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State and federal nuclear support schemes in dynamic electricity market conditions: Insights from NYISO and PJM

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Abstract

Since 2017, several U.S. states have put in place out-of-market financial support schemes for nuclear power plants operating in deregulated electricity markets. In late 2021, the federal government announced the introduction of two new support schemes to secure the continued operation of nuclear power plants. This policy paper evaluates the profitability of state subsidized nuclear plants in the NYISO and PJM markets over a five-year period between 2017 and 2021. Results indicate that apart from 2019, nuclear power plants were financially robust, relying solely on market revenues without the need for state support schemes. More importantly, the recent upswing in competitive electricity market prices suggests that additional federal-level support schemes are not economically justified in the current market conditions. I provide several suggestions to reconfigure the support schemes to reflect dynamic market conditions and ensure only vulnerable plants are granted out-of-market support.

Keywords: nuclear support schemes, electricity market, excess profit, NYISO, PJM

JEL Classification: H71, Q41, Q48

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1. Introduction

Over the past decade, the expansion of low-cost renewable energy coupled with the drop in natural gas prices led to a gradual decline in wholesale market prices in the United States (see Figure 3). Inevitably, the outlook of many nuclear power plants (NPPs) operating in wholesale markets deteriorated substantially. Between 2013 and 2021, twelve reactors[2], equivalent to 10% of the total installed nuclear capacity permanently shut down, mostly due to adverse economic conditions (Holt and Brown 2022). To counter the short-term withdrawal of NPPs from the markets, several states rapidly introduced legislation to provide direct out-of-market payments to at-risk plants. The subsidy schemes are now in place in four U.S. states covering 19 reactors with a total installed capacity of 19.4 GW. In late 2021, the Biden administration pieced together two new federal level schemes for NPPs with the objective of meeting long-term climate targets. The federal level schemes are currently at various stages of maturity but would guarantee an additional source of revenues for NPPs (see Section 2.2).

The introduction of federal support schemes now is rather puzzling, considering that wholesale market prices have increased substantially due to the uplift in natural gas prices and constraints in electricity supply (EIA 2022b). Theoretically[3], NPPs in wholesale markets should be earning sufficient revenues from the wholesale market to continue operating without the need for state or federal out-of-market support schemes. On that basis, this paper addresses three entwined policy questions. First, is there a valid economic justification for out-of-market support schemes for NPPs in wholesale electricity markets? Secondly, would the coexistence of state and federal support schemes lead to excess profits[4] for NPPs? If so, how can the support schemes be reconfigured to meet the policy objectives of keeping only financially vulnerable NPPs operating while simultaneously negating an excess profit scenario?

To address the first question, I evaluate profitability of subsidized nuclear plants in the New York Independent System Operator (NYISO) and PJM markets over a period of five years between 2017 and 2021. I find that all the NPPs were able to cover their operating costs and generate a modest profit without the need for state support schemes. However, there are isolated periods, particularly in the NYISO market, when nuclear plants must draw upon state subsidies to remain profitable. To answer the second question, I

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[2] Here we distinguish between a plant and a reactor. A reactor refers to a single device to initiate and control a sustained nuclear chain reaction. A nuclear plant may have several reactors on site. The analysis in this paper is on the plant level.
[3] Wholesale markets operate on a cost minimization principle, whereby cheaper units are dispatched first before expensive units. The most expensive units, referred to as the marginal unit (typically natural gas) sets the clearing price for all technologies. However, final prices received by bid-takers (i.e., nuclear, renewables) ultimately hinges on internal market characteristics such as transmission constraints and distance to major load center among others.
[4] Mueller (1977) defined excess profits as profits that are above the norm. The author further asserts that the persistence of excess profits in a market signifies a misallocation of resources.

select 2021 as the hypothetical start date for the federal schemes and assume nuclear plants are granted federal support whist simultaneously retaining state support scheme. I find that the recent rise in wholesale electricity market prices ensures that nuclear plants in both NYISO and PJM markets are financially viable without any state or indeed federal support schemes. If state and federal support schemes coexist, the magnitude of excess profits would be significant. In NYISO, a single federal level scheme alongside the ZEC policy will generate profits ranging between $204 million for the smallest NPP (Ginna) to $699 million for the largest NPP (Nine Mile) annually. In relative terms, this translates to $365,000/MW for Ginna and $369,000/MW for Nine Mile. In the PJM market, I estimate profits would range between $311.5 million for Hope Creek ($266,000/MW) to $672.9 million for Quad Cities ($370,000/MW) annually. Finally, I provide several policy suggestions for reconfiguring the support schemes to negate an excess profit scenario and to reflect dynamic market conditions.

This paper is related to multiple strands in the literature, in particular, the economic challenges facing nuclear plants in competitive markets (Joskow 2006; Lovins 2013; CRS 2016; Szilard et al. 2016) and the ongoing debate on retaining or phasing out nuclear plants (Lovins 2017; 2022; Richards and Cole 2017; Cebulla and Jacobson 2018). Along these lines, a limited collection of papers have investigated the economic viability of nuclear power plants in the U.S. Roth and Jaramillo (2017) for example, estimated the break-even price of electricity nuclear plants would need to cover their long-term costs. The authors demonstrated that nuclear plants relying solely on market revenues and simultaneously operating in a low natural gas price environment would require an additional uplift revenue of approximately $8 to $44/MWh to break-even. Similarly, Szilard et al. (2016) provided a comprehensive profitability assessment for 79 operating nuclear reactors in the U.S. The authors found that in a low market price environment, NPPs face systemic financial challenges in deregulated markets, resulting in a revenue gap estimate of $5 to $15 per MWh. However, the preceding studies do not fully account for revenue streams from state support schemes or the newly proposed federal schemes, thereby potentially underestimating the true profitability estimates of nuclear power plants. Hence, this paper provides a timely contribution on the profitability of NPPs in two major U.S. electricity markets considering both state and federal nuclear support schemes. More importantly, this paper provides suggestions on how nuclear support schemes can be reconfigured to reflect dynamic electricity market conditions.

I have structured the remainder of this paper as follows: In Section 2, I present an overview of existing state level support schemes and federal level policies. In Section 3, I detail the case study, timeframe, and data. In Section 4, I present and discuss my findings. Finally, in Section 5, I summarize my findings and provide policy implications.

2. Overview of state and federal nuclear plant support schemes

2.1 State level support schemes

State subsidy schemes are currently in place in five U.S. states, covering 19 operating reactors with a total capacity of approximately 19.4 GW[5]. The subsidy programs were implemented over a period of six years between 2016 and 2021 and vary in terms of length, costs, and reactors covered (see Table 1). Crucially, all the five states are part of deregulated electricity markets where nuclear power plants are exposed to dynamic market prices and do not receive fixed cost recovery from the state (Schneider et al. 2022). Various reasons were put forth to justify the subsidy legislations including but not limited to, meeting long term state emission targets and mitigating the potential local economic and employment effects arising from a premature nuclear plant retirement (CRS 2016; NEI 2018).

Table 1: Overview of state subsidy schemes

Reactor	Capacity [MW]	State	Market	Age[a]	License expiry	State support scheme	Coverage
Fitzpatrick	813	New York	NYISO	47	2034	ZEC	2017-2029
Ginna	560	New York	NYISO	52	2029	ZEC	2017-2029
Nine Mile 1	613	New York	NYISO	53	2029	ZEC	2017-2029
Nine Mile 2	1,277	New York	NYISO	34	2046	ZEC	2017-2029
Quad Cities 1	908	Illinois	PJM	49	2032	ZEC	2017-2027
Quad Cities 2	911	Illinois	PJM	49	2032	ZEC	2017-2027
Clinton	1,062	Illinois	MISO	35	2026	ZEC	2017-2027
Braidwood 1	1,194	Illinois	PJM	34	2046	CMC	2022-2028
Braidwood 2	1,160	Illinois	PJM	34	2047	CMC	2022-2028
Byron 1	1,164	Illinois	PJM	37	2044	CMC	2022-2028
Byron 2	1,136	Illinois	PJM	35	2046	CMC	2022-2028
Dresden 2	894	Illinois	PJM	52	2029	CMC	2022-2028
Dresden 3	879	Illinois	PJM	51	2031	CMC	2022-2028
Hope Creek	1,172	New Jersey	PJM	36	2046	ZEC	2019-2025
Salem 1	1,169	New Jersey	PJM	45	2036	ZEC	2019-2025
Salem 2	1,158	New Jersey	PJM	41	2040	ZEC	2019-2025
Millstone 2	869	Connecticut	ISO-NE	47	2035	PPA	2019-2029
Millstone 3	1,210	Connecticut	ISO-NE	36	2045	PPA	2019-2029
Seabrook	1,246	New Hampshire	IOS-NE	32	2050	PPA	2022-2029
Total	19,395						

Notes: [a] Age calculated as of 2022. ZEC: Zero Emission Credit, CMC: Carbon Mitigation Credit, PPA: Power Purchase Agreement.

[5] As of February 2023, the U.S. nuclear fleet currently consists of 92 operating reactors with a total installed capacity of 94.72 GW. The subsidy scheme therefore accounts for 20% of total installed nuclear capacity.

The subsidy schemes can be categorized as either direct credit payments or power-purchase agreements (PPA). In the **direct credit payment scheme**, otherwise referred to as the Zero Emission Credit (ZEC), a state regulatory body provides direct monetary premiums to nuclear power plants for each MWh of electricity generated based on an established credit price. State utility companies are subsequently required to purchase their share of the credits from the designated regulatory body and recoup the funds by charging ratepayers. This type of scheme is currently in place in both New York and New Jersey.

In 2017, the State of New York introduced the ZEC scheme as part of the ambitious Clean Energy Standard (CES)[6]. Under the scheme, the New York State Energy Research and Development Authority (NYSERDA) purchases ZEC quantities from three upstate nuclear plants. State electric distribution companies (EDC's) procures the ZEC's from NYSERDA based on the proportion of the electricity load they meet and recover the funds by charging ratepayers up to $0.004/KWh. The ZEC rate is calculated following a formula that is based on the Social Cost of Carbon (SCC) and adjusts upward every two years. The advantage of the direct subsidy scheme is that they can be carefully designed to fill in the missing revenue gap for merchant nuclear plants operating in wholesale markets (Haratyk 2017). The ZEC scheme is expected to cost the state approximately $8 billion dollars over a 12-year period from 2017 to 2029. Similarly, in 2019, the State of New Jersey granted Hope Creek, Salem 1 and Salem 2 reactors ZEC subsidies worth $300 million annually for a three year until May 2022. In 2021, the State extended the subsidy scheme for an additional three-year period until 2025 (Peretzman 2019; 2021). Figure 1 depicts the architecture of a typical state ZEC scheme.

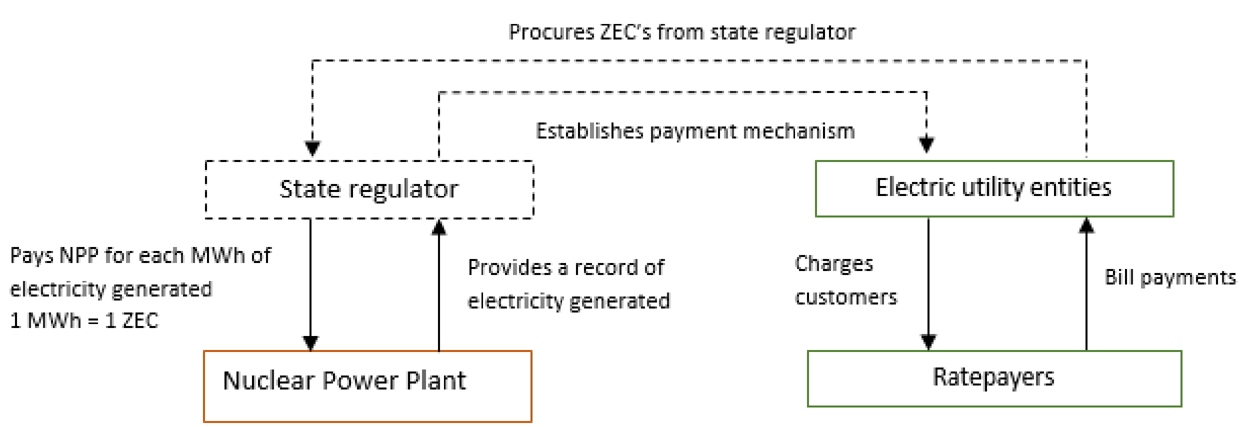

Figure 1. Depiction of a state ZEC architecture.

[6] The CES set a goal of reducing emissions by 40% and ensuring that 50% of the state's electricity is generated from renewable resources by 2050 (NYSERDA and NYSDPS 2019).

Power Purchase Agreements (PPAs) are well-established mechanisms for procuring a certain volume of power at a fixed price over a length of time. PPAs have the effect of shielding power plant owners from market price risks and guaranteeing a fixed revenue stream (Shea and Hartman 2017). In 2018, Connecticut awarded a long-term PPA to Millstone and Seabrook NPPs under the Zero Carbon Solicitation and Procurement Act. In the case of Millstone, two state electric distribution companies agreed to procure jointly 50% the plants annual output over a 10-year period from 2019 to 2029. The agreement permits the distribution companies to recover the costs through the federally mandated congestion charge (FMCC) component on ratepayers bills (Fitzpatrick 2020). For the Seabrook nuclear power station, United Illuminating Company agreed to procure 1.9 million MWh of electricity annually from the plant starting from 2022 until 2029. The State of Illinois implemented a 10-year hybrid PPA-ZEC scheme for the Quad Cities and Clinton nuclear plants. Under the agreement, the Illinois Power Agency (IPA) procures a certain volume of ZEC quantities from the nuclear power plants on behalf of selected utility companies. Each utility company reimburses the IPA for ZEC purchases. It is worth noting that irrespective of subsidy design, ratepayers ultimately bear the full cost of the schemes through hikes in retail prices.

Several lawsuits were filed in New York and Illinois seeking to revoke the subsidy schemes on the basis that the schemes interfered with the operation of the wholesale electricity market and encroached upon the Federal Energy Regulatory Commission's (FERC) jurisdiction on wholesale electricity markets (Murril 2021). In the 2017 case of the *Coalition for Competitive Electricity v. Zibelman*, the district court dismissed the challenge to New York's ZEC program because the plaintiffs failed to demonstrate a link between the ZEC program and wholesale market prices. Similarly, the U.S. District Court for the Northern District of Illinois federal court dismissed two lawsuits against the ZEC program due to the plaintiff's inability to justify their claims[7] (Kulak, Accomando, and Clausen 2018).

The threat of early nuclear shutdowns continues to influence state energy policies to some degree. In October 2021, Illinois passed the Climate and Equitable Jobs Act enacting a second subsidy scheme known as the Carbon Mitigation Credit Procurement Plan (or CMC plan). The CMC plan provides subsidy coverage to the Byron and Dresden nuclear power plants. Following the introduction of the CMC scheme, the owner of both plants reversed the decision to retire the plants. The State of Pennsylvania has raised the possibility of introducing a ZEC scheme to maintain its existing nuclear capacity as part of its long-term

[7] Plaintiffs brought forward lawsuits to revoke the Illinois ZEC scheme based on two key complaints. First, the plaintiffs argued that the ZEC price mechanism is linked to energy market prices, which the Federal Power Act preempts. Second, the ZEC scheme violates the dormant commerce clause, by subsidizing only Quad Cities and Clinton NPPs at the expense of other technologies. For the first claim, the judge dismissed the claim on the basis that states have exclusive authority to regulate in-state electricity rates and charges, which does not fall under the FERC's jurisdiction . The second claim was rejected on the basis that the plaintiffs were not able to trace the impact of the ZEC scheme to alternative technologies (Vill. of Old Mill Creek v. Star 2017).

climate action plan (DEP 2021)[8]. However, in April 2022, the state officially joined the Regional Greenhouse Gas Initiative (RGGI), a regional carbon emission cap and trade program. Fossil fuel plants with a capacity of 25 MW or greater will be required to purchase CO_2 allowances from regional auctions or secondary markets. Conventional plants will then need to factor in the costs of the CO_2 allowances in their wholesale market bids resulting in higher market clearing prices and ultimately improving the profitability of NPPs (Burtraw et al. 2019; DEP 2021). These policy developments in Pennsylvania call into question the need for the state ZEC program that would result in multiple state support schemes for NPPs, particularly if they are also eligible for federal subsidies.

2.2 Federal level schemes

In late 2021, the Biden administration brought forward two new federal schemes to subsidize nuclear power plants. The first scheme, known as the Civil Nuclear Credit (CNC) program was enacted in the Infrastructure Investment and Jobs Act (IIJA). The objective of the scheme is to reverse the trend of NPPs retiring prematurely due to economic conditions (DOE 2022d). Approximately $6 billion will be channeled to the DOE to oversee the program over a five-year period from 2022 to 2026, with the possibility of extending it up to 2031 (DOE 2022d; NIRS 2022). The first application window, which ended in September 2022, prioritized nuclear power plants that were scheduled to shut down prematurely by 2026. Subsequent application windows would be open to all NPPs operating in wholesale electricity markets. In contrast to state subsidy schemes, the final CNC price is based on sealed pay-as-bid auctions[9] and may vary across the nuclear plants. The gradual rollout of the CNC scheme has already motivated licensees to reconsider the decision to shut down reactors. In July 2022, Holtec International applied for CNC credits to restart the Palisades nuclear plant that shut down in May 2022. The plant is currently in Long-term Enclosure (LTE) pending decommissioning and hence this could present a novel regulatory challenge for the Nuclear Regulatory Commission (NRC). [10] Likewise, in September 2022, California passed Senate Bill 846 that repealed the decision to retire Diablo Canyon units 1 and 2 by 2024 and 2025, respectively, in anticipation of the CNC scheme. In November 2022, the DOE selected the Diablo Canyon nuclear plant in the first selection round granting the plant owners conditional credits valued at approximately $1.1 billion (DOE 2022a).

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[8] Nuclear currently accounts for 33% of Pennsylvania's electricity generation mix (EIA 2022a).

[9] Nuclear plants submit sealed pay as bid auctions with a specified price in $/MWh. The bid prices are then adjusted downward to factor in the proportion of nuclear fuel that originates from domestic sources and then ranked from lowest to highest (DOE 2022d).

[10] Refer to Lordan-Perret, Sloan, and Rosner (2021) and Bah (2023) for supplementary details on the U.S. nuclear decommissioning financial and regulatory processes.

In July 2022, the Inflation Reduction Act (IRA) enacted the second subsidy scheme known as the Zero-Emission Nuclear Power Production Credit (NPPC)[11]. The NPPC expands on the 2005 production tax credit policy to include existing nuclear power plants[12]. The baseline credit value is set at $3/MWh and rises to a maximum of $15/MWh if nuclear power plants meet the wage requirement clause (Holt and Brown 2022). The credit value would be reduced to an extent if wholesale market prices rise above $25/MWh and curtailed once market prices reach $43.75/MWh (Schneider et al. 2022). The NPPC scheme is designed to supplement the income of nuclear power plants and would be available for a 9-year period from 2024 to 2032 at an estimated cost of $30 billion (JCT 2022; Schneider et al. 2022). However, unlike the CNC program, the NPPC is still in its infancy and the underlying mechanics have not been clearly established.

To assess the potential for state and federal level support overlap, I identify states with an active support scheme (see Table 1) and states with nuclear plants that would be eligible for a federal support scheme. As is clear from Figure 2, there are multiple states in which nuclear power plants can benefit from both state- and federal level schemes. These five states are home to 23% of the total U.S. commercial nuclear power capacity.

While the scope of this paper is limited to contemporary state- and federal level policy developments, nuclear plants (existing and new) benefit from a range of subsidies and federal loans that encompass the entire nuclear life cycle[13]. Presently, the DOE grants federal loan guarantees[14] of up to $10.9 billion for the construction of new nuclear plants and for advanced nuclear fuel facilities (DOE 2022b). The joint owners[15] of the Vogtle nuclear plant have received up to $12 billion to date in federal loan guarantees for the ongoing construction of the Vogtle Units 3 and 4 reactors (DOE 2019). The Energy Policy Act of 2005 also grants new nuclear plants a subsidy at a fixed rate of $18/MWh that covers the first eight years of operations. Therefore, an updated analysis and review of the entire nuclear subsidy value chain at the local, state, and federal levels is vital moving forward.

[11] The NPPC program was first introduced in the flagship Build Back Better Act (H.R. 5376) that passed the House of Representatives in November 2021, but eventually failed to be signed into law.
[12] The 2005 production tax credit only provides credits ($18/MWh) to new nuclear power plants for the first eight years of operations (Koplow 2011). The tax credit is still active.
[13] Refer to Koplow (2011) for a detailed analysis on the nuclear industry subsidy value chain.
[14] The loan guarantee program is established under Title 17 of the Energy Policy Act of 2005.
[15] Georgia Power, Oglethorpe Power Corporation and subsidiaries of the Municipal Electric Authority of Georgia (MEAG Power).

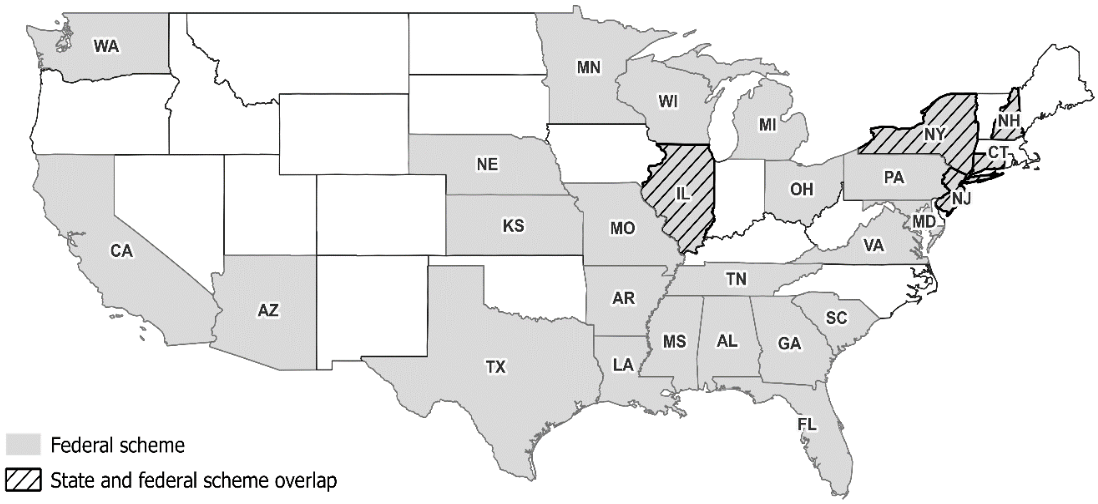

Figure 2. State and federal nuclear support scheme coverage in the U.S.
Note: Federal scheme refers to the CNC and NPPC programs. A state is shaded grey if nuclear plants are eligible for at least one federal scheme. States that are shaded in white do not have any NPPs.

3. Methods

To answer my research questions, I estimate the total revenues of selected NPPs derived from both market payments and out-of-market schemes and compare this with estimated operating costs over a five-year period from 2017 to 2021. Furthermore, to estimate the potential magnitude of excess profit, I select 2021 as a hypothetical start data for the federal schemes, re-estimate total revenues and compare the ensuing estimates with estimated operating costs, holding all else, including electricity demand, constant.

3.1 Case study selection

To answer the key questions of this paper, I investigate 16 state subsidized nuclear reactors in New York, Illinois, and New Jersey. These reactors participate in two competitive electricity markets, namely the NYISO (New York reactors) and PJM markets (Illinois and New Jersey reactors). The NYISO oversees the grid and wholesale market in the State of New York. The state has three active NPPs with a combined installed capacity 3.26 GW, representing 15% of the total state installed capacity. All three plants are in upstate New York, which has historically recorded depressed wholesale market prices. This is partially due to transmission constraints between upstate and downstate New York resulting in marginally higher prices in downstate compared to upstate New York. NYISO's market monitoring unit asserted that ZEC's are vital for the operation of single-unit reactors in the state (Patton et al. 2019). The subsidies provided to the upstate

New York plants are the highest compared with other states and this serves as an upper benchmark when comparing the profitability of NPPs across states and markets. The States of Illinois and New Jersey are part of the PJM market where nuclear accounts for 18% of total installed capacity. A recent study found that the suppressed wholesale market prices pre-2021 significantly eroded the economic viability of nuclear plants in PJM (Potomac Economics 2021). Nuclear reactors in the State of Connecticut and New Hampshire are excluded from the analysis as they are subsidized under long-term PPA contracts that cover a fraction of their annual output. Additionally, details of the contract prices are not publicly available.

3.2 Timeframe

The nuclear profitability assessment spans a five-year ex-post timeframe from 2017 to 2021. This timeframe was chosen for several reasons. First, that start year (2017) directly corresponds to the earliest introduction of the state support scheme (i.e., New York and Illinois) and ensures consistent comparison across states. Furthermore, as elaborated earlier, the early coverage years (2017-2019) coincides with a prolonged period of stagnated wholesale market prices across electricity markets in the U.S. as Figure 3 illustrates. Second, the timeframe is a representative sample of wholesale electricity market trends considering that (i) prices in the pre-subsidy years were also stagnated and (ii) projected prices after the cut-off year (2021) remains relatively high. Hence, rolling back the timespan would not necessarily alter the broad insights of the nuclear profitability assessment. Finally, at the time of writing, nuclear plant operational data[16] for 2022 was unavailable, thereby limiting the analysis to 2021.

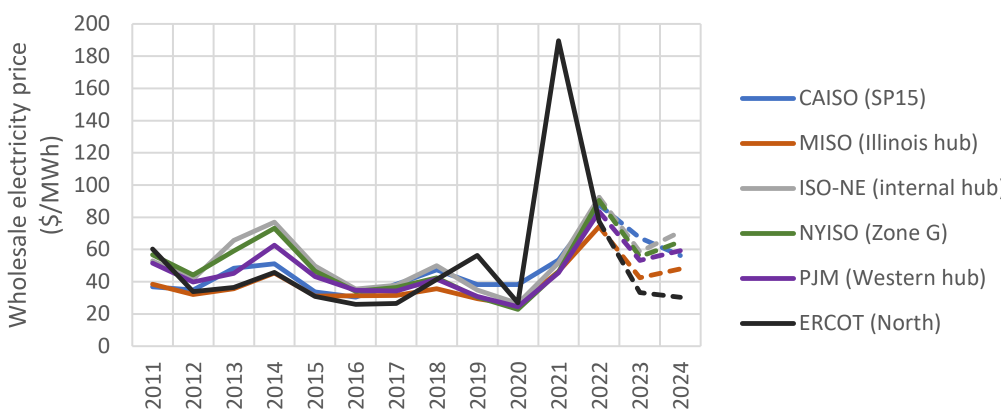

Figure 3. Average historical and projected wholesale electricity prices in selected markets.
Note: Solid line segment represents historical prices and dashed segment represent projections.
Source: (EIA 2023).

[16] This comprises of annual output data and operating costs (see Section 3.3).

3.3 Data

I utilize several publicly available datasets to evaluate the economic viability of NPPs and the magnitude of out-of-market payments. Plant specific historical annual generation data from 2017 to 2021 were retrieved from IAEA PRIS database (IAEA 2022). Merchant nuclear plants rely on the wholesale market and capacity market as their primary sources of revenue, with the former commanding a larger proportion of total revenues (Szilard et al. 2016; Potomac Economics 2021). Therefore, for NYISO, average annual day-ahead prices for central New York zones were obtained from several reports (Patton et al. 2020; 2021; Patton, LeeVanSchaick, and Chen 2022). For nuclear plants in PJM, average day-ahead market prices were obtained from the 2021 state of the market report for PJM (Monitoring Analytics 2022). Similarly, plant-specific capacity market prices for New York plants were obtained from Szilard et al. (2016). For nuclear plants in the PJM market, historical plant-specific capacity market prices were obtained from the 2021 state of the market report (Monitoring Analytics 2022). Evidence suggests that in markets such as the PJM, nuclear plants have managed to consistently clear capacity market auctions, thereby receiving vital revenues (NJBPU 2018). Therefore, I assume nuclear plants cleared the capacity markets in each year and receive capacity market revenues.

Total generation cost is often the primary factor in the decision to continue operating or to retire a nuclear plant prematurely. However, nuclear power plant owners operating in wholesale electricity markets are not obliged to share plant-specific operating costs[17] with the FERC unlike their counterparts in regulated states. Instead, the industry-affiliated Electric Utility Cost Group (EUCG) collates proprietary reactor cost values and releases anonymized national estimates through the Nuclear Energy Institute (NEI) (Lovins 2022). The NEI estimates have been broadly adopted as reference benchmarks to assess the profitability of U.S. NPPs (see Szilard et al. 2016; Monitoring Analytics 2019; Potomac Economics 2021; Monitoring Analytics 2022). Accordingly, annual fuel and operations and management costs (O&M) referred to as operating costs were obtained from several NEI reports (see Appendix A). Capital costs are omitted for two reasons: (i) the reactors in the case study were constructed between the mid-1960s to mid-1970s and would have paid off the capital costs over time. This reasoning is in line with previous studies on the profitability of U.S. nuclear plants (Roth and Jaramillo 2017; Potomac Economics 2021). (ii) All the reactors in the case study, apart from Clinton NPP were granted 20-year NRC license extensions over the past decade and therefore completed license extensions upgrades. The NEI report makes a distinction between operating costs of a single reactor and multi-reactor plant. However, the estimates are based on a small sample of active U.S.

[17] Nuclear power plant costs are treated as confidential since power plant owners submit bids in competitive markets (Szilard et al. 2016). The lack of transparency into plant specific costs hinders detailed analysis into nuclear plant profitability.

NPPs[18]. To counteract a potential bias in the estimates, I use average operating costs for the NPPs in the case study.

To estimate out-of-market revenues, the state ZEC scheme, and federal schemes (i.e., CNC and NPPC) were factored into the analysis. The ZEC prices are based on published ZEC prices for New York (Murphy and Berkman 2016), Illinois (IPA 2017), and New Jersey (Monitoring Analytics 2019). The CNC credit price will ultimately depend on the accepted bidding price and may vary across the NPPs. However, I assume a fixed minimum CNC price of $10/MWh for all the NPPs in the case study. In terms of the NPPC, I take a conservative approach, assuming that nuclear plants would not be eligible for the $15/MWh credit due to state subsidies and instead grant a baseline credit value of $3/MWh. Finally, given the federal schemes will likely commence in 2023, I take the most recent full year (2021) as a hypothetical starting point for the CNC and NPPC scheme.

4. Results

The findings of this paper are divided into three subsections. The first sub-section discusses the profitability estimates for NPPs in NYISO market. The second sub-section extends the analysis to the PJM market covering the states of Illinois and New Jersey. In both sections, the discussion centers around the early subsidy coverage years when market prices were low and the later years when several factors contributed to a high market price environment. The final sub-section compares the relative profitability estimates in both markets.

4.1 NYISO

Results for the state of New York shows that revenues for NPPs are highly susceptible to changes in energy and capacity market prices. In 2017, deep reductions in natural gas prices coupled with an expansion of variable renewable energy sources resulted in depressed wholesale market prices (Mills et al. 2021). Inevitably, market only[19] revenues for nuclear plants, particularly single unit reactors (i.e., Fitzpatrick and Ginna) were considerably less, in comparison to the subsequent years. Despite the downturn in wholesale market conditions, all upstate nuclear plants were able to cover their operating costs and generate marginal profits as shown in Figure 4. Considering market only revenues, net profits in 2017 ranged from $11.2 million for Ginna to $38.6 million for Nine Mile NPP. With the ZEC scheme in place, upstate NPPs earned between $93.3 million (Ginna) to $313.3 million (Nine Mile) in 2017. In 2020, however, results indicate

[18] In the latest NEI nuclear cost report, single-reactor and multi-reactor estimates were based on 20 and 35 plant sites respectively.
[19] Electricity and capacity market revenues.

that Fitzpatrick and Nine Mile were unable to cover their operating costs through market revenues alone and drew upon revenues from the ZEC scheme to remain profitable.

A year later in 2021, high natural gas prices led to an uplift of wholesale market prices across the U.S. and therefore nuclear power plants in deregulated markets were theoretically in a considerably stronger financial position. In New York, the profitability of upstate nuclear power plants improved substantially. Combined market and ZEC revenues far exceed total operating costs for all plants. This suggests that given a moderate to high wholesale market price, upstate nuclear plants would remain highly profitable without a state support scheme in place. However, despite the improved market conditions, the federal government is actively preparing to rollout two new support schemes for nuclear power plants. Assuming (i) the DOE selects upstate New York nuclear plants for the CNC scheme and approves a baseline credit value of \$10/MWh and (ii) the state decides not to freeze the ZEC scheme, the magnitude of profits increases substantially. Taking 2021 as a hypothetical start date of the CNC scheme, results indicate that annual profits for nuclear power plants will range from \$204.2 million for the smallest NPP (Ginna) to \$699.1 million for the largest NPP (Nine Mile). Profits scale upwards moderately if a second support scheme (i.e., NPPC) is activated with a conservative credit value of \$3/MWh[20].

In summary, the results indicate that over long periods, upstate New York nuclear plants are profitable when relying solely on market revenues without state support. However, there are times when market revenues alone would not be sufficient and nuclear plants would require additional out-of-market revenues. The results further demonstrates that an additional federal support layer combined with existing state support would result in a substantial degree of excess profits for the plants.

[20] See Appendix B.

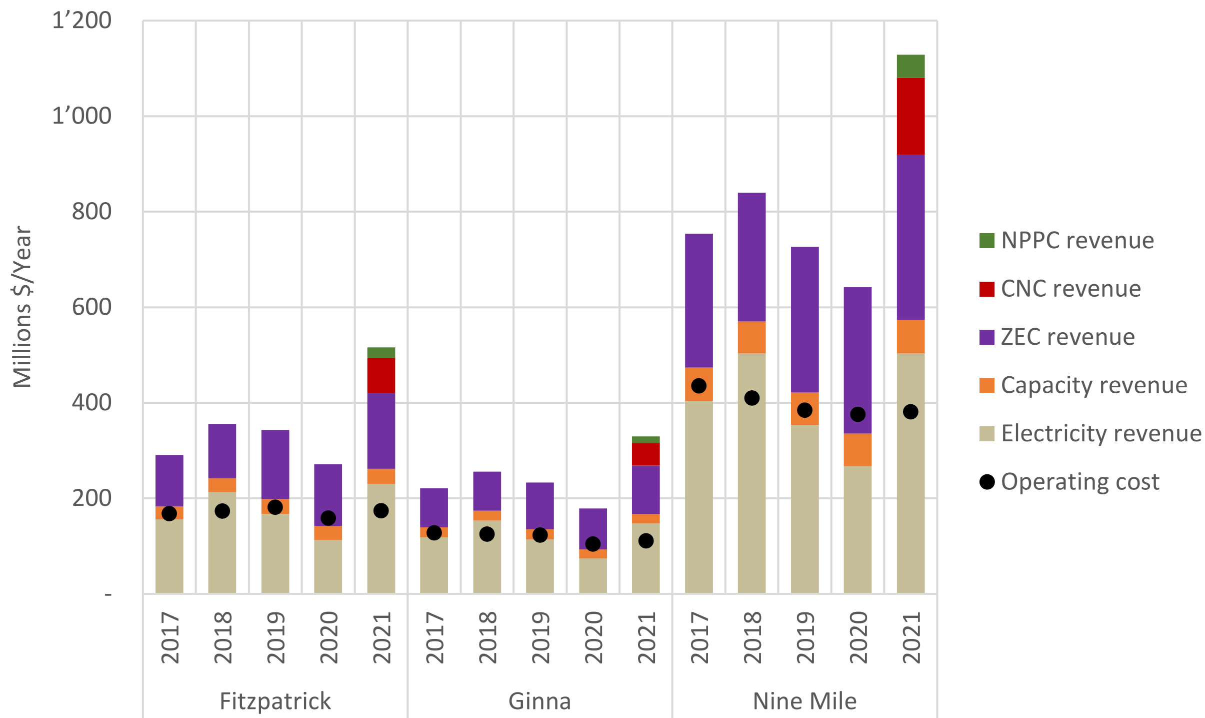

Figure 4. Profitability estimates of nuclear power plants in NYISO.
Note: The black dot indicates estimated operating costs. Plants are earning money in a particular revenue scheme when the color for the scheme is higher than the black dot.

4.2 PJM

The results for the State of New York are not an isolated case per se. Instead, similar patterns emerge when extending the analysis across subsidized nuclear plants in the PJM market. In 2017, the State of Illinois initiated out-of-market payments to Quad Cities and Clinton NPPs. Figure 5 shows that in 2017, market only revenues sufficiently covered total operating costs for both NPPs. Without state support, Quad Cities and Clinton earned approximately \$1.1 million and \$27 million in profits in 2017, respectively. In the subsequent years, both NPPs were in a financially robust condition without the need for state support. Similarly, the State of New Jersey provided ZEC support to Hope Creek and Salem NPPs in 2019. The results clearly indicates that both plants were profitable and at no financial risk pre and post state support. The findings are consistent with the PJM’s independent Market Monitoring Unit’s (MMU) feedback on the ZEC applications for the first eligibility period (2019-2021). The MMU asserted that Hope Creek and Salem are able to sufficiently cover their operating costs from 2019 to 2021 and therefore should not be eligible for state support (Monitoring Analytics 2019). The MMU further claimed that the owners of Hope Creek and Salem- PSEG *“understates forward energy revenues, understates capacity revenues, overstates costs* *and overstates the cost of risk"* in their application for state subsidies (Monitoring Analytics 2019, 5). Moreover, the results corroborate the PJM Power Providers Group's (P3) 2018 assessment that nuclear plants in New Jersey are financially profitable and not at risk of prematurely shutting down (NJBPU 2018). The P3 assessment further argued that the collective evidence from publicly available data will find that the nuclear plants in "*Salem County are solidly profitable and extremely unlikely to close in the next four years - even in the absence of a ZEC payment*" (NJBPU 2018, 3). Unsurprisingly, if a single federal scheme is allowed to co-exist with state support schemes (i.e., CNC), the magnitude of excess profits will be significant for the sub-set of plants in the PJM market. In a single year, profits will potentially range from $311.5 million (Hope Creek) to the highest of $672.9 million (Quad Cities).

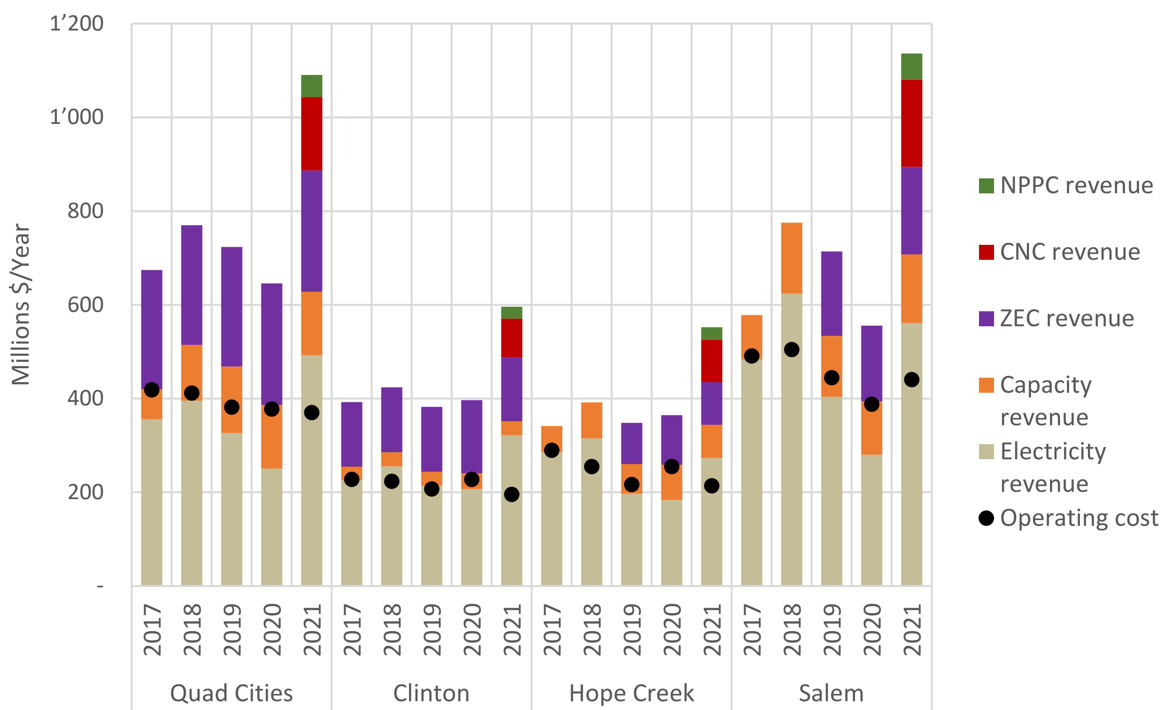

Figure 5. Profitability estimates of nuclear power plants in PJM.
Note: Although Clinton is located in Illinois, it is part of the MISO market.
The ZEC program for Hope Creek and Salem began in 2019.

A sub-set of nuclear plants in Illinois were only granted state subsidies (i.e., Carbon Mitigation Credits or CMC) starting in June 2022. This would allow for a historical profitability comparison with the four PJM-MISO plants that were subsidized under the ZEC scheme from 2017. Figure 6 shows that the nuclear plants were financially robust between 2017 and 2021 like their subsidized counterparts. More importantly, the empirical evidence suggests that the plants would remain viable without the new state CMC scheme or federal nuclear subsidies.

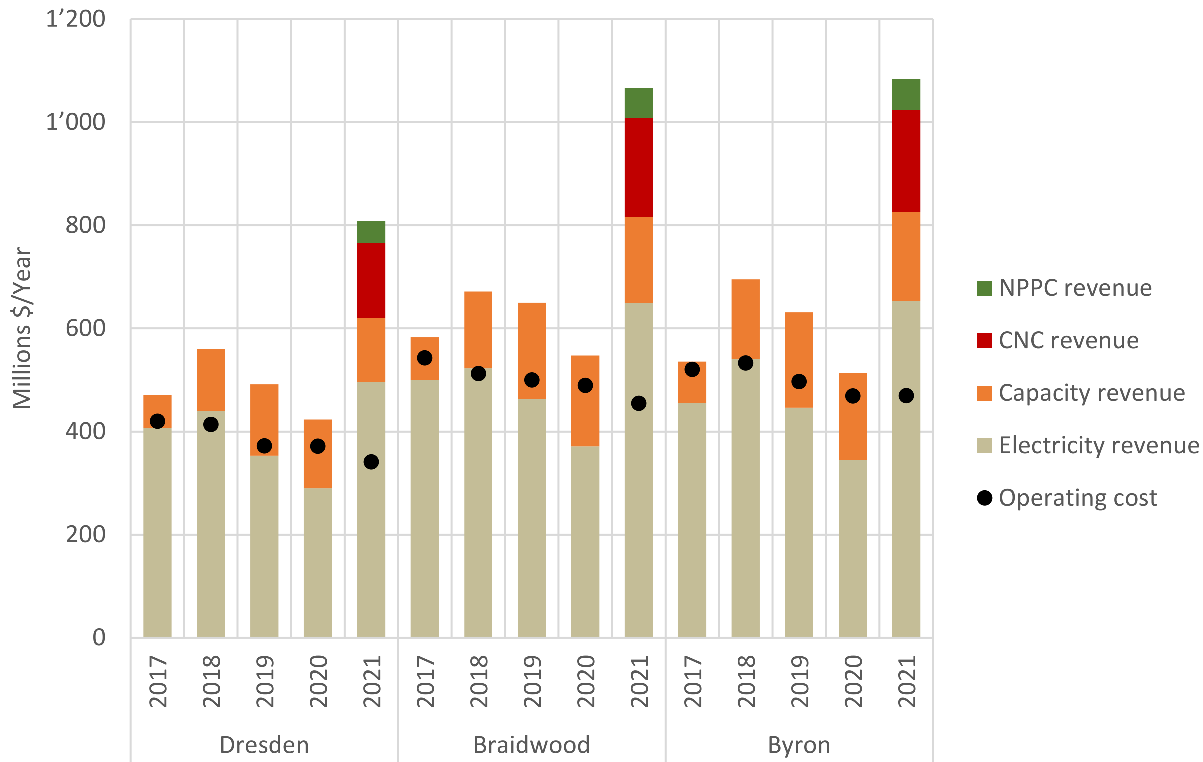

Figure 6. Profitability estimates of nuclear power plants in PJM subsidized under the CMC scheme.

4.3 Relative comparison between NYISO and PJM

To compare the relative profitability of nuclear units in both markets, the estimates in Figures 4 to 6 were converted into dollars per installed capacity (i.e., $/MW) and is depicted in Appendix B. For each respective market, the trends in the relative estimates reveal consistent profitability patterns across the NPPs. This is expected since the underlying data on operating costs, market prices and subsidy prices are uniform for each market. Comparing both markets, profitability patterns are consistent. Apart from 2019, NPPs were consistently profitable without the need for state support intervention.

5. Conclusion and policy implications

This paper reviews the financial performance of state subsidized NPPs across two dynamic markets and over a five-year period. The profitability analysis clearly establishes that 16 nuclear reactors are in an economically viable condition to continue operating without the need for any support schemes. Given the current and projected improvement in electricity market price conditions across the U.S., there is no economic justification for the introduction of federal support schemes. From a policy perspective, two policy implications can be drawn from the results. First, the coexistence of state and federal level support schemes and second, the dynamic nature of electricity markets.

As for the **coexistence of state and federal support schemes**, the findings in this study demonstrate that if state subsidized nuclear plants are allowed to obtain federal support funding, the magnitude of excess profits will be substantial. Therefore, the eligibility criteria for federal support schemes needs to be strengthened to negate an excess profit scenario and to ensure efficient allocation of federal resources. In particular, federal support schemes should disqualify nuclear plants already subsidized at the state level from applying for federal funding. The CNC scheme for example, does not specifically prohibit state subsidized nuclear plants from applying for the second award cycle[21]. Instead, applicants are required to disclose all revenues streams including payments from state programs when applying among other elements (DOE 2022c). Similarly, the NPPC factors in receipts from any state ZEC scheme when calculating the credit reduction amount. This signifies that state subsidized nuclear plants may potentially receive federal funding, albeit with reduced value.

Furthermore, rate-regulated nuclear plants should be disqualified from applying for federal funding, since regulators set customer rate charges that are sufficient to cover operating costs with an adequate return on investment (Holt and Brown 2022). Continuing with the CNC scheme, in the first draft guidelines published in April 2022, the DOE maintained that an applicant which "*recovers more than 50 percent of the nuclear reactor's cost position from cost-of-service regulation or regulated contracts will not be deemed to compete in a competitive electricity market*" and hence not eligible for the scheme (DOE 2022d, 11). In June 2022, the DOE revised the guidelines and repealed the 50% rule. Rather, nuclear plant owners can now demonstrate the nuclear plant participates in a competitive market by showing that a "*material amount of its total revenue*" would be derived from electricity markets (DOE 2022e, 11). This revision allowed the

[21] The draft guidance for the second award cycle was published on the 30th of September 2022. The funding coverage will commence in 2025.

owners[22] of the rate-regulated nuclear plant, Diablo Canyon to obtain federal funding of approximately $1.1 billion as elaborated earlier. Clearly, the CNC threshold for participation in electricity markets should be reinstated and revised upwards to avoid subsidizing nuclear plants that are not in dire need of financial support.

At the state level, state regulators should include or activate clauses that automatically rescinds state support once nuclear power plants are selected for federal level schemes. By strengthening eligibility criteria at both federal and state levels, tax-payer resources would only be extended to vulnerable NPPs that are unable to cover their operating costs from market revenues alone and face the risk of a premature retirement.

Electricity markets are dynamic in nature; therefore, state subsidy credit prices should be regularly reviewed to ensure it reflects current market conditions, and crucially, nuclear plant operating costs. In this dimension, the typical approach of state regulators is to set a threshold market price level, which reduces the credit value once market price exceeds the threshold. However, there are discrepancies in the implementation of the mechanism. For example, although the New York ZEC scheme includes a market price threshold, the threshold is fixed for the entire duration of the program and is not revised to reflect changing market conditions or nuclear plants financial conditions (Public Service Commission 2016). The New Jersey ZEC scheme provides nuclear plants a fixed ZEC price but does not incorporate a threshold mechanism (Monitoring Analytics 2019). A relatively simple solution would be imposing a flexible threshold that is regularly adjusted to match market dynamics. ZEC payments are then activated when market price declines below the threshold level and deactivated once market price hit or exceed the upper bound threshold. Implementing a more dynamic state subsidy scheme would also account for the effects of an expansion of renewable capacity in the electricity system. For example, as more renewables are integrated into the market and wholesale market prices decline[23] below a certain threshold level, the state support scheme is activated providing NPPs a financial buffer.

On a final note, the collective body of evidence suggests that there is a distinct policy agenda driving the nuclear support schemes. A possible explanation for this is that the present administration intends to spur investment in nuclear power, which necessitates stronger signals than simply ensuring nuclear power plant licensees break-even. A lucrative federal support scheme such as the Civil Nuclear Credit would provide significant incentives expand investments into nuclear power.

[22] The owner of the Diablo Canyon plant (PG&E) recovers all the plants operating costs through customer rate charges approved by the California Public Utilities Commission (Judson 2022).
[23] See (Olsina et al. 2007; Gelabert, Labandeira, and Linares 2011; Mills et al. 2021) for empirical evidence supporting this position.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

The data set used to generate the results will be made available upon request.

Appendix

Appendix A: Average nuclear power plant operating costs

Table A: Nuclear power plant average operating costs ($/MWh)

Year	Fuel	Operations	Total operating costs
2017	6.76	20.43	27.19
2018	6.47	20.12	26.59
2019	6.15	18.55	24.7
2020	5.76	18.27	24.03
2021	5.55	18.07	23.62

Source: (NEI 2017; 2020; 2021; 2022)

Appendix B: Relative profitability estimates for nuclear power plants

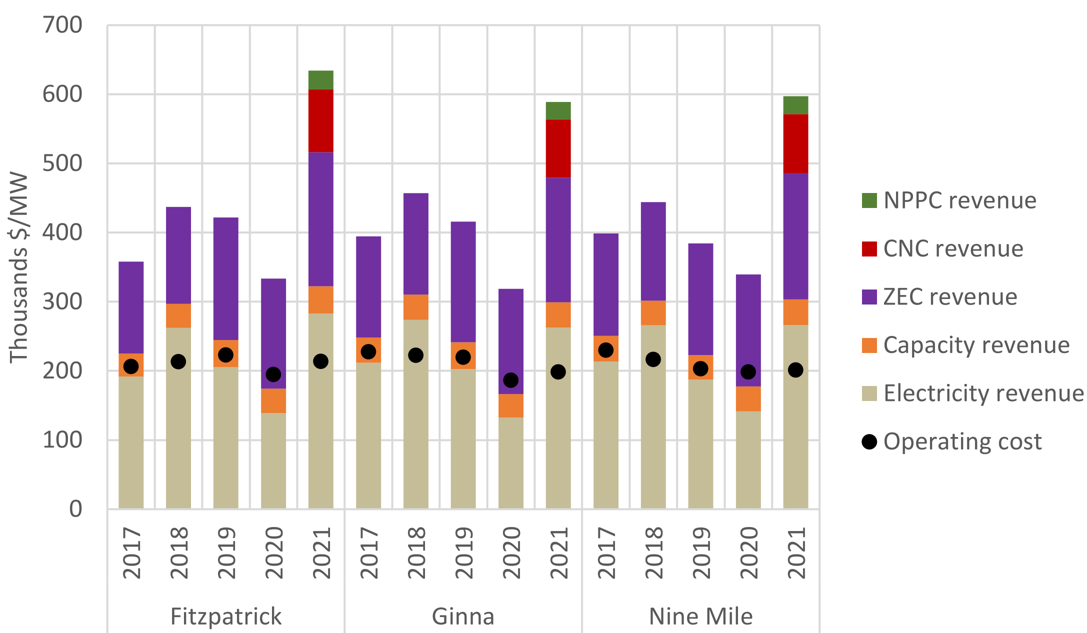

Figure B1. Relative profitability estimates of nuclear power plants in NYISO.
Note: The relative estimates were calculated based on the total installed capacity of the respective NPP.

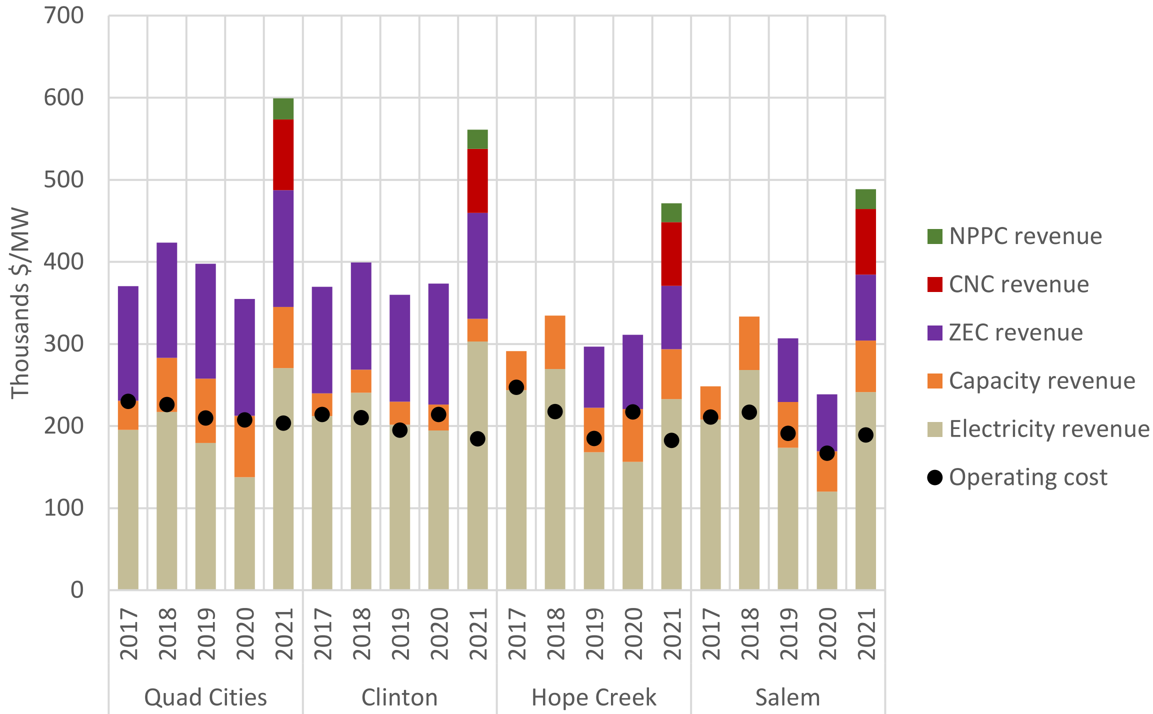

Figure B2. Relative profitability estimates of nuclear power plants in PJM

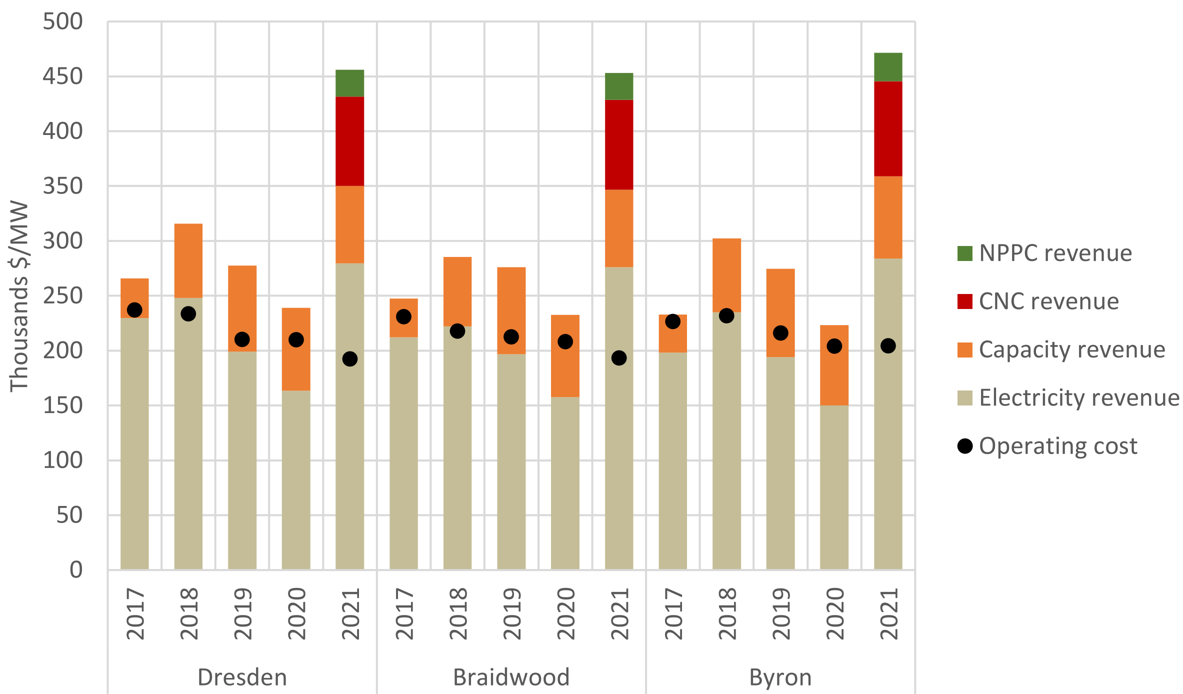

Figure B3. Relative profitability estimates of nuclear power plants in PJM subsidized under the CMC scheme

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