploy an additional 20 GW of renewables between 2022 to 2030 (DiNapoli 2023). Therefore, the official CLCPA

¹⁶ Specific targets include, installing 10 GW of distributed solar by 2030, expanding energy storage to 3 GW by 2030, and expanding offshore wind capacity to 9 GW by 2035. The targets were added to the 2021 model to produce a 2030 resource portfolio as shown in Table A4.

renewable targets is supplemented with information on new contracted renewable projects that are under construction and expected to be deployed by 2030 as Fig. 7 illustrates. Data on solar and wind projects in the pipeline were extracted from NYSERDA’s Renewable Energy Standard (RES) Tier 1 bid solicitations from 2018 to 2021.¹⁷ Likewise, for the external markets, renewable capacity targets for 2030 were obtained from various sources and implemented in the model. Table A4 provides the 2030 resource portfolio for NYISO and external markets. On the demand side, hourly demand profiles from 2021 were scaled to match projected demand statistics for NYISO and external markets.

Long-term fuel price projections for 2030 were obtained from the EIA Annual Energy Outlook 2023 report (EIA 2023a). Fuel prices generated from the reference case projections for the electric power sector were utilized as the basis for all markets in the model.

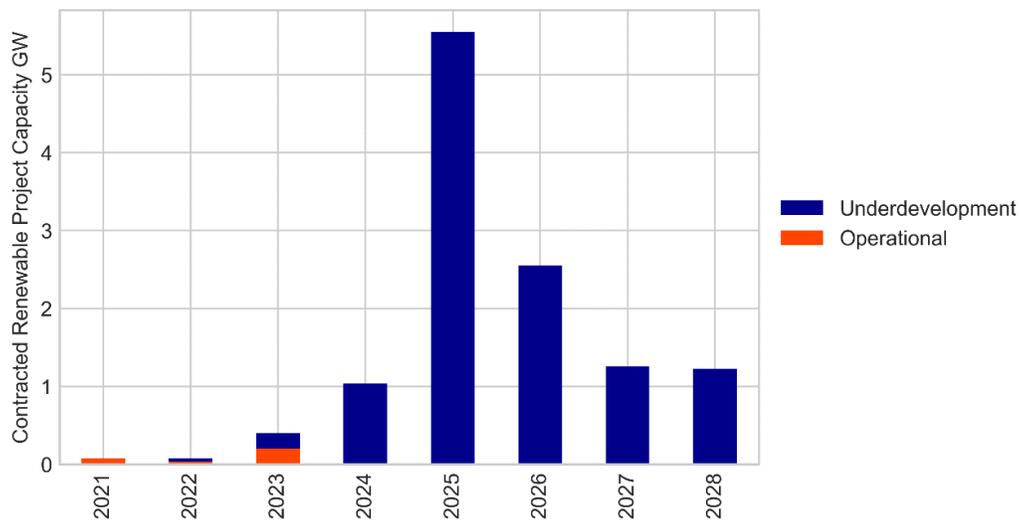


Fig. 7. Contracted new solar and wind renewable projects in New York State (2021-2028). Source: (NYSERDA 2023).

5. Results and discussion

The results of this paper are separated into three sub-sections. The first subsection discusses the results of the ZEC assessment and is further separated into a short-term and long-term assessment. The second

¹⁷ The RES is a mechanism that was introduced in the clean energy standard (CES) alongside the zero-emission credit (ZEC) program. Under the RES, NYSERDA issues annual request for bids from new large-scale renewable resources, known as Tier 1 resources and procures renewable energy certificates (RECs) and offshore renewable energy certificates (ORECs) (PSC 2020; NYISO 2022a). In turn, load serving entities (LSEs) are required to purchase the certificates from NYSERDA based on the share of their load.

subsection explores the long-term market impacts of two different carbon price estimates. The third subsection provides insights on the income implications and links this to the financing of nuclear decommissioning.

5.1 ZEC assessment

5.1.1 Short-term assessment

One of the main concerns that led to the implementation of the ZEC program was the fear that otherwise the NPPs would be shut down and leave the market. As our scenarios show, such an abrupt shutdown of NPPs substantially alters the New York State generation mix. Fig. 8 shows that the reduction in nuclear generation under various phase-out scenarios for the 2021 setting is replaced by an expansion of combined gas cycled generation (GasCC). For instance, phasing out upstate nuclear plants that are currently subsidized with the ZEC scheme reduces nuclear generation by 77.8% and simultaneously increases GasCC generation by an estimated 37.6% from a baseline generation of 57.9 TWh to 79.6 TWh. A complete phase-out of NPPs increases GasCC generation by an estimated 48.3%. The results are consistent with Berkman and Murphy (2015) who estimated a 40 to 54% increase in natural gas generation after phasing out upstate NPPs. Additionally, in the days following the retirement of IP2, NYISO recorded a 26% increase in existing natural gas generation filling in the retired nuclear capacity (Zambito 2019).

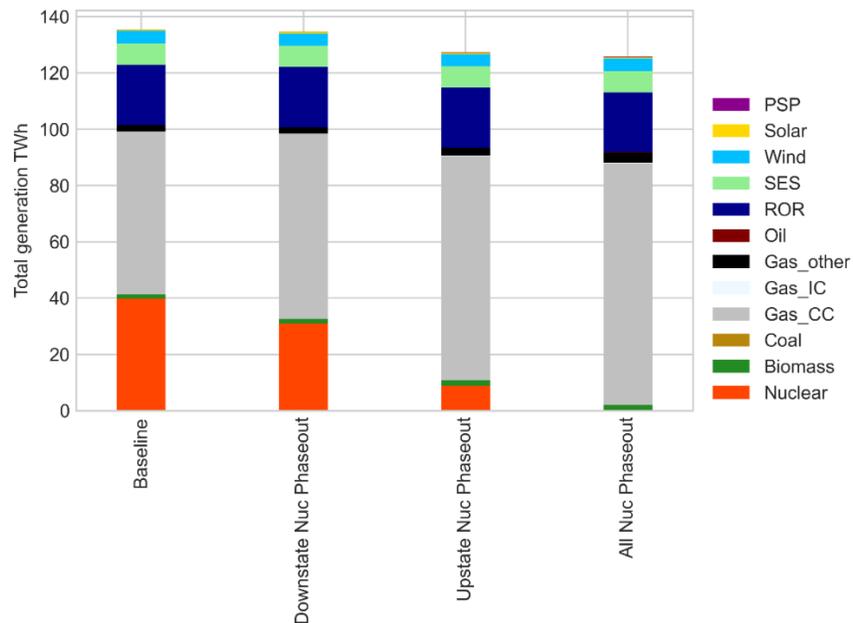


Fig. 8. Comparison of NYISO total generation mix under various NPP phase-out scenarios in 2021.

The expansion of gas generation has spillover implication on NYISO zonal prices. Fig. 9 illustrates that average NYISO prices increases under all nuclear phase-out scenarios, particularly in the winter and summer months. On average, NYISO zonal prices increased by \$0.80/MWh, \$4.74/MWh, and \$4.95/MWh following the retirement of only the active downstate reactor (IP3), upstate reactors, and all nuclear reactors respectively. Since the bulk of existing nuclear capacity is in upstate New York, the magnitude of the zonal price changes is considerable in upstate zones as compared to downstate zones (see Fig. C1). Moreover, the magnitude of price impacts suggests that the Constellation Energy Corporation – being the owner of all upstate NPPs - may have a higher short-term economic leverage when threatening to shut down their nuclear fleet as compared to Entergy owning the Indian Point downstate NPPs. Reversely, Entergy would likely have profited from a phase-out of the ZEC subsidized NPPs, albeit it's unclear whether that would have sufficed in altering their shut-down decision.

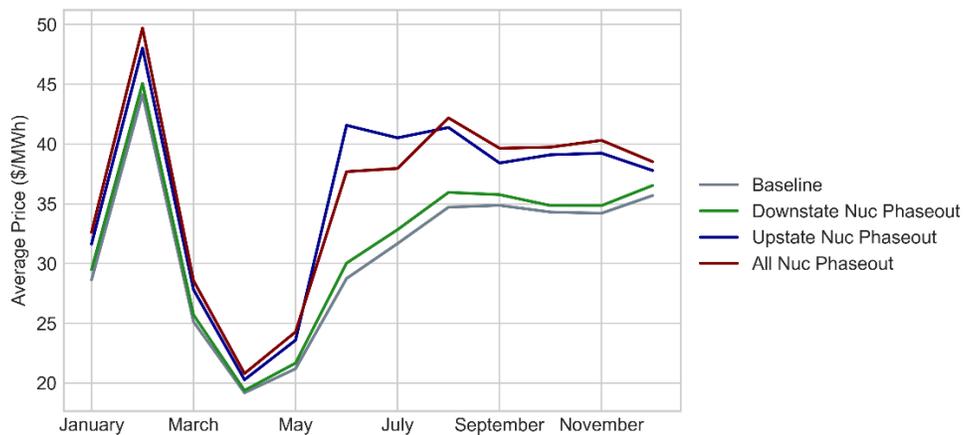


Fig. 9. Average NYISO prices under various NPP phase-out scenarios in 2021.

In terms of cross-border trade, NYISO offsets the contraction in nuclear generation by increasing imports from its neighboring markets (see Fig. 10). Especially the magnitude of imports from PJM increases substantially for the upstate and full nuclear phase-out scenarios. A complete phase-out of NPPs would increase PJM imports by approximately 44% from a baseline of 10.1 TWh to 14.5 TWh. Conversely, exports to neighboring markets reduce across all nuclear phase-out scenarios, suggesting that the system prioritizes domestic demand first before serving external markets. The shutdown of the single remaining downstate NPP has relatively modest implications for cross-border exchanges.

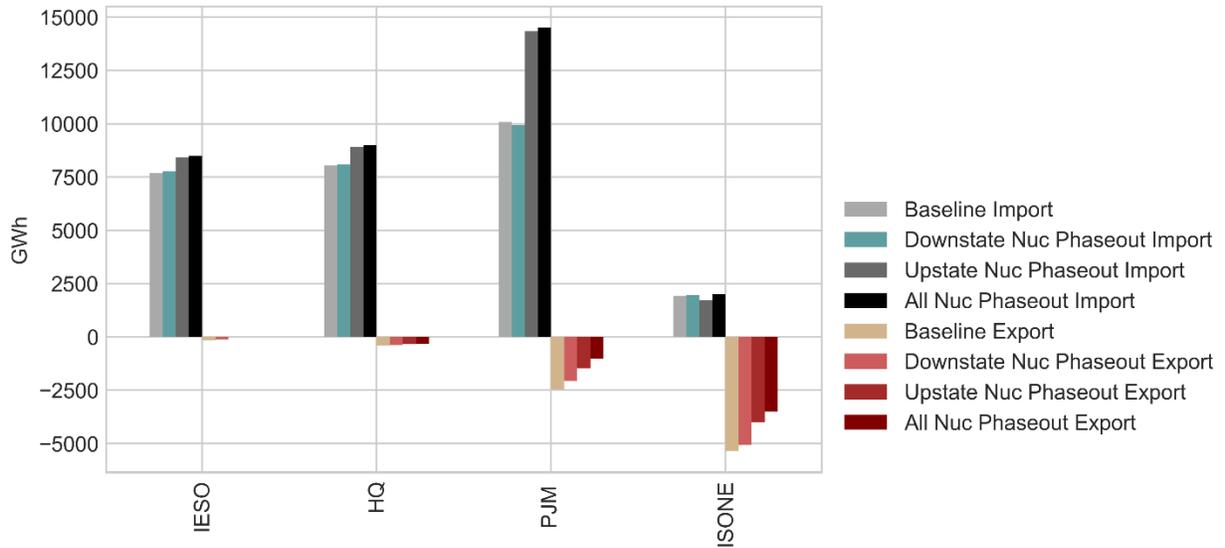


Fig. 10. Cross-border flow comparison under various NPP phase-out scenarios in 2021.
 Note: The reference market is NYISO.

In 2021, the State of New York began to ease lockdown measures following the Covid-19 pandemic. The electricity market was adjusting back to pre-covid levels following the sharp contraction in electricity demand from residential, commercial, and industrial end-use sectors during the height of the pandemic (Le et al. 2023). Therefore, the baseline 2018 year is run in addition to ensure that the obtained 2021 results are not just an outlier due to external conditions. The 2018 results are depicted in Appendix C (Figs C2-C4). In contrast to 2021, two large coal-fired plants with a combined capacity of 977.6 MW were in operation in 2018. Results indicate that phasing-out upstate plants increases coal generation by approximately 53%. Whereas phasing-out all nuclear plants expands expansion of coal generation by 90%. Therefore, an early nuclear phase-out in 2018 would have resulted in a substantial increase in coal generation. Market prices are slightly higher in 2018 compared to 2021, particularly in the first quarter of the year as Fig. C3 illustrates. Moreover, the magnitude of price impacts after an abrupt nuclear shutdown is higher in 2018 compared to 2021. NYISO zonal prices increased on average by \$2.42/MWh, \$3.80/MWh, and \$8.34/MWh following the retirement of the two downstate reactors (IP2 and IP3)¹⁸, upstate reactors, and all nuclear reactors respectively. Furthermore, and in accordance with the 2021 results, NYISO supplements the contraction in nuclear generation by increasing imports from all four external markets, while simultaneously reducing exports (see Fig. C4).

¹⁸ Indian Point 2 (IP2) and Indian Point 3 (IP3) were both operating in 2018. IP2 shutdown permanently in 2021.

Given the market implications of nuclear phase-outs in New York, the question remains whether the ZEC program and its implied prevention was beneficial. Within the ZEC program, only the three upstate NPPs were granted ZEC contracts for a 12-year period from 2017 to 2029. As such, the counterfactual costs of phasing out three upstate NPPs in 2018 and 2021 can be compared with the costs of the ZEC program. The total estimated ZEC expenditure outlays to three upstate NPPs was approximately \$465.5 million in 2018 and \$603.3 million in 2021 (see Table 2). We compare those numbers with the total demand expenses resulting from the wholesale market prices, specifically examining how much consumers needed to pay for getting their electricity (not including grid charges or other levies which should have not been altered by a nuclear phase-out). The reasoning is that both the ZEC payments and the increased electricity generation prices will need to be paid by end-consumers in some form.

The comparison shows that for both years, a full upstate phase-out would lead to market price increases which result in slightly higher total expenses than the payments carried out in the ZEC scheme. Extending the comparison to the other phase-out cases as well showcases some further interesting dynamics. In case of a downstate phase-out, the 2018 additional expenses are slightly lower than the total ZEC expenses. Thus, Entergy Corporation may have had some leverage in the ZEC invitation phase to threaten an even earlier shut-down of Indian Point 2 and 3 to get included. A full phase-out would have led to a significant increase in total expenses for New York consumers. Thus the ‘threat’ of premature NPP shutdown in terms of cost increases for voters is indeed a real concern for policymakers.

In 2021, the situation is a bit different. As only Indian Point 3 remains the threat potential from Entergy is significantly reduced. What is interesting is the slight lower cost level in case of a full shut down compared to an upstate phase-out. Here the network dynamics of electricity system enter the picture. A pure upstate phase-out is altering the generation balance with a strong reduction in the upper system only. In case of a full phase-out, the reduction is more balanced across the system which seems to make the resulting network management easier leading to less congestion. However, as the 2018 results show this is not universally true. Therefore, detailed system assessments are needed to provide situation specific estimates.

Table 2: Comparison of upstate nuclear phase-out costs and ZEC program expenditures in 2018 and 2021 (in \$ million).

ZEC expenditure ^a	Additional consumption expenses ^b		
	Upstate phase-out	Downstate phase-out	Full phase-out
2018			
<i>Fitzpatrick</i> : 114.1	Upstate: 273.2	Upstate: 97.6	Upstate: 534.6
<i>Ginna</i> : 82.13	Downstate: 257.3	Downstate: 292.3	Downstate: 892.0
<i>Nine Mile</i> : 269.33			
Total: 465.56	Total: 530.5	Total: 390.0	Total: 1426.6
2021			
<i>Fitzpatrick</i> : 157.63	Upstate: 564.4	Upstate: 45.7	Upstate: 327.7
<i>Ginna</i> : 100.81	Downstate: 218.4	Downstate: 59.1	Downstate: 401.5
<i>Nine Mile</i> : 344.94			
Total: 603.38	Total: 782.8	Total: 104.8	Total: 729.1

Notes: ^a ZEC expenditures assume a ZEC credit price of \$17.48/MWh in 2018 and \$21.38/MWh in 2021. Expenditure estimates obtained from (Bah 2023a); ^b defined as the differences in total yearly consumption payments between the respective phase-out scenario and the baseline with all relevant nuclear stations in operation.

Overall, the results suggest that phasing out three upstate NPPs would lead to slightly more cost for New York consumers. However, a phase-out is impacting both the consumption and generation side. Thus, while consumers would indeed need to pay more, all of New York’s generators would also benefit from altered market prices, while the ZEC scheme only benefits the three nuclear units. From this perspective the actual benefit picture is less clear. If only consumer (i.e., voter) costs are of concern, the ZEC could be seen as a reasonable policy.¹⁹ If the cost and benefits for all system actors are relevant, the picture is less clear and may indeed be in favor of letting nuclear units phase out to improve the income situation of other providers.

5.1.2 Long-term assessment

The ZEC program is scheduled to run until 2029. To identify the implications of keeping nuclear operational via the ZEC subsidies, we use the 2030 reference year as benchmark. Contrary to the 2018 and 2021 years, the future New York electricity system will be characterized by a higher share of renewables; wind generation increases from 4.37 TWh in 2021 to 16.32 TWh in 2030, and solar expands from 0.52 TWh to 2.01 TWh. In parallel to the expansion in solar and wind generation gas, biomass, and oil capacities are expected to decline. Furthermore, Indian Point 3 is phased out by 2022 and thus only the upstate NPPs

¹⁹ Note that this is only true for the total cost picture. If cost distribution across different consumers is of concern the conclusion may be different.

would be remaining. This system development leads to an altered generation pattern in 2030 as depicted in Fig. 11. Compared to 2021, nuclear generation declines both in absolute and relative terms, renewable generation increases and combined cycle gas generation also slightly increases. Overall, the 2030 system is structurally still close to today’s system.

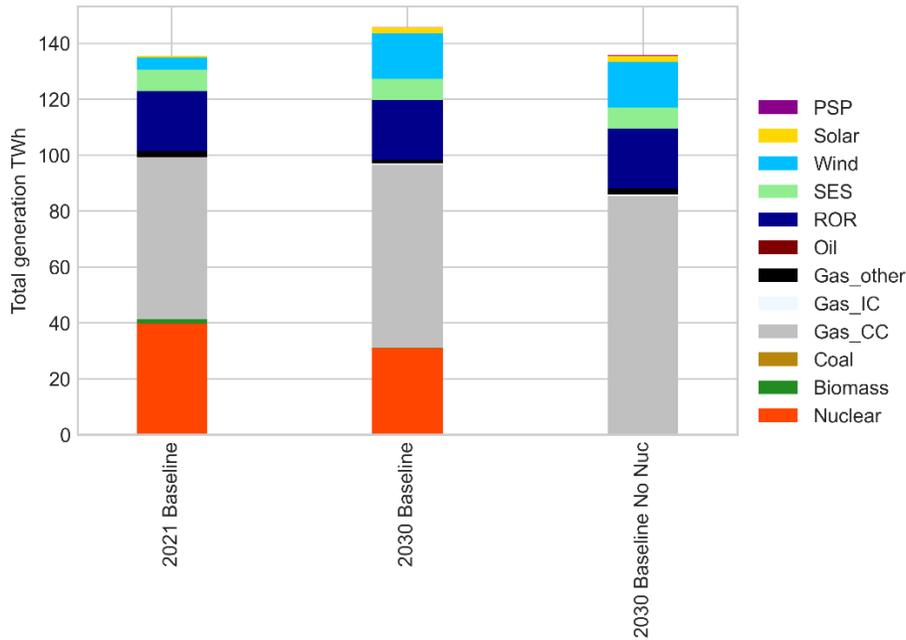


Fig. 11. NYISO generation mix pathway without nuclear up to 2030.
 Note: Refer to Table C1 for detailed results.

Comparing this 2030 baseline setting with a system in which all nuclear stations are phased out showcases a significant increase in natural gas generation technologies. In a nuclear free system, combined cycle gas generation contributes approximately 85 TWh to total electricity generation. Overall generation in New York reduces and the shortfall is compensated with altered cross-border exchange, similar to the 2021 and 2018 cases.

On the price side, the transition towards a higher share of renewables leads to price decline of about \$4/MWh as depicted in Fig.12. A phase-out of nuclear stations pushes prices back up again by \$3/MWh. In total consumer expenses, this means an increase due to the phase-out of about \$460 million which is in a similar range as the 2018 ZEC payments. Surprisingly, the costs of a full phase-out in 2030 costs less than

the 2030 total ZEC expenditure valued at approximately \$813 million. This is primarily due to the nature of the ZEC scheme, whereby payments gradually increase over the subsidy period.²⁰

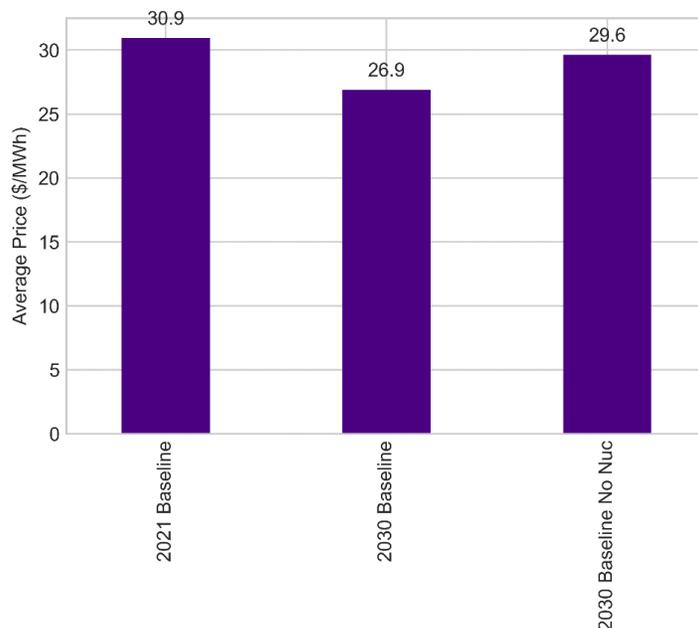


Fig.12. NYISO market price development up to 2030.

Overall, our results indicate that the ZEC program costs are in a similar range as potential cost increases for consumers in 2018 and 2021. However, accounting for distributional effects across different generators and potential further distributional concerns across different consumers, the picture can easily shift in favor or against each of the options. Compared to (Cebulla and Jacobson 2018) – who found out that keeping upstate nuclear plants with the subsidy scheme until 2050 is the most expensive option compared to the costs replacing nuclear with renewables²¹ – our results are less clear cut but do not directly contradict their findings.

5.2 Carbon price assessment

While the ZEC program is formally a support program for carbon free electricity provision (i.e., zero-emission credit), its design is mostly focused on supporting exiting nuclear plants. A carbon pricing mechanism on the other hand is aimed at internalizing the external costs of carbon emissions and thereby support a large spectrum of carbon free generation alternatives. The envisioned implementation of a carbon

²⁰ ZEC payments in 2030 (tranche 6) is estimated to be \$26.26 (Murphy and Berkman 2016).

²¹ Cebulla and Jacobson (2018) estimated that keeping nuclear with subsidies up to 2050 costs \$32.4 billion.

price therefore can be seen as an alternative approach in supporting nuclear generation albeit with a different overarching objective in mind. Assuming the same underlying capacity developments until 2030 as in the above presented ZEC assessment (i.e., increase in renewable capacities, decline in fossil capacities), implementing a carbon price should lead to a reduction in fossil generation compared to a setting without carbon prices. Fig. 13 showcases the 2030 baseline dispatch results as well as the two carbon price settings (a low price of \$51/ton and a high price of \$121/ton) presenting a clear reduction in total gas generation (e.g. gas generation reduces from 60.2 TWh in the baseline to 36.3 TWh in the low carbon price setting) while both nuclear and renewable generation remain at similar levels. This leads to an overall reduction in local generation in New York and a subsequent need for additional imports and reduced exports.²²

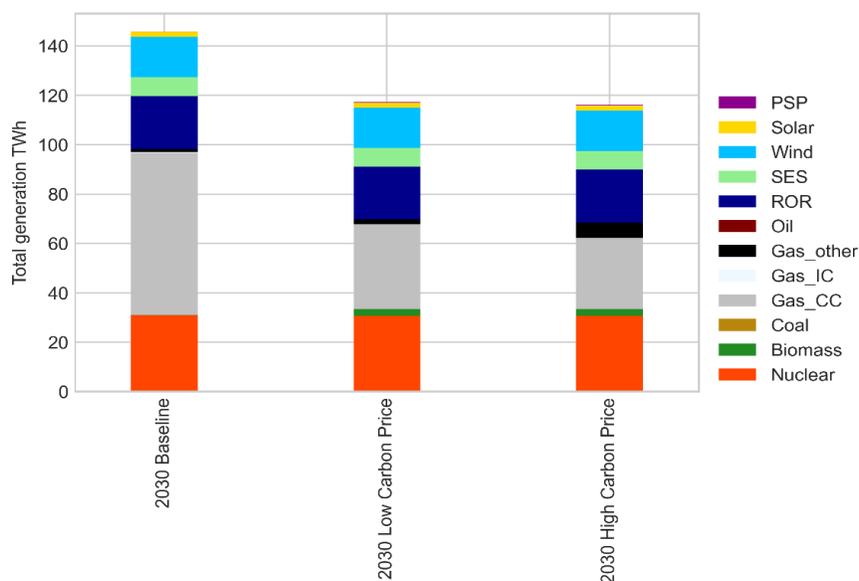


Fig. 13. NYISO generation mix pathway up to 2030 with a carbon price mechanism. Note: Refer to Table C1 for detailed results.

Inevitably, a carbon price mechanism raises the cost of dispatching conventional resources, which ultimately increases average wholesale market prices. Fig. 14 shows that activating a low carbon price mechanism in 2030, increases average NYISO prices by \$24.1/MWh from \$30.9/MWh in 2021 to \$55.1/MWh in 2030. Under this scenario, prices for Zones B and C where upstate NPPs are active, increase by \$17.17/MWh and \$15.54/MWh respectively (see Table C2). This suggests that a low carbon price is

²² Note that the model does not include endogenous investments. Thus the different carbon prices cannot lead to altered renewable capacities.

effective in improving the profitability of upstate NPPs.²³ In a recent report, (Shawhan, Picciano, and Palmer 2019) found that implementing a carbon price of \$51/ton under a low solar and wind cost environment, increases average wholesale market prices by \$21/MWh. Similarly, the Brattle Group estimated that a \$40/ton carbon price would raise wholesale market prices by about \$19/MWh in 2025 (Newell et al. 2017). A high carbon price would significantly raise average NYISO price by approximately \$70.31/MWh from the 2021 baseline and should provide significant incentives for carbon free electricity provision.

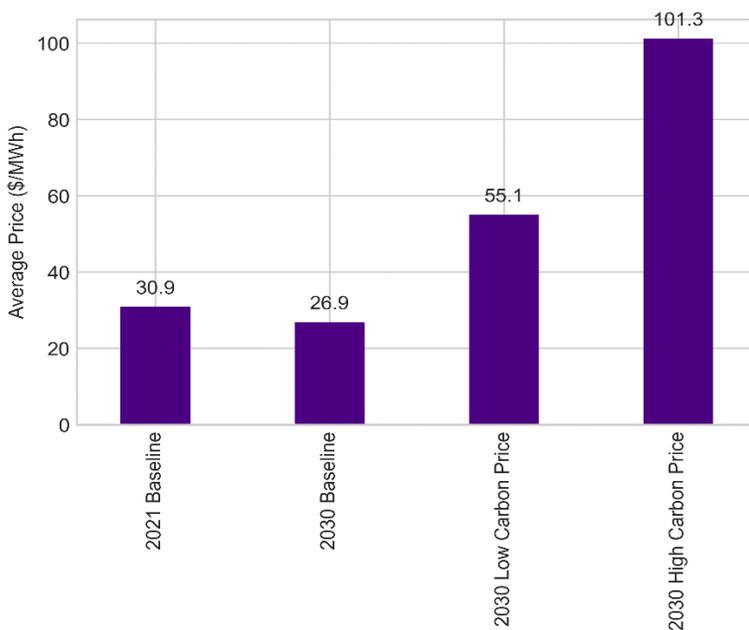


Fig. 14. NYISO market price development up to 2030 with carbon price.
 Note: Refer to Table C2 for detailed results.

While it's obvious that a carbon price would benefit nuclear generation, if the ZEC mechanism is still in place simultaneously it could lead to double benefits. Therefore, the New York ZEC scheme incorporates an adjustment mechanism, which lowers the value of the final ZEC credit price if the combined energy market and capacity price exceeds \$39/MWh. It is therefore crucial to understand how a carbon price mechanism interacts with the existing ZEC policy. Fig.15 shows that a low carbon price of \$51/ton reduces the final ZEC price but does not fully curtail the ZEC price. Whereas a high carbon price of \$121/ton reduces Zone B ZEC price to \$1.40/MWh and fully eliminates Zone C ZEC price. The results therefore

²³ A Nuclear Energy Agency (NEA) report found that a carbon price in the range of \$43-72/ton is optimal in enhancing the competitiveness of nuclear power (NEA 2011).

imply that with lower carbon prices, NPPs are able to draw from both higher energy prices and the out-of-market ZEC scheme, resulting in a respective revenue increase.

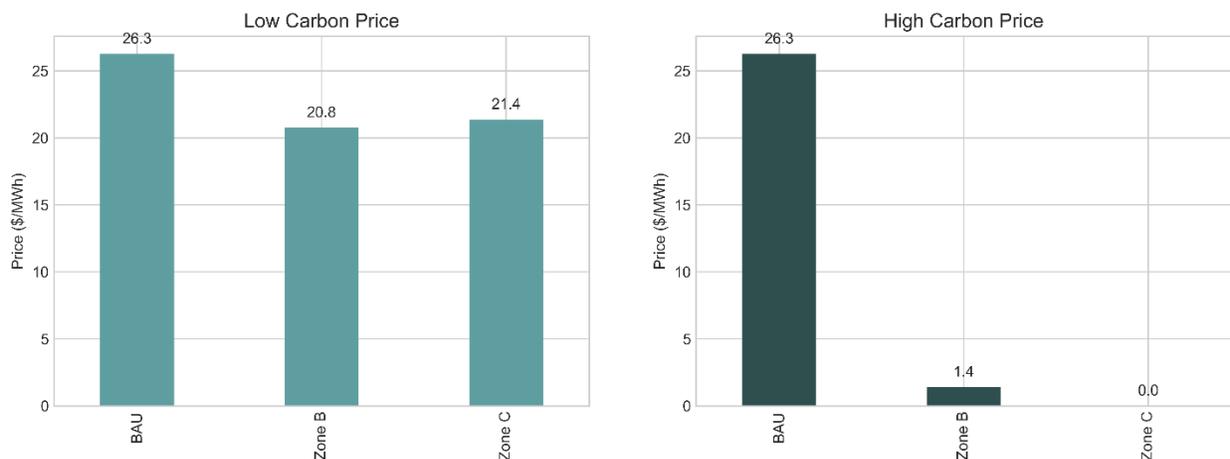


Fig.15. Interaction between a carbon price policy and a business-as-usual (BAU) ZEC scheme in 2030. Note: The BAU ZEC Price is based on 2029 estimate from (Murphy and Berkman 2016). Upstate NPPs are in Zone B and C.

5.3 Nuclear financing assessment

The profitability and threat of premature closure of NPPs not only was an important aspect for the implementation of the ZEC program, sufficient income for NPPs is also crucial for the long-term financing of nuclear decommission. Hence, it is interesting to investigate the income situation of the New York NPPs in the different scenarios. Building on from the carbon price assessment in section 5.2, Fig. 16 compares the profitability of upstate NPPs in 2021 with existing policies and in 2030 with a carbon mechanism in place. Table C3 in the Appendix provides detailed estimates of the nuclear financing assessment. Operating cost data comprises fuel, and operations and maintenance costs (O&M)²⁴ and were derived from annual Nuclear Energy Institute (NEI) cost estimations. Since 2030 cost projections were unavailable, the 2021 estimates were utilized. The NEI cost estimations is widely adopted in nuclear industry profitability assessments (Bah 2023a). The IP3 reactor was not included in the assessment since it retired in early 2021.

The figure clearly shows that a carbon price mechanism significantly improves the financial standing of NPPs in the long-term, primarily through higher market revenues. In 2030, all three upstate NPPs can be assumed to be able to cover their operational costs using only energy market revenues. If the ZEC policy is maintained in 2030 and a low carbon price is implemented, respective profits (i.e., the net difference

²⁴ O&M comprises of several categories such as engineering, fuel management, training, loss prevention, operations, work management, materials and services, and support services.

between total revenues (market and non-market) and costs) are approximately \$351 million (Fitzpatrick), \$247 million (Ginna), and \$815 million (Nine Mile). In contrast, a high carbon price automatically drives down ZEC prices and NPPs benefit solely from high market prices (see Fig.15). In such a case, the potential profits NPPs could make would range from \$247 million (Ginna) to \$824 million (Nine Mile).

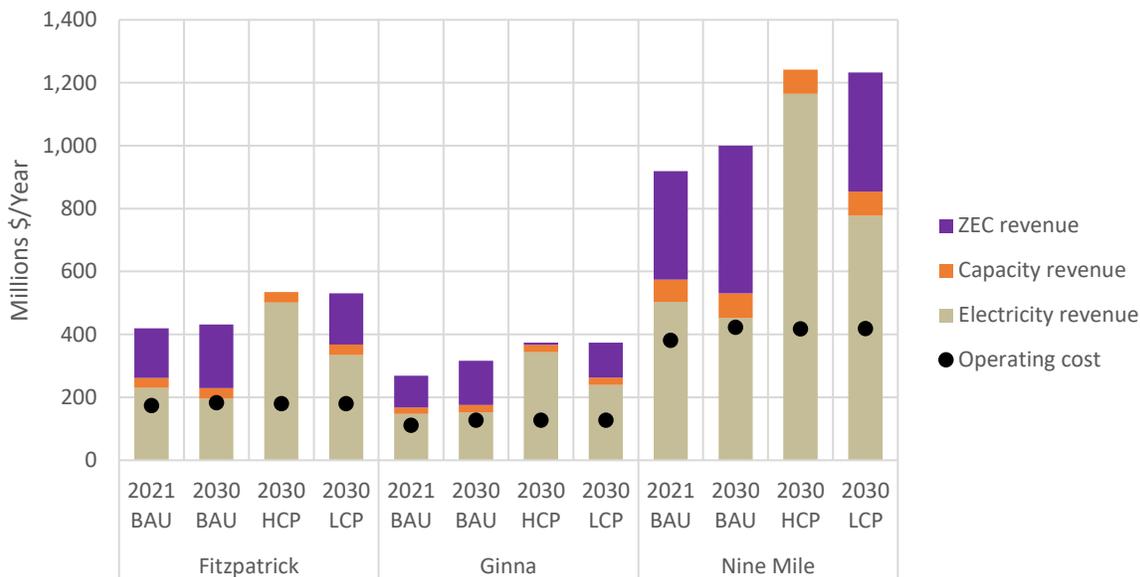


Fig. 16. Ex-post nuclear financing assessment up to 2030.
 Note: BAU: refers to business-as-usual case with existing policy. HCP: High carbon price. LCP: Low carbon price. Estimates for 2021 were obtained from (Bah 2023a).

Albeit highly simplified, the cost and profit assessments indicate that firstly a carbon price greatly benefits nuclear generation and is likely sufficient in keeping them profitable, and secondly that the ZEC subsidies are not strictly needed to ensure operational profit for New York’s nuclear stations. Given that the yearly profits are needed to secure the financing of the decommissioning of the nuclear stations, those profit numbers indicate that in all cases at least some building up of funds seems reasonable.²⁵ Obviously, the implementation of a carbon price would enhance the financing situation. Whether the profits stemming from the ZEC payments are a better option to fill up decommissioning funding or a later stage direct injection of state financed funds (i.e., both are coming from governmental budgets in the end) depends on whether the gradual financing via ZEC income would enable a better fund accumulation. Nevertheless, those numbers should not be considered as direct decommissioning funding values. The companies are still

²⁵ We assume that the New York State NPPs accumulate funds over their operating lifetime. In reality, traditional rate-regulated licensees accumulate funds over their operating lifetime by charging a fee to customers. The remaining licensees provide financial assurances via other means such as prepaid decommissioning funds, surety method, or parent company guarantee. Refer to Bah (2023b) for supplementary details on the U.S. nuclear decommissioning financial regulations.

able to use their income in other ways as well. But obviously higher profits increase the likelihood that sufficient funding is accumulated once decommissioning starts; especially as there is still evidence of decommissioning cost overruns (Bah 2023b).

If the ZEC payments did indeed play an essential role in keeping the upstate NPPs operational during recent years, those subsidies could be seen as a transition payment ensuring that later profits derived from increased carbon prices enable the financing of decommissioning. The resulting financial development and decommissioning of Indian Point 2 and 3 can be seen as potential comparative benchmark. As both units have been shut down earlier than originally planned and are comparable in age to the three older upstate plants, one could assume that with sufficient out-of-market financing they could have been kept operational. If those units face financial trouble during their decommissioning, this could lead to a further argument for the ZEC program. However, a full cost-benefit assessment would only be possible after the decommissioning of the upstate units, at which point the results don't provide meaningful policy advice for the research question at hand.

6. Conclusion and policy implications

The financial viability of operational NPPs has been a major concern in US and European markets in the recent decade. Several U.S. states and the federal government have opted for out-of-market support schemes to maintain the existing NPP fleet. At the same time a long-term transition towards carbon free electricity provision using clear carbon price signals is expected to benefit nuclear. This study evaluates the interplay of market dynamics, support schemes, and nuclear operation for the case of the New York electricity market. Using a bottom-up dispatch model we investigate a set of scenarios representing the local support scheme (ZEC program) as well as the long run carbon price strategies.

Not surprisingly, our results indicate that with a sufficiently high carbon price the revenue prospects of nuclear units can be expected to be positive; both ensuring a viable operation and likely enough financing for the needed decommissioning funding. The impact of the currently implemented ZEC support scheme is less clear. Our results indicate that from a pure payment perspective, the ZEC costs are potentially a bit lower than the resulting increase in electricity expenses for consumers following a price increase if the nuclear units are shut down. However, taking the full system into account the same price increase benefits local generators, and the market price increase is likely structured differently than the rate-payer charges needed to finance the ZEC payments. Furthermore, our cost-revenue investigation for the involved NPPs shows that they likely would have been profitable even in absence of the ZEC payments. Thus, whether the shutdown threats would have been followed through for the upstate NPPs is unclear as well. Finally, given the underlying simplifications and assumptions of the model, the resulting numerical values should not be

seen as perfect forecasts, but be considered as more indicative. Consequently, it is less clear, if the slight cost advantage is a sufficient argument in favor of the New York ZEC program.

To this end, our results are consistent with the findings of (Cebulla and Jacobson 2018) who found that in the long-term, maintaining upstate NPPs with subsidies costs more than permanently phasing them out and replacing them with renewables. Furthermore, the results affirm the position of (Bah 2023a) that the fundamental ZEC design of providing lucrative long-term financial support is likely flawed. Considering that the burden of state support schemes ultimately falls on taxpayers through rate charges, a comprehensive state-level review of the support scheme seems warranted.

Assuming nuclear remains online until 2030 and beyond, the modeling results suggest that a moderate carbon price is an effective mechanism of raising market prices, benefiting all price taking technologies including nuclear. Replacing the existing ZEC program with a consistent carbon pricing policy therefore seems a more consistent strategy given New York's ambitious future energy targets.

Given that many restructured electricity markets with a significant share of nuclear generation have rather similar structures (i.e., aging nuclear reactors, increase in renewable generation, emission reduction targets) and often faced similar concerns about the viability of its NPPs, the results also provide important insights for those markets: if there is a pathway towards proper carbon pricing this should be the preferred way of ensuring sufficient financing for nuclear units.

At the same time the model results clearly indicate that a premature shut-down of nuclear units comes with increased market prices due to the merit order alterations. While this is not surprising, it nevertheless provides a leverage for nuclear operators to put pressure on policy makers. As the interplay of the different components in electricity systems is often non-linear and hard to forecast, such 'threats' should be evaluated with a proper system-based assessment to quantify the potential implications before acting upon them with alterations to policies.

Finally, the results of our revenue assessment linked to the general need for building up sufficient funding for nuclear decommissioning (an issue prevalent in many electricity systems) do showcase a potential reasoning for implementing direct and short-term nuclear support policies. If (1) temporary market conditions do indeed make nuclear operation economically unviable, (2) a premature shutdown is likely, (3) sufficient decommissioning funding is not yet obtained, and finally (4) a carbon price policy is planned to improve the income situation in the future. Under these conditions, a temporal direct support may indeed be a credible policy to keep the units operational and enable accumulation of sufficient funding for decommissioning once the carbon prices push market revenue up. But as is obvious from the number of

needed conditions, this is most likely not the norm but the exception. And in any case, temporal support mechanisms should be clearly linked to market price dynamics to avoid the potential of excessive out-of-market income during solid market times.

Nomenclature

Notation	Description
<i>Indices/Sets</i>	
$n \in N$	Zones
$l \in L$	Power lines
$t \in T$	Time periods
$c \in C$	Conventional plants
$w \in WND$	Wind plants
$s \in S$	Solar plants
$r \in ROR$	Run-of-river plants
$ss \in SS$	Seasonal storage plants
$p \in PP$	Pump storage plant (PSP)
<i>Matrices</i>	
$\mathbf{i}_{n,l}$	Power grid incidence
<i>Endogenous variables</i>	
$G_{c,t}$	Output of conventional generator c in hour t
$WIND_{w,t}$	Wind generation in hour t
$SOLAR_{s,t}$	Solar generation in hour t
$ROR_{r,t}$	Run-of-river generation in hour t
$PSPbalance_{p,t}$	PSP balance in hour t
$PSPlevel_{p,t}$	PSP level in hour t
$PSP_{p,t} \uparrow$	PSP pumping in hour t
$PSP_{p,t} \downarrow$	PSP generation in hour t
$SES_{ss,t}$	Seasonal storage generation in hour t
$SESlevel_{ss,t}$	Seasonal storage level in hour t
$SESbalance_{ss,t}$	Seasonal storage balance in hour t
$F_{l,t}$	Electricity flow over line l in hour t
$\theta_{n,t}$	Voltage angle difference at zone n in hour t
$VoLL_{n,t}$	Lost load
<i>Exogenous parameters</i>	
$mc_{c,t}$	Marginal cost for conventional power plant c for all hours t
\bar{g}_c	Maximum generation capacity for power plant c
$d_{n,t}$	Total electricity demand in zone n in hour t
\overline{psp}_p	Maximum PSP capacity

\overline{psump}_p	Maximum PSP pumping capacity
$\overline{psrelease}_p$	Maximum PSP release capacity
\overline{ses}_{ss}	Seasonal storage plant installed capacity
\overline{sestor}_{ss}	Maximum storage level for seasonal storage plant
$sesinflow_{ss,t}$	Seasonal storage plant hourly inflows
η	PSP pumping efficiency factor
b	Line susceptance
\bar{f}_i	Line capacity limit

Note: Exogenous parameters are denoted in lower case letters and endogenous variables are denoted in upper case letters.

Appendix

Appendix A. Model Input data

Table A1: Power plant and demand data source for 2018 calibration model.

Market	Power plants	Hourly demand
NYISO	NYISO 2018a	NYISO 2018c
Hydro Quebec	Hydro-Québec 2018	Hydro-Québec 2018b
IESO	Ontario 2020	IESO 2018
ISONE	ISO-NE 2018	ISO-NE 2022
PJM	Monitoring Analytics 2019	PJM 2018

Table A2: Fuel price (\$MWh/MMBtu).

Fuel	2018	2021	2030
Oil expensive ^a	53.16	51.39	80.00
Oil cheap ^b	39.31	44.32	60.00
Natural gas	12.83	13.55	10.24
Coal	8.87	7.13	6.67
Biomass	7.57	8.16	8.16
Uranium	2.42	2.18	2.42

Notes: ^aFuel oil No 2, No.3, and kerosene. ^bFuel oil No. 6. For the PJM market, a 10% reduction factor is applied to the fuel prices.
Source: (EIA 2019b; 2023b; 2023a).

Table A3: Power plant heat rate values.

EIA Prime mover	Equivalent model technology classification	Heat rate mid-range plant ^a	Heat rate old plant ^b	Heat rate new plant ^c
Natural Gas				
Steam generator	Steam turbine fossil	10,736	11,809.6	9,662.4
Gas turbine	Combustion turbine			
	Jet engine			
	cogeneration			
Internal combustion	Internal combustion	9,009	9,909.9	8,108.1
Combined cycle	GasCC	7,627	8,389.7	6,864.3
Petroleum				
Steam generator	Steam turbine fossil	10,270	11,297	9,243
Gas turbine	Combustion turbine	13,352	14,687.2	12,016.8
	Jet engine			
Internal combustion	Internal combustion	10,326	11,358.6	9,293.4
Others				
Nuclear	-	10,455	11,500.5	9,409.5
Coal	-	10,015	11,016.5	9,013.5
Biomass ^d	-	13,490	14,839	12,141

Notes: ^aAverage heat rate is based on 2018 values from (EIA 2021) report. All heat rate values are expressed in Btu/KWh

^bHeat rate value for conventional NYISO plants that commenced operations before 1990s. Estimated as 10% above the

average heat rate value. ^cAdjusted heat rate value for conventional NYISO plants that commenced operations in the 2000s.

Estimated as 10% below the average heat rate value. ^d Average heat rate was taken for all biomass plants identified in the

EPA NEEDS v6 2018 database.

Table A4: Modeled 2030 resource portfolio GW.

Technology	NYISO	Hydro- Québec	IESO	ISONE	PJM
Wind	7.41	6.91	5.5	5.5	16.82
Solar	10	0	2.7	11.03	7.25
Energy Storage	4.44	0	0	0	0
ROR	3.37	44.83	9.4	3.91	8.79
Nuclear	3.54	0	8.6	3.3	33.45
Biomass	0.37	0.42	0.4	1.47	0.65
Coal	0	0	0	0	41.87
Gas	20.76	0.41	10.7	16.5	86.72
Oil	9.09	0.13	0	4.4	4.40

Notes: For all markets, renewable energy targets were added to the baseline 2021 model to produce the 2030 resource portfolio. Energy storage is not explicitly modeled for the external markets. Instead, the storage capacity is included in ROR plant capacities.

Source: (ISONE 2010; Acadia Center 2018; PSC 2018; Hydro-Québec 2022; IESO 2022; ISONE 2022; NYISO 2022a; DiNapoli 2023; ISONE 2023; PJM 2023; Wilson, Raman, and Burger 2023).

Appendix B. Calibration

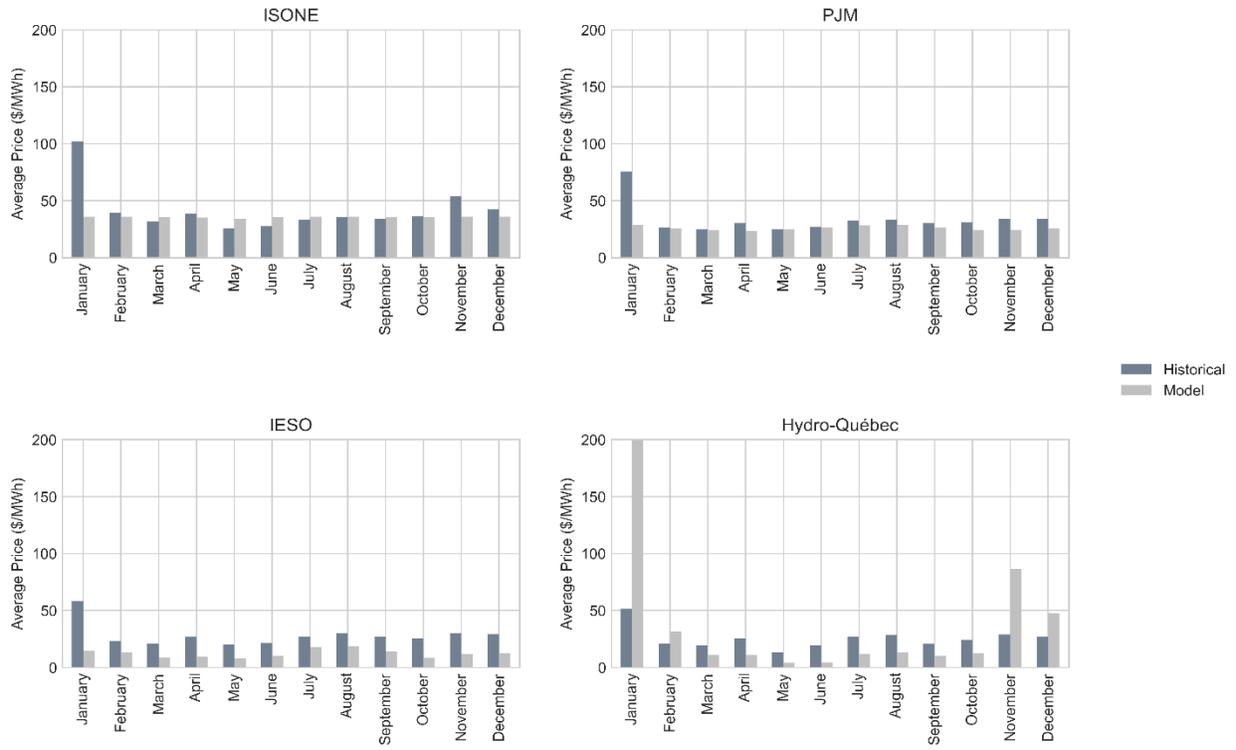


Fig. B1. Benchmarking historical and calibrated model prices.

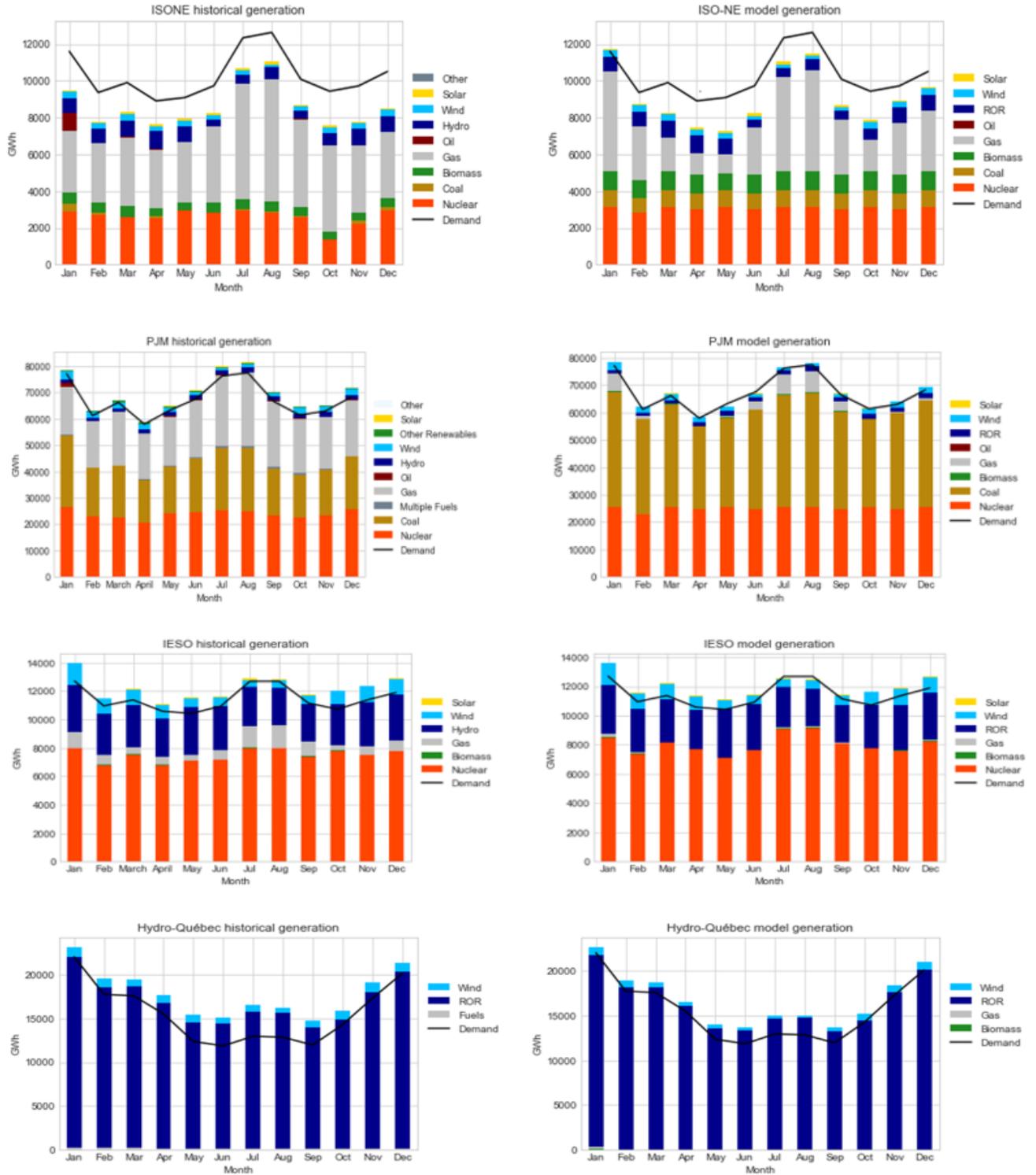


Fig. B2. Benchmarking historical and model generation.

Appendix C. Scenarios

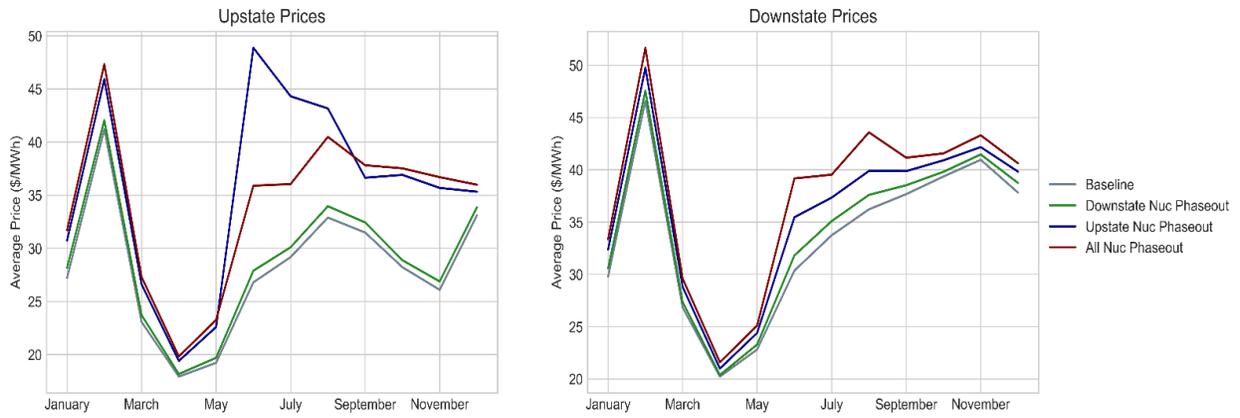


Fig. C1. Average upstate and downstate prices under various nuclear phase-out scenarios in 2021.

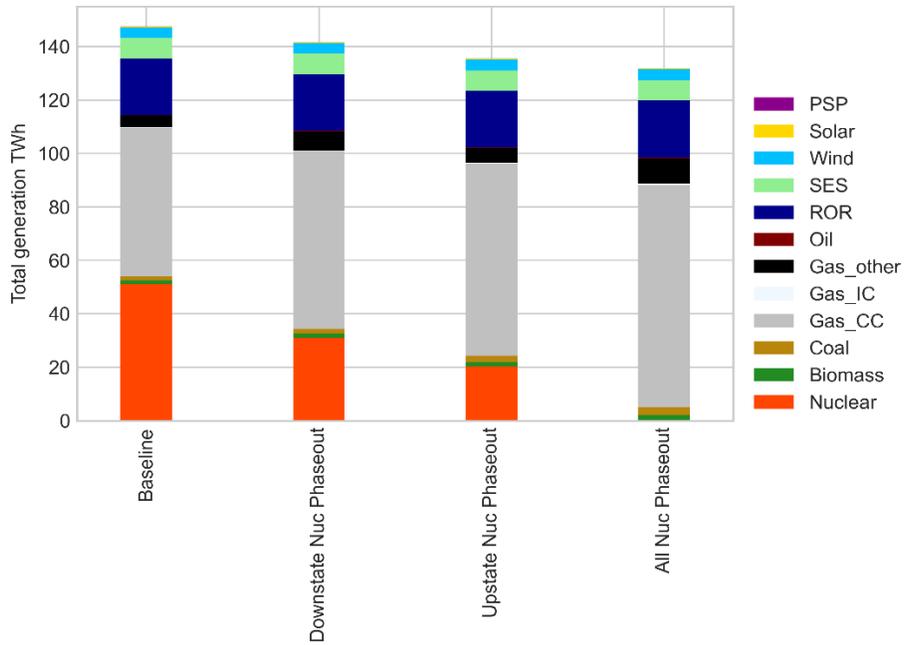


Fig. C2. Comparison of NYISO total generation mix under various NPP phase-out scenarios in 2018.

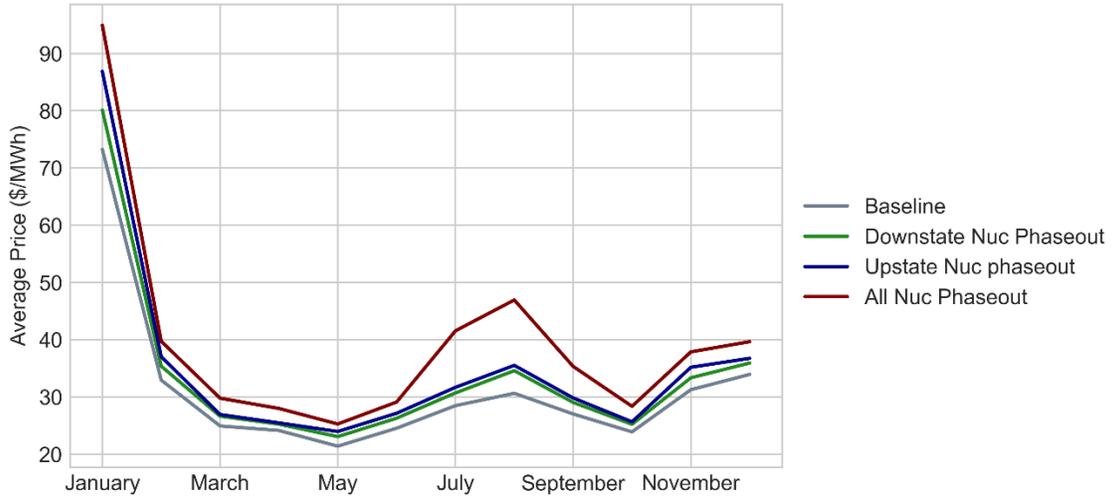


Fig. C3. Average NYISO prices under various NPP phase-out scenarios in 2018.

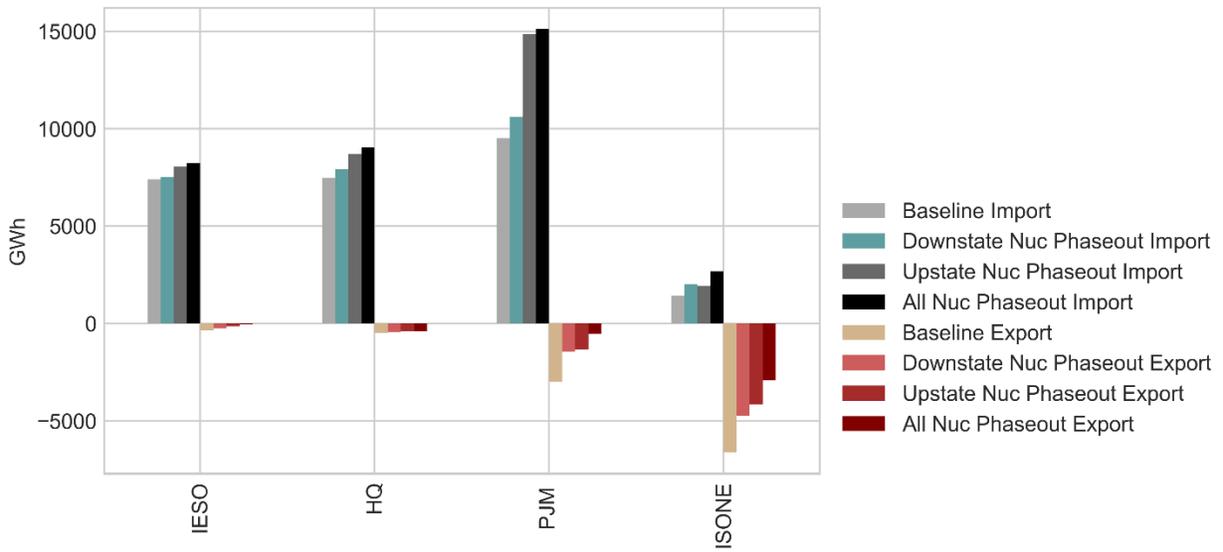


Fig. C4. Cross-border flow comparison under various NPP phase-out scenarios in 2018.

Table C1: NYISO scenario generation results (TWh).

Technology	2021 Baseline	2030 Baseline	2030 Low Carbon Price	2030 High Carbon Price	2030 No Nuclear and No Carbon Price
Nuclear	39.84	30.97	30.71	30.67	0.00
Biomass	1.53	0.10	2.74	2.74	0.23
Coal	0.00	0.00	0.00	0.00	0.00
Gas_CC	57.86	65.37	34.40	28.83	84.97
Gas_IC	0.10	0.53	0.01	0.01	0.83
Gas_other	2.20	1.37	1.92	6.27	2.07
Oil	0.04	0.01	0.02	0.00	0.06
ROR	21.35	21.35	21.35	21.35	21.35
SES	7.59	7.59	7.59	7.59	7.59
Wind	4.37	16.32	16.32	16.32	16.32
Solar	0.52	2.01	2.01	2.01	2.01
PSP	0.09	0.21	0.32	0.33	0.28

Table C2: Average NYISO zonal prices with nuclear (\$/MWh).

Zones	2021 Baseline	2030 Baseline	2030 Low Carbon Price	2030 High Carbon Price	2030 No Nuclear and No Carbon Price
Zone A	26.48	28.15	42.35	58.86	31.73
Zone B	27.33	28.31	44.50	63.87	32.21
Zone C	28.36	25.34	43.89	65.87	28.51
Zone D	28.88	25.35	45.11	68.25	28.64
Zone E	28.73	25.43	44.77	67.66	28.64
Zone F	32.27	26.80	61.14	124.57	28.95
Zone G	32.31	26.93	61.60	124.51	29.12
Zone H	32.56	27.07	64.58	132.50	29.38
Zone I	32.66	27.13	65.77	135.70	29.48
Zone J	35.06	28.02	67.09	138.22	29.85
Zone K	35.79	27.36	65.04	133.81	29.46

Table C3: Ex-post financing assessment for upstate NPPs.

	2021 BAU	2030 BAU	2030 HCP	2030 LCP
Fitzpatrick				
Market only revenue	262,180	229,250	534,560	367,860
Market and ZEC revenue	268,430	316,770	373,980	374,090
Total cost	111,370	127,010	126,920	126,950
Revenue gap- market only	56,250	48,560	239,590	135,550
Revenue gap- market and ZEC's	245,670	249,640	354,750	350,700
Ginna				
Market only revenue	167,620	175,570	366,510	262,500
Market and ZEC revenue	268,430	316,770	373,980	374,090
Total cost	111,370	127,010	126,920	126,950
Revenue gap- market only	56,250	48,560	239,590	135,550
Revenue gap- market and ZEC's	157,060	189,760	247,060	247,130
Nine Mile				
Market only revenue	573,880	530,670	1,241,990	854,470
Market and ZEC revenue	918,820	999,880	1,241,990	1,232,920
Total cost	381,080	422,040	417,710	418,290
Revenue gap- market only	192,800	108,640	824,280	436,180
Revenue gap- market and ZEC's	537,740	577,850	824,280	814,620

Notes: All estimates in \$USD millions. BAU: Business-as-usual. HCP: High carbon price. LCP: Low carbon price.

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