Impacts of Electricity Generation Regulatory Structures on Connecticut Ratepayers

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EXECUTIVE SUMMARY

Connecticut's electricity supply is restructured, which means that regulated utilities generally do not own power generation resources. In response to higher and more volatile electricity supply pricing in Connecticut, some stakeholders have suggested moving back toward a vertically integrated utility regulatory framework in which utilities would once again own at least some generation resources. Some of the primary objectives of re-regulation would be (1) lowering average cost by paying average cost of production rather than marginal cost and by accessing lower cost of capital, (2) improving price stability by using utility ownership of generation as physical hedges against market price volatility, and (3) increasing state policy influence on the resource mix. In this report, we identify three corresponding metrics by which to evaluate whether re-regulating electricity generation would benefit Connecticut consumers: average cost, price stability, and state policy considerations. Determining the impact of re-regulating electricity generation in Connecticut is complex, and some factors tend to lead to improved outcomes with re-regulation while others lead to worse outcomes (according to our three metrics). On the other hand, re-regulation would risk increasing costs by (a) reducing construction and operation efficiencies and (b) requiring utilities to purchase expensive generation assets currently held by other companies. Another consideration is that more modest reforms (such as changes to standard service procurement and allowing utilities to sign power purchase agreements, or PPAs) could achieve many of the same benefits as proponents of re-regulation seek to achieve. In this report, we evaluate these regulatory frameworks to determine how each would impact Connecticut consumers.

1. INTRODUCTION

The regulatory structure of the electricity industry impacts consumer costs and Connecticut's clean energy goals. In recent years, in the face of rising electricity prices and the need to transition to a clean electricity mix, stakeholders in Connecticut have raised questions about whether the state should move back toward a regulated electricity generation framework. Within such a framework, the state's regulated electricity distribution utilities would again be permitted to own and operate power plants. The Connecticut Office of Consumer Counsel (OCC) is charged with advocating on behalf of ratepayers and retained Synapse to investigate the impacts of the structure of the electricity generation industry on Connecticut ratepayers.

This report examines the tradeoffs associated with different regulatory frameworks for the electricity generation industry as they pertain to Connecticut. We first discuss the appropriate metrics for evaluating regulatory frameworks. Then we outline the benefits and costs associated with deregulation compared to vertical integration. Finally, we consider possible paths forward for Connecticut.

2. THE HISTORY OF RESTRUCTURING IN CONNECTICUT

Rate of return regulation (RORR) originated around 1910 to enable investor-owned utilities to access low-cost capital to build up the nation's electricity system. In exchange for monopoly control over a fixed service territory, utilities agreed to abide by regulations set by public utility commissions. This agreement is often referred to as the "regulatory compact." Utilities were allowed to recover prudently incurred costs via customer electric bills, with rates set by regulators. Under this regulatory framework, vertically integrated utilities handled electricity generation, transmission, local distribution, and customer billing. It allowed utilities to invest billions of dollars in electricity infrastructure across the country, leading the real price of electricity in 1970 to decrease to less than 2.5 percent of the cost Thomas Edison charged in 1892.[1]

Between 1970 and 1975, the price of electricity rose by 50 percent as the costs of oil, coal, and natural gas rose. This led to public dissatisfaction with the electricity industry. Around the same time, utilities were facing increasing difficulty building new generation on budget, particularly for nuclear generation. In New Hampshire, for example, the construction cost of Seabrook Station nuclear power plant cost rose from under $1 billion for both of the originally planned generating units in 1972 to $2.1 billion by 1988,

[1] Lave, L. Apt, J. and Blumsack, S. 2007. "Deregulation/Restructuring Part 1: Re-regulation Will Not Fix the Problems." Available at: https://www.cmu.edu/ceic/assets/docs/publications/working-papers/ceic-07-07.pdf.

despite the second unit being canceled, and resulted in the bankruptcy of the utility that built it.[2] Similarly, in Connecticut, Millstone Unit 3[3] was planned to cost $400 million in 1971, but the cost rose to more than $3.8 billion by 1984. The project led Northeast Utilities to request a rate increase of 27 percent.[4] Some of these challenges were caused by external factors, such as increasingly stringent rules from the Nuclear Regulatory Commission after the Three Mile Island accident. But the price increases also highlighted systemic issues with RORR that had previously been obscured by rapidly improving generation technology, and correspondingly lower electricity costs. These issues included overinvestment in capacity due to the allowed return on investment, challenges with growing technical and regulatory complexity, and inefficient operational procedures resulting from the ability to pass operating costs to customers. As these issues became clearer, Congress passed the *Public Utility Regulatory Policies Act of 1978* (PURPA) to encourage generation competition, renewable resources, and energy efficiency.[5] PURPA eliminated protected monopolies for electric generation and allowed non-utility generators to enter the market for the first time. Under PURPA, utilities must compensate independent power producers at an avoided cost rate set by the states. The Federal Energy Regulatory Commission (FERC) also encouraged wholesale competition through Orders 888 and 889, which required utilities to provide open access to their transmission facilities and open information regarding the transmission system.

Several states took this opportunity to restructure their regulatory frameworks for the electric generation sector in the 1990s. The process of "electricity restructuring" involved legal changes that enabled: (1) non-utility generators to sell electricity to utilities and (2) retail service providers to buy electricity from generators and sell to end-use customers. In restructured states, utilities were required to unbundle their generation assets from the rest of their service and put those assets up for auction.

Connecticut rode this wave of restructuring and passed Public Act 98-28 (P.A. 98-28) in 1998. The act required the state's electricity companies, along with the Department of Public Utility Control (DPUC), to initiate the creation of a competitive electricity market. The state's two electricity utilities, United Illuminating (UI) and Connecticut Light & Power (CL&P, now Eversource), were required to auction off ownership interests in non-nuclear generation facilities by January 1, 2000, and nuclear facilities by January 1, 2004.[6] CL&P sold its generation assets to Select Energy, an affiliated company. UI decided to leave the generation business entirely. The utilities sold all plants at prices higher than their book values

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[2] New York Times. March 2, 1990. "Chronology of Seabrook: Plans, Protests, Building." Available at: https://www.nytimes.com/1990/03/02/us/chronology-of-seabrook-plans-protests-building.html.

[3] Millstone is a 2,198 MW nuclear plant with two currently active generating units located in New London County, Connecticut.

[4] New York Times. November 10, 1985. "Tests Enter Homestretch for Millstone Unit 3." Available at: https://www.nytimes.com/1985/11/10/nyregion/tests-enter-homestretch-for-millstone-3.html.

[5] Union of Concerned Scientist. 2002. "Public Utility Regulatory Policy Act (PURPA)." Available at: https://www.ucsusa.org/resources/public-utility-regulatory-policy-act.

[6] McCarthy, K. 2002. "Electric Deregulation Timetable," prepared for the Connecticut Office of Legislative Research. Available at: https://www.cga.ct.gov/2002/olrdata/et/rpt/2002-R-0541.htm.

and used the excess to reduce the utilities' stranded costs.[7] P.A. 98-28 also allowed the utilities to recover generation-related stranded costs. Initially in 1999, the DPUC determined that CL&P could recover $3.6 billion and that UI could recover $801 million.[8] The auction of Millstone to Dominion in 2003 resulted in net proceeds of $415.3 million for CL&P and $15.7 million for UI to be applied to decrease stranded nuclear asset costs.[9]

In addition, the act required the utilities to provide standard offer service from January 1, 2000, until December 31, 2003, at a rate at least 10 percent below the rates charged by the companies on December 31, 1996. From January 1, 2004, onward, the utilities would still be required to provide default service to customers who did not choose a supplier, but there would be no price cap in place.[10] Instead of producing the electricity themselves as they had previously done, the utilities would now need to purchase it from independent generators on the market.

Around the same time, in 1997, ISO New England (ISO-NE) was created to serve as the New England region's Independent System Operator (ISO). ISO-NE launched its first wholesale electricity market in 1999 and eventually added related markets for services including regulation and capacity. The ISO-NE markets created a platform for independent companies to buy and sell electricity. Of the six New England states, all but Vermont chose to deregulate their electricity markets as well. In Vermont, deregulation was considered and even recommended by the Vermont Public Service Board, but ultimately was unable to achieve support in the legislature.[11]

Electricity prices in Connecticut rose in the period after the mandatory price cap ended, but it is challenging to separate out the impact of restructuring relative to other factors that impact electricity prices. New England has long experienced higher natural gas prices than the rest of the country due, in part, to constrained interstate gas pipeline infrastructure. With so much of the region's power coming from natural-gas-fired power plants, wholesale power prices are highly correlated to natural gas prices, making the region uniquely vulnerable to wholesale power price volatility associated with the costs of imported natural gas. This relationship has made it more difficult to isolate the impact of deregulation relative to the impact of higher natural gas prices. Recently though, rates have reached their highest levels in more than eight years. In January 2023, Eversource's (formerly CL&P) and UI's rates increased by more than 40 percent relative to rates at the end of 2022, resulting in residential monthly bills

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[7] McCarthy, K. 2002. "Electric Deregulation Timetable," prepared for the Connecticut Office of Legislative Research. Available at: https://www.cga.ct.gov/2002/olrdata/et/rpt/2002-R-0541.htm.

[8] McCarthy, K. 2002. "Electric Deregulation Timetable," prepared for the Connecticut Office of Legislative Research. Available at: https://www.cga.ct.gov/2002/olrdata/et/rpt/2002-R-0541.htm.

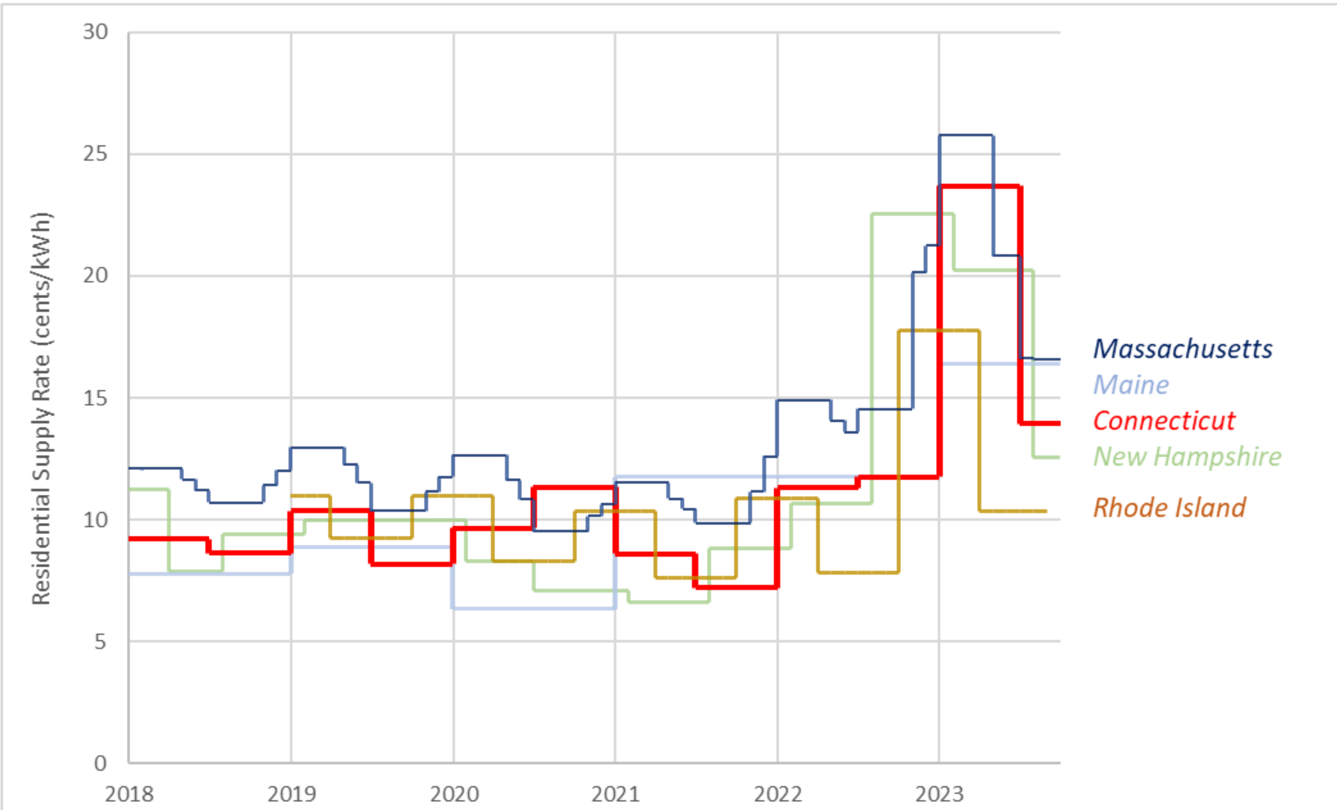
[9] Department of Public Utility Control. January 13 2003. "Draft Decision in the Application of the Connecticut Light and Power Company and the United Illuminating Company for Approval of their Millstone Nuclear Generation Assets Divestiture Plan – Disposition of Proceeds," filed in Docket No. 99-09-12RE02.

[10] McCarthy, K. 2002. "Electric Deregulation Timetable," prepared for the Connecticut Office of Legislative Research. Available at: https://www.cga.ct.gov/2002/olrdata/et/rpt/2002-R-0541.htm.

[11] Electric Restructuring in New England – A Look Back. December 2015. Reishus Consulting for NESCOE. Available at: https://nescoe.com/wp-content/uploads/2015/12/RestructuringHistory_December2015.pdf.

increasing by an average of $70–80.[12] Rates typically increase in the winter due to seasonally higher natural gas prices, but the increase this year was much larger than in the past. In large part, these recent rate increases are related to the hefty increases in natural gas prices caused by Russia's invasion of Ukraine. The spiraling electricity costs shined a spotlight on the unintended consequences of deregulation and triggered debates over how current market structures in Connecticut and the region may be contributing to these costs.[13] Figure 1 shows default residential supply rates between 2018 and 2023 for each of the five restructured New England states.

Figure 1. New England standard offer residential rates



Sources by state: Average of National Grid, Eversource East, Eversource West, and Unitil fixed residential basic service rates (Massachusetts); Eversource residential standard offer rates (New Hampshire); load-weighted average of Central Maine Power, Versant Power Maine Public District, and Versant Power Bangor Hydro District standard offer rates (Maine); Rhode Island Energy/National Grid Last Resort Service rates (Rhode Island); and customer-weighted average of Eversource and United Illuminating standard service rates (Connecticut).

[12] Crowley, B. 2022. "Eversource to Hike Residential Electric Bills 48%, United Illuminating 43%." *CT Examiner.* Available at: https://ctexaminer.com/2022/11/17/eversource-asks-to-hike-residential-electric-bills-48-united-illuminating-asks-43/.

[13] Crowley, B. 2022. *"*As Energy Prices Soar, Avangrid Places Blame on Companies Generating the Electricity." *CT Examiner.* Available at: https://ctexaminer.com/2022/12/02/as-energy-prices-soar-avangrid-places-blame-on-companies-generating-the-electricity/.

3. METRICS FOR EVALUATION OF ELECTRIC SYSTEM REGULATORY FRAMEWORKS

In this section, we identify metrics that can be used to evaluate the merits of alternative regulatory frameworks in the electricity industry.

3.1. Average Ratepayer Costs

Providing low-cost electricity to retail customers is one of the fundamental goals of an electric system. It was also a key argument in favor of restructuring, due to the idea that restructuring would enable more competition and increase electric system efficiency and innovation. As a result, average cost is arguably the most important metric for comparing electricity regulatory structures.

The primary drivers of final ratepayer costs are different between restructured and regulated electricity markets. In a deregulated market, prices are set by the marginal cost of production (at least in the absence of generator market power, as discussed later). In a regulated market, prices are set by the average cost of production (including a return on investment). The relative magnitude of marginal costs versus average costs has fluctuated over time. In addition, restructured and regulated markets rely on different mechanisms to keep prices reasonable. Restructured markets have competition that can drive more efficient development and operation of generation resources. Meanwhile, regulated markets rely on regulators to set effective rules and make decisions that require utilities to keep costs down.

It is worth noting that many other factors impact electricity costs beyond regulatory frameworks. These include exogenous, economy-wide factors that influence both marginal and average costs. Marginal costs are closely correlated with the price of the marginal fuel (usually natural gas). Average costs are significantly impacted by technology innovations occurring outside of the energy sector that can drive down capital costs. For example, gas turbine manufacturers adapted advances in airplane engines to improve gas turbines, and semiconductor improvements led to more efficient solar panels.[14]

These exogenous trends, notably the price of natural gas and technological innovations, generally dominate fluctuations in energy prices relative to any regulatory reforms—regardless of the regulatory framework.[15] Nevertheless, the incremental benefits of an efficient regulatory framework should not be neglected. A recent, comprehensive study compared energy prices between regulated and deregulated states, while controlling for other factors such as location, marginal fuel, and utility size.[16] The study

[14] Borenstein, S. and Bushnell, J. 2015. "The U.S. Electricity Industry After 20 Years of Restructuring."

[15] Borenstein, S. and Bushnell, J. 2015. "The U.S. Electricity Industry After 20 Years of Restructuring."

[16] MacKay, A. and Mercadal, I. 2022. "Deregulation, Market Power, and Prices: Evidence from the Electricity Sector." Harvard Business School Working Paper, No. 21-095, February 2021. (Revised December 2022.) Available at: https://www.hbs.edu/faculty/Pages/item.aspx?num=59929.

found that average retail electricity prices for customers in deregulated states increased relative to average retail prices in regulated states from 2000 to 2016 (the entire study horizon), following the phase-out of the transitional energy price caps. From 2006 to 2011, there was an average difference of $12.60 per MWh (which corresponded to a 16 percent increase) between energy prices in deregulated and regulated states, after accounting for the factors listed above. Despite fuel costs declining by an average of $6.90 per MWh in deregulated states from 2000 to 2016, retail prices increased by $7.90 per MWh over the same timeframe.[17] This phenomenon of negatively correlated fuel costs and retail energy prices implies that customers were seeing significant markups beyond the costs of production in deregulated states. Different regulatory frameworks saw differing outcomes in retail prices, despite the influence of exogenous factors.

3.2. Price Stability

An electric system regulatory framework should also keep retail residential service cost volatility low. Residential electricity ratepayer consumption is relatively inelastic because most of the electricity that people use is for essential tasks and appliances. As a result, residential customers have limited flexibility to shift their consumption of electricity over long time scales. This means that electricity rates that change significantly from one year to the next are of little value for shifting electricity consumption to times when lower cost electricity is available. On the flip side, electricity rate volatility makes it more difficult for ratepayers to budget for their electricity bills, which most significantly impacts low- and moderate-income customers.

For utilities operating in vertically integrated systems, volatile fuel prices and uncertainty around environmental compliance costs can lead to fluctuations in energy prices. However, public utility commissions monitor rates closely through rate cases and generally prefer to avoid sudden rate increases.

Utilities operating in a deregulated market need to assemble a portfolio of contracts with energy suppliers to serve customers who select the standard service option (we highlight standard service here because about 80 percent of Connecticut’s residential customers get their electricity supply through standard service).[18] Managing these portfolios involves inherent tradeoffs between reducing energy costs and minimizing volatility. These tradeoffs can be visualized as a “risk spectrum,” as illustrated in Figure 2 below.

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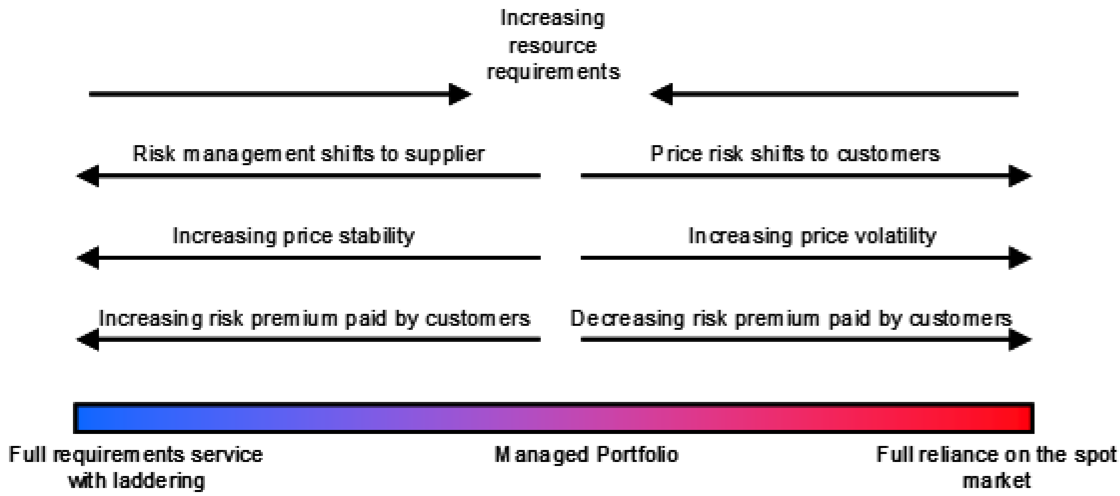
[17] Mackay and Mercadal, p. 20.

[18] Connecticut Public Utilities Regulatory Authority. May 19, 2023. “PURA Announces Electric Rate Adjustments to Take Effect July 1.” Available at: https://portal.ct.gov/PURA/Press-Releases/2023/PURA-Announces-Electric-Rate-Adjustments-to-Take-Effect-July-1.

Figure 2. Risk spectrum for electricity supply procurement strategies



Source: State of Connecticut's Power Procurement Plan.

The position of a portfolio along the risk spectrum is a function of the degree to which the portfolio relies on full requirements contracts versus the spot market. A fully hedged portfolio that consists entirely of supply contracts will have the greatest retail price stability, but the cost premiums will also be highest since all risk is transferred to the supplier. A portfolio that relies entirely on the spot market might result in the lowest cost to customers in the long run, but rates will be highly variable. The costs of hedging a portfolio, including risk management, credit support, and administrative costs, can vary according to the supplier's creditworthiness. The cost of hedging a forward contract also increases with the duration between the bid day and the start of delivery. In 2012, for example, the average aggregate cost of risk management, credit support, and administrative costs for Connecticut's portfolio made up roughly 8 percent of the total cost of full requirements service, but it has varied over time.[19] As of 2023, Eversource estimates that the wholesale supplier risk premium is more than 20 percent of the total supply cost, demonstrating how significant risk premium can be in determining overall cost.[20]

[19] Gaudiosi, J. and Levitan & Associates, Inc. 2012. "State of Connecticut's Power Procurement Plan." Filed in Docket No. 12-06-02. Available at: https://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/42b1ec7701eae8018525829c0074e85b?OpenDocument.

[20] Shuckerow, J. and P. Rogan. 2023. "Technical Meeting No. 6 Presentation: Alternative Standard Service Procurement Constructs." Available at: https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/71570d2e74f2e9f285258a27006dc204/$FILE/Eversource%20Presentation%2009.11.2023%20(Doc.%2017-12-03RE10).pdf.

3.3. State Policy and Regulatory Considerations

Policymaker influence on the resource mix

The electricity industry is a significant contributor to greenhouse gas emissions that cause climate change, and as a result Connecticut (along with other states and the federal government) has implemented policies to reduce these emissions. To accomplish that task, the generation mix will have to change dramatically in Connecticut and the other New England states. It is important for electricity regulatory frameworks to facilitate the clean energy transition. This can be achieved in a variety of ways. One potential advantage of vertical integration is direct oversight of the generation resource mix by state regulators. Through oversight of a regulated utility's planning procedures, regulators and policymakers can directly influence the generation resources that the utility uses to serve its load. Even without full vertical integration, allowing utilities to sign contracts with specific generation resources can help meet state goals to reduce emissions and jump-start new clean energy industries.

Regulatory complexity

Another policy and regulatory consideration for evaluating electricity generation market structure is the level of complexity and the amount of effort needed to adequately regulate the industry. In a vertically integrated market, regulators play a particularly essential role in keeping consumer costs down and in providing a check on poor utility decisions that could increase rates for customers. For this structure to succeed, regulators and stakeholders need to have resources, expertise, and independence so that they can understand utility operating practices and catch instances of poor or inefficient utility practice. In a restructured market, there is also a role for regulators to play, though the role is quite different. Regulators (in this case, federal regulators) must oversee market operators including ISO-NE to ensure that wholesale electricity prices are set fairly and to watch out for occurrences of participant market power.

4. Benefits and Risks of Deregulation

4.1. Production and Construction Cost Efficiency

Proponents of deregulation argued that a competitive energy market would lead to improvements in production cost efficiencies. With vertical integration, public utility commissions set rates based on the utility's cost of service and variable costs are passed directly through to customers. Reductions in variable costs only yield short-term, marginal profits until the next rate case, when rates are updated to reflect the lower cost of service. Utilities therefore have minimal incentives to decrease their operating costs.

In a restructured market, plants either sell energy on the spot market, or through long-term bilateral contracts (which are often based on expected spot prices). In the spot market, plants offer bids based on the price at which they are willing to generate electricity and are subsequently dispatched according to their bids. The lowest-cost plants will be dispatched first and most frequently. Since all plants are paid at a single clearing price, the lower-cost plants will see higher revenues relative to the more expensive plants, which are dispatched less frequently. As a result, plant owners are incentivized to reduce their operating costs so they can bid in at a lower price.[21]

In addition, restructured energy markets remove incentives for utilities to gold-plate new generation resources (i.e., spend more money than necessary in order to increase their profit). Independent power producers that recover their costs through competitive markets are incentivized to build their projects as efficiently as possible, because their revenues and return are independent of their investment. In a regulated market, this problematic incentive for gold-plating does exist, because utility returns depend directly on how much capital is put into the rate base. That can incentivize utilities to invest in capital improvements when alternatives (such as operational efficiencies) would be more cost-effective; this perverse incentive can risk utilities making and sticking with bad investments in costly resources given that they can recover their investment and earn a return as long as their regulator determined the resource was prudent.

4.2. Market Power and Rate of Return

The assumption of a competitive marketplace underlies the expected economic efficiencies associated with a deregulated market. However, deregulated wholesale energy markets, as they exist today, have several inherent features that undermine competition and lead to marked-up retail prices for consumers. Electricity is expensive to store for long durations and expensive to transport over long distances. Demand is relatively price inelastic, especially for residential customers as mentioned above. As a result of these two factors, generators supplying energy to a particular location at a particular point in time have a great deal of market power.

In theory, capacity shortages lead to higher prices and profits, which in turn attract investors. However, new resources entering wholesale markets face hefty barriers. The cost of new entry is high and requires substantial upfront capital. This capital, once invested, is effectively sunk into the new generator, as plants cannot be moved to a location where they are more needed. On the logistical side, construction has long lead times, transmission interconnection queues are lengthy, and interconnection costs can be unpredictable. In addition, uncertainty regarding fuel prices, environmental compliance costs, and evolving technology developments all expose investors to a high degree of risk. Investors need to trust that they will be able to recoup their investment over the lifetime of the project. When there is no guarantee that capacity markets will provide similar payment amounts over time, profitability is uncertain. Following deregulation, wholesale market seller concentrations tended to

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[21] Fabrizio et al. 2007. “Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency.” *The American Economic Review*.

remain high, but buyer concentrations fell.[22] Although utilities were forced to divest, they often transferred their entire generation portfolio to a single entity.

Uncompetitive markets allow generators to offer energy into the spot market at bids higher than their true marginal cost of production, although market participants are subject to market power mitigation rules intended to limit this opportunity. Since bilateral contracts reflect expectations around the spot market, this trend is generally seen in bilateral contracts as well. Gains in production cost efficiency can be offset by higher markups charged by generation companies, resulting in higher retail prices.

While market power is a significant concern in wholesale markets, it is less clear that the New England energy market has seen higher prices as a result. According to the ISO-NE Internal Market Monitor's (IMM) *2022 Annual Markets Report*, the four largest suppliers in New England provided 44 percent of on-peak generation and imports that year. The IMM also found that there was a pivotal supplier in approximately 25 percent of all five-minute intervals. However, the IMM estimated that suppliers did not mark up their marginal costs at all (on average, prices were 1.8 percent lower than they would have been if generators offered at marginal cost).[23]

One factor that has limited market power in New England is a robust transmission network. New England has the lowest level of transmission congestion in the nation. Between 2002 and 2021, ISO-NE coordinated the deployment of roughly $11.7 billion in bulk power system transmission investments, with another $1 billion scheduled to go into service between 2022 and 2025. Those bulk power system transmission investments are credited with lowering out-of-market costs and nearly eliminating transmission congestion costs.[24] In other grid regions, local import constraints can exacerbate market power challenges by increasing the importance of each individual generator inside of the transmission constraint. However, even though electricity flows easily within the region, New England is still relatively small in its entirety, and thus suppliers can have market power at the regional level.

There have been clear cases where market participants did exert market power in more notable ways. The Mystic Generating Station (Mystic) has market power due to its large size (~1,413 MW), location near large loads in Boston, and unusual access to imported liquified natural gas (LNG). When Mystic's operator attempted to retire the plant, ISO-NE instead signed a costly out-of-market contract that cost more than $520 million in its first full year (much of which was associated with Everett LNG terminal

[22] Mackay and Mercadal, p. 25.

[23] ISO New England Internal Market Monitor. 2023. *2022 Annual Markets Report*. Available at: https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf.

[24] Potomac Economics, *2022 Assessment of the ISO New England Electricity Markets* (June 2023), https://www.potomaceconomics.com/wp-content/uploads/2023/06/ISO-NE-2022-EMM-Report_Final.pdf. In its 2021 Assessment of the ISO NE markets, the external market monitor for ISO-NE, Potomac Economics, noted that ISO-NE had the lowest congestion rate in 2021 ($0.38/MWh) and 2022 ($0.37/MWh), 10 to 22 percent lower compared to average congestion levels in ERCOT, MISO, PJM, and NYISO, but also the highest transmission rate in 2021 and 2022 (nearly $22/MWh), reflecting higher investment in transmission upgrades compared to the other RTOs. Page 4.

congestion management costs). ISO-NE determined the contract was needed until transmission upgrades could be made to allow other generators to better serve Boston's loads.[25,26]

Market power is not limited to wholesale prices. There can also be market power and limited competition in electricity supply procurements that determine the electricity supply price for consumers who remain on standard service. These procurements can suffer from market power if there are relatively few bidders or if bidders face significant risks due to the structure of the procurement (such as risks associated with the duration of the contract or with uncertain future load levels).

4.3. Utility Ownership and Long-Term Contracts as Hedges

While the competitive nature of a well-functioning restructured market can help to keep costs close to the marginal cost of production, it is possible for the marginal cost of production to vary considerably over time, from day to day, season to season, and year to year. As described in Section 3, this price volatility can have undesirable impacts on consumers while providing limited benefit. One potential benefit of vertical integration of electric utilities is that they can own physical generation infrastructure that can be used to alleviate price shifts. In addition, both vertically integrated and restructured utilities can sign long-term contracts to similarly improve price stability. Owning some types of generation with lower and more stable operating and fuel costs, such as renewable energy, can reduce the need for utilities to purchase spot market energy that is often priced based on the more volatile marginal cost of fossil fuel power generation. Long-term contracts can allow utilities to lock in prices in advance and avoid the need to purchase spot market energy that is subject to short-term price volatility. While utilities can use long-term contracts in restructured markets to hedge against volatility, as utilities use long-term contracts to satisfy an increasing share of their customers' loads, competition can decline (since incumbent suppliers have contracts locked in).

4.4. State Influence in Resource Mix

Permitting utilities to own generation or sign long-term contracts can give states a mechanism for directly influencing the resource mix. Connecticut and other New England states have, for example, had their utilities sign long-term contracts with offshore wind generators because offshore wind is seen as essential for meeting state policy objectives such as greenhouse gas emissions reductions. Without these contracts, states would instead need to increase their reliance on more indirect policies such as renewable portfolio standards that generally require deployment of resources with certain attributes in the New England region to meet state clean energy goals.

[25] ISO-NE Internal Market Monitor*, 2022 Annual Markets Report* (June 5, 2023), https://www.iso-ne.com/static-assets/documents/2023/06/2022-annual-markets-report.pdf. Page 9.

[26] ISO New England. November 2023. "Mystic Cost of Service Preliminary Report." Available at: https://www.iso-ne.com/static-assets/documents/100005/mystic_cos_prelim_09_2023.pdf.

4.5. Regulatory Complexity and Capture

One challenge associated with vertical integration is that regulation requires significant resources and expertise to be successful in keeping rates reasonable and maintaining high quality utility service. The electric grid is a complex system both technologically and economically, and substantial technical expertise is important for effective system operation and planning. Even understanding the ISO New England wholesale markets can be a difficult task. This means that effective regulation requires resources and sufficient technical expertise to provide a thorough understanding of the technical issues at hand.

The complexity of utility regulation also creates opportunities for utilities to exert influence on system planning and operation in ways that enrich shareholders at the expense of customers. Utilities, as large, for-profit businesses, are structured to seek ways to increase earnings for shareholders. They also have expertise and sophistication with respect to their assets and are typically best positioned to understand the costs and other impacts associated with their decisions. While regulators can benefit from this information by requesting it from utilities, depending too much on utility technical support risks increasing utility influence in regulatory decision-making. In the worst cases, there can be even more direct utility influence on commission decisions. For example, sometimes commissioners end up working for industry when their term has ended, as company executives or lawyers.[27] Strong safeguards are critical to prevent conflicts of interest that could impact regulators' decisions.

These challenges are not insurmountable; they can be mitigated by increasing funding and independent technical support for regulatory agencies, and by setting limitations on how quickly staff can transition between regulatory and utility roles. Rather, these challenges demonstrate that effective utility regulation in the absence of a restructured market requires significant resources and safeguards.

5. POTENTIAL REGULATORY FRAMEWORKS FOR CONNECTICUT

5.1. Existing Connecticut Framework with Anticipated ISO Market Reforms

Connecticut currently has a restructured electricity market structure, in which the state's two utilities are generally not allowed to own generation assets. Customers can either source energy through UI's or Eversource's standard offers, or through third-party suppliers. Around 19.5 percent of UI customers and 23.3 percent of Eversource customers are currently opting for third-party suppliers.[28] These reflect moderately higher percentages than the past couple years due to the recent increases in supply rates.

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[27] Lave, L. Apt, J. and Blumsack, S. 2007. "Deregulation/Restructuring Part II: Where Do We Go From Here?" Available at: https://www.cmu.edu/ceic/assets/docs/publications/working-papers/ceic-07-07.pdf.

[28] Besthoff, L. 2023. "CT electric customers still switching to third-party suppliers." Available at: https://www.nbcconnecticut.com/investigations/ct-electric-customers-still-switching-to-third-party-suppliers/3061194/.

Looking back further in history, retail choice participation using third-party suppliers in Connecticut peaked at 42 percent in 2013.[29]

Third-party suppliers can sometimes provide lower rates through more sophisticated financing or procurement mechanisms. However, recent analysis of data from 2017 to 2021 showed that the majority of residential customers in Connecticut who signed up with third-party suppliers overpaid relative to the utilities' standard offers.[30] Low-income customers were disproportionately harmed. Massachusetts has seen a similar dynamic.[31] Guardrail requirements for third-party suppliers such as prohibiting exit fees and robust transparency rules are important to protect consumers from opaque or overpriced suppliers.

The utilities' standard offer procurement process follows the requirements outlined in the State of Connecticut's Power Procurement Plan for Standard Service.[32] UI procures all of its Standard Service load requirements from suppliers. Since CL&P had the administrative capacity to participate in market transactions, it was granted the option to serve as the load-serving entity and manage a portfolio of products for up to 20 percent of its Standard Service load in the initial procurement plan, though procurement managers may increase or decrease this limit.[33] CL&P recently exercised this option at the direction of the procurement manager when prices skyrocketed for standard service costs during the winter of 2023. Both utilities procure energy in laddered tranches, consisting of 10 percent of the given utility's standard service for 6 months. Figure 3 illustrates this laddered layout as implemented in UI's most recent RFP.[34] Entities are allowed to bid on multiple tranches (for example, a supplier could bid to supply 20 percent of load for 6 months, or 10 percent for 12 months). This structure is intended to offer enhanced flexibility to suppliers, while minimizing the amount of time between bid submission and the commencement of delivery.

[29] U.S. Energy Information Administration. 2023. "Residential retail electric choice participation rate has leveled off since 2019." Available at: https://www.eia.gov/todayinenergy/detail.php?id=55820.

[30] Connecticut Public Utilities Regulatory Authority. 2023. "Two-Year Review Required Pursuant To Conn. Gen. Stat. § 16-245O(M)," filed in Docket No. 18-06-02RE01. Available at: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a5 4110e3e852576190052b64d/85a82ac70f76ba90852589520054685b/$FILE/Investigative%20Report.pdf.

[31] Baldwin, S. and Howington, T. 2023. "Consumers Continue to Lose Big: the 2023 Update to An Analysis of the Individual Residential Electric Supply Market in Massachusetts." Prepared for the Massachusetts Attorney General's Office. Available at: https://www.mass.gov/doc/consumers-continue-to-lose-big-the-2023-update-to-an-analysis-of-the-individual-residential-electric-supply-market-in-massachusetts/download.

[32] Gaudiosi, J. and Levitan & Associates, Inc. 2012. "State of Connecticut's Power Procurement Plan." Filed in Docket No. 12-06-02. Available at: https://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/42b1ec7701 eae8018525829c0074e85b?OpenDocument.

[33] Gaudiosi, J. and Levitan & Associates, Inc. 2012. "State of Connecticut's Power Procurement Plan." Filed in Docket No. 12-06-02. Available at: https://www.dpuc.state.ct.us/dockhistpost2000.nsf/8e6fc37a54110e3e852576190052b64d/42b1ec7701 eae8018525829c0074e85b?OpenDocument.

[34] Term Sheet for UI Standard Offer Procurement.

Figure 3. United Illuminating's tranche structure

	2023	2024
Tranches	2nd Half	1st Half
10%		
10%	Future RFPs	
10%	Tranche 4	
10%	Tranche 3	Future RFPs
10%	Tranche 2	
10%	Tranche 1	
10%		
10%	40% Filled	Tranche 7
10%		Tranche 6
10%		Tranche 5
100%		

Source: 2023-04-21 UI Attachment 3 Exhibit A Term Sheet RFP 042023 #32-01-02.pdf, Available at: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/1d46088042a35ad8852589980050521e?OpenDocument.

In addition to Connecticut's procurement strategies, the current regulatory framework depends considerably on ISO-NE's markets. These markets are responsible under restructuring for attracting competition and facilitating market transactions. Without direct utility ownership and development of generation, the markets (alongside state policies) also determine resource mix outcomes. There are several market dynamics that could change in the future as a result of ongoing market reform efforts.

Two of those changes involve market design proposals ISO-NE is currently developing. The first, Resource Capacity Accreditation (RCA), is intended to improve signals in the capacity market for resources that are available when most needed. These include extended cold snaps when natural gas power plants might not be available. The second, the Day-Ahead Ancillary Services Initiative (DASI), was proposed to ensure enough resources are preparing to have fuel and generate if needed in the day-ahead market to avoid a shortage in real time (when it is too late to procure fuel/start up). ISO-NE has expressed that both market design reforms will be critical to more accurately compensate resources based on the value that they provide to the system, which in theory would result in a more optimal, cost-effective resource mix. In addition, ISO-NE is evaluating potential adoption of a prompt and/or seasonal capacity market to replace the annual, three-year forward capacity market that exists today. A prompt market would improve the accuracy of the quantity of capacity procured in the market by ISO-NE, while potentially better facilitating participation and competition from resources that can be constructed in less than three years and that might not have bid in three years in advance of operation. A seasonal market could improve the precision of both the amount of capacity procured by ISO-NE and the accreditation of each capacity resource by better aligning the market with seasonal system needs and resource performance.

While ISO-NE implements these market designs, the changing resource mix due to the competitiveness of relatively newer technologies including renewables and battery storage will also be impacting market prices. New entry from independent developers or smaller companies could potentially reduce ownership concentration in New England. Similarly, growing loads could increase the total number of generators and raise the bar for determining whether a single owner has a large enough portfolio of resources to exert meaningful market power.

5.2. Full Vertical Integration

In response to public dissatisfaction with high electricity rates, stakeholders in some states have proposed regulation reforms to mitigate market power concerns. The most extreme case of this would be a return to vertical integration. Under this approach, utilities would be permitted and expected to own generation resources to serve the majority of their load. Vertical integration could reduce short-term price volatility and could mitigate concerns about market power in competitive markets. However, a return to vertical integration would re-introduce the same challenges that led people to advocate for deregulation originally. These original issues, including reduced generation competition, regulatory capture, and capital overinvestment, would be difficult to fix.

In addition, the costs of reregulation would be high. To return to a vertically integrated system, utilities would need to purchase generation assets and put them into their rate base. Many generation assets auctioned off during restructuring were sold at below market prices, and utilities were then compensated for their losses by stranded asset charges. Some low-cost baseload plants were later resold at higher prices.[35] These low-cost plants are often highly profitable, and owners would claim a high present market value based on expected revenues. If generators were put into rate base at current market values, ratepayers would be locked into high electricity prices for the remaining lifetime of the assets. On the other hand, if the assets were valued at below-market values, this would potentially involve taking property without fair compensation, and would likely lead to extended litigation. In Section 5.5, we estimate the cost to the utilities of repurchasing the Millstone nuclear power plant.

5.3. Partial Vertical Integration

One intermediate option for reform that stakeholders have recently brought forward is allowing utilities to own significant clean energy assets. In Connecticut, this might include nuclear, offshore wind, and solar resources. Under this framework, utilities would avoid the legal and economic complexity of purchasing fossil plants, while still being able to take direct advantage of low-cost clean energy, without any potential price mark-ups due to generator market power or price volatility associated with

[35] Lave, L. Apt, J. and Blumsack, S. 2007. "Deregulation/Restructuring Part II: Where Do We Go From Here?" Available at: https://www.cmu.edu/ceic/assets/docs/publications/working-papers/ceic-07-07.pdf.

purchasing power on the spot market. We explore the potential costs associated with this option in Section 5.5 below.

Purchasing and owning Millstone, the sole nuclear power plant in Connecticut, would be a large upfront cost, but could potentially offer long-term returns as a source of reliable, dispatchable, baseload clean power. This net cost-benefit analysis would require a close examination of the expected purchase price, remaining lifetime, operating costs, and estimated market power currently exerted by Millstone. We include more discussion of these potential net costs versus savings in Section 5.5.

5.4. Revised Standard Service Procurement

Revising Connecticut's standard service procurement process could lead to lower prices for consumers. There are several potential levers for change policymakers could pull to mitigate market power among generators and promote a more competitive solicitation process. Options for consideration include:

1. *Allow utilities to hedge with renewable energy power purchase agreements.* Properly procured long-term contracts for renewable power can promote price stability and lower costs. Renewable developers do not rely on volatile fossil fuel prices and are not subject to unpredictable environmental regulations, so they are inclined to offer fixed-price contracts. Utilities could use PPAs to hedge against volatile New England wholesale prices.

2. *Redesign tranches.* The tranches under the current framework include requirements to serve 10 percent of each of the four customer classes. A more sophisticated tranche design could include different procurement schedules for different customer classes or break out the load by specific types, such as days/nights or weekends/holidays. This would provide competitive suppliers with more options that might better suit their generation profiles and costs.

3. *Innovate on auction mechanisms*. Different live auction mechanisms, such as descending clock auctions, can help create more transparency and lead to more competitive bidding processes. Competition would still be essential for producing low-cost procurements under alternative auction mechanisms.

4. *Community choice aggregation.* Allowing communities to test out additional approaches to manage their own energy supply can open opportunities for other energy supply procurement strategies. Community choice aggregation (CCA) can help communities take advantage of the benefits of competition while eliminating the need for residential customers to navigate the wholesale electricity industry on their own. Other states, including Massachusetts, have extensive experience with CCA programs. In Massachusetts, most CCAs have resulted in savings for customers, even while they have procured a greener electricity mix. An analysis from the Green Energy Consumers Alliance, which supports CCAs, found that the 41 municipalities that procured electricity mixes with 5–11 percent more renewable energy than required saved participants an average of 3.3 cents per kWh relative to basic service (the Massachusetts version of

Connecticut's standard service) between 2017 and 2023.[36] However, as the Public Utilities Regulatory Authority noted in its study of CCAs, it is important to limit load uncertainty associated with customers moving between standard service and CCAs. Load uncertainty in standard service procurements increases risk on suppliers bidding to serve standard service load and thus can lead to increased costs for customers remaining on standard service.[37]

5.5. Comparison of Costs

Each regulatory framework has a unique set of associated costs. Comparing the precise total system costs under each framework is difficult, given the significant uncertainty and complexity of the market interactions involved. However, the major cost categories' magnitudes can be estimated to understand the directional impacts that each type of regulatory framework would have.

Estimation of costs of acquiring generation assets

Under both the vertical and partial integration frameworks, utilities would need to acquire some amount of generation assets.

Under the partial integration framework, one of the utilities would be able to purchase Millstone, the only nuclear power plant in Connecticut. In 2001, Dominion Energy purchased the majority ownership of Millstone at a state-mandated auction for $1.28 billion. It purchased 100 percent ownership of Units 1 and 2 (though Unit 1 had been shut down, and Dominion simply took over the decommissioning responsibility) and 93.47 percent of Unit 3.[38] Accounting for inflation, this would be approximately $2.11 billion in real 2023 dollars. This historical purchase price is helpful as a reasonable benchmark datapoint for estimating what Millstone could sell for in the present. The current purchase price of Millstone might be slightly lower, given that the plant is now 22 years older. However, this downward price pressure could be offset by the fact that the selling party could have more bargaining power since the plant likely wouldn't be sold through a state-mandated auction. In addition, the buying party would not need to shoulder the expense of decommissioning Unit 1 as Dominion did.

At a high level, to evaluate whether the acquisition of Millstone would be an economically beneficial decision, we can consider a thought experiment where we hold the purchase price constant at this

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[36] Chretien, L. and M. Hondros-McCarthy. 2023. *Green Power at Lower Cost.* Green Energy Consumers Alliance. Available at: https://260434.fs1.hubspotusercontent-na1.net/hubfs/260434/GMA%20Report%202023%20-%20Final.pdf.

[37] Gillett, M., J. Betkoski III, and M. Caron. 2021. PURA Study of Community Choice Aggregation. Available at: https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/b3853f998a4dba83852587820067942b/$FILE/200513-110321.pdf.

[38] Yale School of Management. *The History of the Millstone Nuclear Power Plant.* Accessed November 15, 2023. Available at: https://workshop1.cases.som.yale.edu/future-nuclear-connecticut/millstone-plant/history.

historical datapoint and vary the marginal energy cost savings to calculate the payback period. For these calculations, we assume Millstone operates at the same average capacity factor it operated at from 2019 to 2021 (92.9 percent for Unit 2 and 89.8 percent for Unit 3)[39] for all future years. Given the high-level nature of this benchmarking calculation, we do not consider the time value of money, so these results represent the most conservative view one could take on payback period.

A recent study found the average retail price in restructured markets was $7.66/MWh higher relative to regulated markets from 2000–2016.[38] It is unclear how the average differential between restructured and regulated markets has changed over the last 7 years, so we tested a range of values around this finding. Table 1 shows the results of this thought experiment. If you assume the utility saves $1 per MWh of energy generated from Millstone by avoiding a presumed market power energy price markup, it would take 127 years to recover costs. On the other extreme end of the spectrum, if you assume the utility saves $8 per MWh of energy generated from Millstone, it would take 16 years to recover costs. These results provide a lower bound on the potential payback period, since they do not account for the cost of capital, and the corresponding time required to pay back that back. A decision around whether this is cost-effective would need to consider factors including the expected remaining lifetime of Millstone, the expected cost of capital, the estimated energy cost savings and any opportunity cost associated with the significant capital investment.

Table 1. Estimated payback period for purchasing Millstone, assuming a range of energy savings

Assumed Energy Cost Savings (2023$/MWh)	Payback Period (Years)
1	127
2	64
5	25
8	16
12	11

Estimation of costs of building new generation

Under both the vertical and partial integration frameworks, utilities would also build new renewable resources themselves rather than relying on merchant developers and generation owners. There are at least two factors that could impact the cost of utilities building new resources: cost of capital and technical expertise/construction efficiency.

39 Nuclear Energy Institute. July 2023. *U.S. Nuclear Operating Plant Basic Information.* Available at: https://www.nei.org/resources/statistics/us-nuclear-operating-plant-basic-information.

Cost of capital depends on the amount of risk that a company faces in developing a project. According to the U.S. Environmental Protection Agency's (EPA) power sector modeling framework, merchant generation owners face greater risks because their revenues depend largely on market prices and short-term hedges. In contrast, vertically integrated and regulated utilities are entitled to a return on any investment deemed prudent by regulators, which provides greater long-term revenue certainty. As a result, EPA assumes in its modeling that regulated utilities have a Weighted Average Cost of Capital (WACC) of 4.88 percent relative to a WACC of 6.65 percent for merchant owners.[40] Differences in cost of capital do significantly impact total cost to customers. For example, on a levelized basis, we calculate that a reduction in WACC of just 1.77 percent, equal to EPA's assumed difference between merchant and regulated utilities, can reduce the total cost of the project to consumers by approximately 12 percent.

However, EPA notes that generation developers and owners with long-term PPAs with regulated utilities can face notably less risk than those that rely more on spot market prices. EPA suggests that "[w]ith a guaranteed, longer-term price, the risk profile of this segment of the IPP fleet is similar enough to be treated as regulated plants." This finding has major implications for Connecticut, where new offshore wind resources are procured through long-term PPAs. If that approach continues, permitting regulated utility ownership of these resources may produce limited benefit associated with lowering the cost of capital. In this case, the savings associated with reducing the cost of capital could be much less than the 12 percent noted above. To estimate an order of magnitude impact, we assume that lower cost of capital through vertical integration would reduce costs by 6 percent, assuming that developers with PPAs have costs of capital between those of full merchant generators and regulated utilities.

A second factor that could differentiate costs of new renewable resources in a vertically integrated environment is how cost-effectively and efficiently the utility can build the new resources. On one hand, merchant developers might be incentivized to be more efficient with their spending, because any savings result in greater returns on their investments. For regulated utilities, returns depend on the amount the utility invests, and there is less incentive to be more efficient during construction. It is difficult to evaluate construction cost efficiency differences directly. As a proxy, we consider the marginal cost of production reduction associated with deregulation as identified by MacKay and Mercadal, who find a nearly 15 percent reduction. Complicating construction efficiencies is the technical expertise that each company has in building large, complicated projects such as new offshore wind generation facilities. In-house expertise can vary between each company, whether regulated or merchant, and can contribute to how efficiently the company can build the project and how likely the project is to stay within budget.

Finally, there are additional factors that we do not quantify here. One is that a project built through a PPA has relatively more cost certainty relative to a utility-built project that permits the utility to recover all the costs it ultimately incurs in building the project. On the flip side, there may be higher risk of

[40] U.S. Environmental Protection Agency. 2023. "Documentation for Post-IRA 2022 Reference Case: Chapter 10." Available at: https://www.epa.gov/system/files/documents/2023-03/Chapter%2010%20-%20Financial%20Assumptions.pdf.

merchant projects not being completed due to changing conditions and cost increases that reduce the viability of the project. Recently, inflationary impacts have led to offshore wind project cancellations in Connecticut and other states up and down the east coast.[41] In addition, the treatment of tax credits can be different between vertically integrated and restructured generation resources. Vertically integrated utilities may be required to normalize the tax credit benefits across a project's lifetime, which can decrease their value.

The table below compares each of the scenarios described above using the metrics identified in Section 3.

Table 2. Comparison of vertically integrated regulatory frameworks relative to restructured status quo by metric

Metric	Restructured	Vertically Integrated
Average ratepayer cost	Efficient construction and operation achieve up to 15 percent savings for generators. Ratepayer savings may not be as high due to generator mark-ups.	Reduced cost of capital could lower total cost of new offshore wind on the order of 6 percent. Acquiring Millstone could cost on the order of $2 billion.
Price stability	Reliance on wholesale market prices can increase volatility, though long-term PPAs or hedges can mitigate this effect.	Reduced dependence on wholesale market prices can reduce volatility, though fuel inputs could still result in volatility if the utility owns fossil-fuel-powered generators.
State policy considerations	State can require utilities to sign PPAs with desired existing and new resources to impact the resource mix.	State can exert direct control over the resource mix through approval of utility resource builds and retirements.

6. Discussion and Conclusions

Both vertical integration of utilities and market procurement of electric power involve numerous complexities and risks that can impact consumers. We do not find clear justification from our analysis for re-regulating electric generation in Connecticut by allowing utilities to once again own generation resources. It is not clear from our analysis that utility ownership of generation resources is necessary to improve outcomes in any of the three metrics we identify: average cost, price stability, and state policy

[41] Penrod, Emma. October 4, 2023. "Avangrid moves to cancel Park City offshore wind contracts on heels of SouthCoast termination." *Utility Dive*. Available at: https://www.utilitydive.com/news/avangrid-cancel-park-city-offshore-wind-contracts-southcoast-shell/695552/.

implications. Any changes to electric generation regulation should be clearly targeted to an identified problem, such as elevated or volatile electricity prices. But for each metric identified in this report, there are lower risk alternatives to utility ownership of generation that could achieve similar benefits. These include long-term contracts and PPAs to improve price stability and increase state policy influence on the resource mix, and standard service reforms (such as allowing community choice aggregation) that could increase competition in supply procurements to reduce average costs. Meanwhile, utility ownership of generation resources risks (1) incurring significant costs to purchase existing resources such as the Millstone nuclear power plant and (2) reducing construction and operational efficiencies that result from the restructured, competitive market.

While moving back toward a vertically integrated electricity system could address some concerns about restructured markets, regulating electricity generation would bring back its own challenges. There would also be considerable obstacles associated with the transition between today's restructured framework and a future vertically integrated one. Intermediate steps that do not require full vertical integration may offer more promise. These include some steps that Connecticut has already taken, such as authorizing or requiring regulated distribution utilities to sign long-term contracts with specific generation resources, such as Millstone. Long-term contracts can help reduce price volatility and increase state input into the resource mix, though they risk creating opportunities for specific resources with desired attributes to exert market power at ratepayer expense. In the case of Millstone, the utilities signed a 10-year contract to purchase half the plant's output at $49.99/MWh, which increased costs in 2020 but led to savings for consumers in 2022.[42]

A key challenge facing restructured electricity markets throughout North America is the threat of market power. While restructuring has been found to improve operational efficiency of the electricity generation system, market power risks offsetting those gains. For restructured electricity markets to succeed in delivering low-cost electricity to customers, it is critical that these markets are transparent and competitive across all of their components—from the ownership concentration of generators to the suppliers competing to provide retail electricity supply to ratepayers. Today, the exercise of market power is generally limited in ISO-NE's wholesale electricity markets, but market power and risk premiums in supply procurements can increase retail supply costs above spot wholesale prices.

Re-regulation of the electricity generation industry in Connecticut is not a simple or clear fix and it would carry significant risks to consumers. However, there are opportunities to implement more forward-looking improvements to the existing restructured regulatory framework that are more targeted to the challenges the state and region currently face.

[42] Crowley, Brendan. August 29, 2022. "Controversial Millstone Guarantees Pay Dividends for Customers with Drop in Electric Rates." *Connecticut Examiner*. Available at: https://ctexaminer.com/2022/08/29/controversial-millstone-guarantees-pay-dividends-for-customers-with-drop-in-electric-rates/.