STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

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	)	
Public Service Company of New Hampshire d/b/a Eversource	)	**Docket DE 24-046**
2024 Default Service Solicitations	)	
	)	

Direct Testimony of

Marc Vatter

Director of Economics and Finance
Office of the Consumer Advocate

September 11, 2024

Q. Please state your name, position, and business address.

A. My name is Marc Vatter. I am Director of Economics and Finance for the New Hampshire Office of the Consumer Advocate (OCA).

Q. How long have you worked for the OCA?

A. I have been employed at the OCA since August 25th of last year.

Q. Is a summary of your experience attached to this testimony?

A. Yes. Attachment MV-1 is my resume.

Q. Have you previously testified before utility regulatory commissions?

A. Yes. I have testified before the New Hampshire Public Utilities Commission, as well as the FERC, the Energy Facilities Siting Board of the Rhode Island PUC, the Michigan PSC, and the Mississippi PSC.

Q. What is the purpose of your testimony in this docket?

A. At the direction of the Commission, Eversource has proposed a default energy service procurement plan that involves increasing reliance on the spot market as opposed to the six-month all-requirements contracts that had been the norm until recently. My testimony proposes an alternative to this approach: reliance on a different market – the futures market – as the best way to harness competitive forces in a manner calculated to make electricity as attractive as possible for the utility's residential customers.

Q. **What is your understanding of Eversource's proposal and the reasons for it?**

A. On December 21, 2023, via Order No. 26,920, the Commission ordered Eversource to change its default energy service procurement protocol from one entirely reliant on solicitations for six months of all-requirements service to one in which up to 20 percent of the load would be served via energy procured through the ISO-New England day-ahead or real-time markets (which I refer to collectively here as the "spot market"). The utility did as it was directed. Next, in Order No. 26,994, entered on April 12, 2024, the Commission approved a proposal from Eversource to procure 12.5 percent on the spot market. The Commission issued similar directives to the state's other regulated distribution utilities, Granite State Electric Corporation (which does business as Liberty) and Unitil. Now, Eversource is proposing to comply with the Commission's directive.

Q. Do you have concerns about the Commission's decision to impose on distribution utilities an increasing reliance on spot purchases to serve default energy service load?

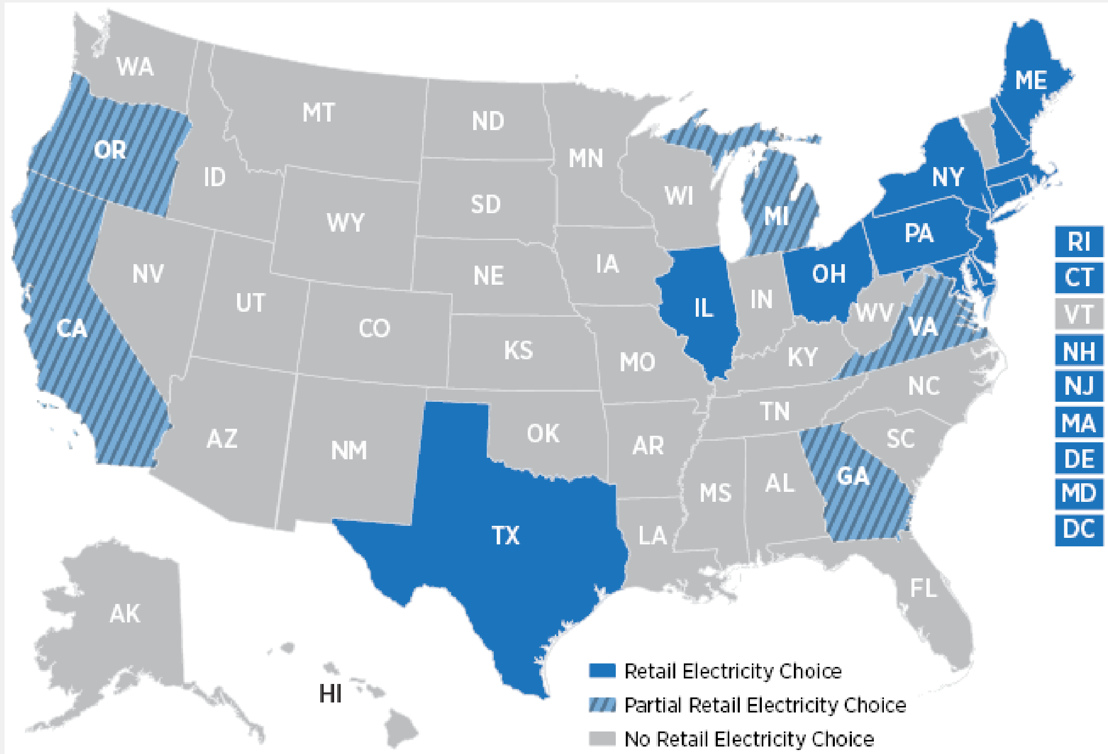
A. Yes, I do. I agree with the Commission that having the utilities enter into a series of six-month all-requirements contracts in order to serve default energy service load did not necessarily serve residential customers well, given the risk premiums embedded in those contracts that have made this service less affordable than it would otherwise have been. I share the Commission's opinion that customers are better off if Eversource and the other investor-owned electric distribution utilities harness the power of markets -- but, as I explain, I propose reliance on a different market than the one for which the Commission has previously expressed approval. My proposal is designed not to discourage the use of default energy service by exposing customers to volatile price swings in real time but, rather, to make default energy service as compelling an alternative as possible in a manner that is fully consistent with New Hampshire's electric industry restructuring statute – the law that authorizes default energy service in the first place.

Q. The 1996 Electric Utility Restructuring Act, RSA 374-F, gives the Commission discretion to discourage the "long-term use, of default service" in RSA 374 F:3 V(c). Should the Commission now exercise that discretion?

A. Not for residential customers. The Act was crafted and ratified before New Hampshire's experiment with retail competition had taken place, in anticipation that the experiment would succeed, but allowing for the possibility that it would fail. The experiment has been a failure, as far as residential customers are concerned. The only type of electricity retailer that has drawn a substantial share of the residential market away from investor-owned utilities (IOUs) is community aggregators, and the latter are defined, as of 2019, as providers of default service in Section 374-F:2 I a of The Act, not as competitive suppliers. The reason for this is that there is an economy of scale in the wholesale purchase and retail resale of electric commodity, documented in the OCA's letter to the Commission filed April 3rd in DE 23-044. This economy of scale precludes competition among a large number of small firms from minimizing the cost of residential service because larger retailers can sell for less, and it makes it difficult for small retailers, competitive suppliers, to compete with large retailers profitably. It is worth noting that most states have not even attempted an experiment with retail choice

Figure I

States with retail electricity choice



Source: National Renewable Energy Laboratory

and that the rapid ascension of the Community Power Coalition of New Hampshire (CPCNH) in terms of market share is attributable to its ability to purchase wholesale power in large quantities. As noted in a recent media account,

> Member towns in New Hampshire's year-old Community Power Coalition are reaping the benefits of banding together to buy electricity on their own.
>
> As of Feb. 1, residential and small commercial customers in the coalition's 16 active member communities will pay a base electricity rate of 8.1 cents per kilowatt-hour, a 26 percent reduction from their already-competitive rate of 10.9 cents per kWh.
>
> Another 29 communities are planning to enjoy the lower rate after they launch their own programs this spring, effectively making the statewide coalition the second-largest electrical supplier in the state…

> ***The coalition uses the collective buying power of all of their residents and businesses to secure competitive rates in the wholesale market.***[1]

Q. Does this suggest that a single retailer could minimize rates by procuring all of the electric commodity for New Hampshire?

A. It is conceivable, but I do not know the points at which the economies of scale would be exhausted. I have found evidence, though, that, in the current configuration of retailers, the decline in average cost associated with an increase in sales volume is greater for New Hampshire's IOUs and the New Hampshire Electric Cooperative than it is nationally, as shown in Table I, from the OCA's letter to the Commission filed six months ago in DE 23-044.[2]

Table I: Proportional decline in unit price for electric commodity associated with an increase in volume for large utilities in New Hampshire

Utility	Retailer effect
Eversource	2.40
NHEC	2.11
Unitil	1.91
Liberty	1.68
USA	1.00

Rather than discouraging long term use of default service provided by the IOUs, the Commission could better minimize rates paid by residential customers by allowing the IOUs to avail themselves of these economies of scale, as the CPCNH is already doing. If the IOUs choose to compete with the CPCNH as providers of default service, the competition between them should lower residential rates. If the economies of scale extend to the whole state's load,

[1] Prevost, L. (2024). Five years later, New Hampshire's community power law is reshaping the electricity market, *Energy News Network*, February 5, 2024. Available at **https://newhampshirebulletin.com/2024/02/05/five-years-later-new-hampshires-community-power-law-is-reshaping-the-electricity-market/**, accessed April 1, 2024 (emphasis added).
[2] OCA memo to the Commission in DE 23-044 (April 3, 2024) (tab 72) at 8.

one might expect the whole state to end up participating in community aggregation, but, again, I do not know the points at which the economies of scale would be exhausted.

Q. The cost of commodity is an expense for the IOUs; they are not allowed to earn a return on it. Why, then, would they want to compete with the CPCNH?

A. For the foreseeable future, if the IOUs find opportunities to make default service more attractive to customers that the CPCNH has not found, they can increase default service load. This would enable them to justify as prudent more investment in distribution, on which they are allowed to earn a competitive return. According to Burke and Abayasekara (2018), although "electricity demand is very price inelastic in the short run, with a same-year elasticity of -0.1…The long-run elasticity is near -1, larger than often believed."[3] This is hardly negligible. In the long run, lower prices lead to higher loads, higher loads lead to more investment in distribution, and more investment in distribution leads to greater profits for the IOUs. It should be noted that if the CPCNH finds opportunities to make default service more attractive to customers that the IOUs have not found, loads will also increase, the IOUs will be allowed to invest more in distribution, and, in turn, earn greater profits. The IOUs have incentive to compete with the CPCNH if and only if they can do a better job. If they can, residential customers will pay lower rates. The Commission should allow them to try.

Q. Are lower rates the only way to make default service more attractive to residential customers?

A. No. The wholesale price of electric commodity is volatile, and it is safe to say that customers want to avoid unexpectedly high bills, especially when their incomes are low. If, for

[3] Burke, P.J., Abayasekara, A. (2018). The price elasticity of electricity demand in the United States, *The Energy Journal* 39(2), 123-146, **https://www.jstor.org/stable/10.2307/26534427**.

example, the Organization of Petroleum Exporting Countries (OPEC) visits a fuel price shock on the market for energy, causing a recession which, in turn, causes a waitress to earn less in tips or lose her job, high bills caused by the increase in the price of energy will be especially painful. The IOUs can make default service more attractive to her by hedging this type of risk on her behalf.

Q. How could the IOUs manage energy price risk for residential customers?

A. Using futures markets, laddering, a live descending clock auction, and bilateral contracts with prices that are positively correlated with customers' incomes; if bills are low when customers' incomes are low, that mitigates volatility in their consumption of goods overall. However, the latter mechanisms are not expected to price electric commodity in ways that leave room for arbitrage between them and futures markets insofar as those who participate in them are price-takers in futures markets; if one mechanism prices electric commodity more (less) attractively to a market participant than the futures market, such participants will change their positions in the futures market, changing the futures price until it is no longer more (less) attractive. For purposes of this testimony, then, I will discuss risk management in terms of futures markets.

Q. If residential price risk were managed using futures markets, would that dilute the economically efficient price signal of spot markets?

A. No. Futures markets are just as much markets as spot markets. If they exist, but are not used, opportunities for mutually beneficial risk sharing may be lost, and pricing all load at the spot price will not be economically (Pareto) efficient.[4] Pareto efficiency, defined as having run out of opportunities to make one person better off without making anyone worse off, is the most

[4] See Arrow, K. (1964). The role of securities in the optimal allocation of risk-bearing, Review of Economic Studies 31(2), 91-96. https://doi.org/10.2307/2296188

modest social welfare criterion in economics, and pure spot pricing can fail to satisfy even that criterion when futures markets exist.

Failure to institute futures markets can intensify spot price risk. Capacity markets operated by regional transmission organizations are a kind of futures market. When generators recover capital expenditures through sales of capacity, they are less dependent on revenues from intermittent sales at spot prices that exceed their operating costs. A failure to institute capacity markets or payments led to the California power crisis twenty odd years ago, and, possibly, to the extended outages in Texas in February of 2021. Spot prices rose to extremely high levels, and the spot market was tight enough that significant loss of load ensued. However conventional in the electricity business, limiting the definition of "the market" to spot (e.g., day ahead and real time) markets is too far from the truth for such a convention to be respected.

In New England, spot prices sometimes exceed operating costs of generators because of congestion on pipelines or transmission lines leading into the region, especially during cold snaps. These high spot prices have enabled generators here to recover significant capital expenditures through spot prices, lowering the prices in the capacity auctions. ISO-NE is moving to replace its three-year forward capacity auction with prompt and seasonal markets that function within a significantly shorter time-frame. If it does, it will be that much more important to manage any longer-term risk to residential rates using the futures market for electric energy.

Q. What futures markets are available to manage price risk for residential electric customers?

A. Primarily the futures market for electricity at the ISO-NE Mass Hub on the New York Mercantile Exchange (NYMEX). The on-peak contract at the Mass Hub is for five MW delivered for 16 hours (80 MWh) during the contract month and the on-peak hours defined by the ISO.[5] An off-peak contract for five MWh "clears in multiples of the number of off-peak hours in the contract month."[6] Prices for both contracts are quoted in dollars per MWh up to five years out.

Because natural gas is generally the marginal fuel source for generation of electricity, it can be instructive to monitor the futures market for pipeline gas at Henry Hub in Louisiana on the NYMEX. The contract for delivery at Henry Hub refers to 10,000 MMBtu during the contract month, and prices are quoted in dollars per MMBtu up to twelve years out.[7] There is also a futures market for basis (transport cost) between Henry Hub and the hubs on the Algonquin pipeline in New England on the Intercontinental Exchange (ICE).[8]

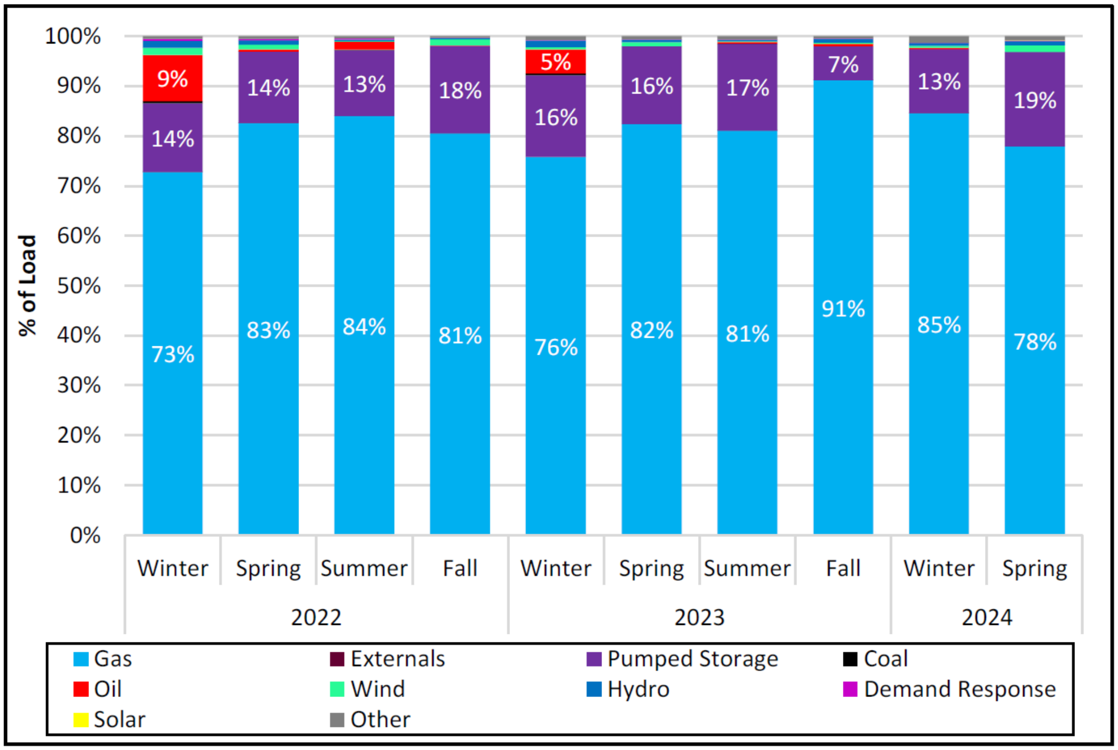
Q. Why are markets for natural gas informative regarding price risk for electric energy in New Hampshire?

A. Because gas-fired generators set locational marginal prices here. The bid accepted from the last generator dispatched during any hour defines the LMP at that generator's pricing node, and LMPs at other nodes only differ according to losses and congestion between nodes. The last generator dispatched is generally fueled by natural gas, as shown in Figure II.[9] The large blue sections of the bars represent gas-fired marginal units in New England, and the substantial purple sections represent nodes at which the ISO-NE system interfaces with adjacent systems. The adjacent systems are in inland New York, Long Island, and Canada. Prices for electricity in

[5] **https://www.cmegroup.com/markets/energy/electricity/nepool-internal-hub-5-mw-peak-calendar-month-day-ahead-swap-futures.contractSpecs.html**, accessed August 30, 2024.
[6] **https://www.cmegroup.com/markets/energy/electricity/nepool-internal-hub-5-mw-off-peak-calendar-month-day-ahead-swap-futures.contractSpecs.html**, accessed August 30, 2024
[7] **https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.contractSpecs.html**, accessed August 30, 2024.
[8] **https://www.ice.com/products/6590124/Algonquin-Citygates-Basis-Future**, accessed August 30, 2024.
[9] ISO-NE Spring 2024 quarterly markets report, p. 22; available at **https://www.iso-ne.com/static-assets/documents/100013/2024-spring-quarterly-markets-report.pdf**, accessed August 30, 2024.

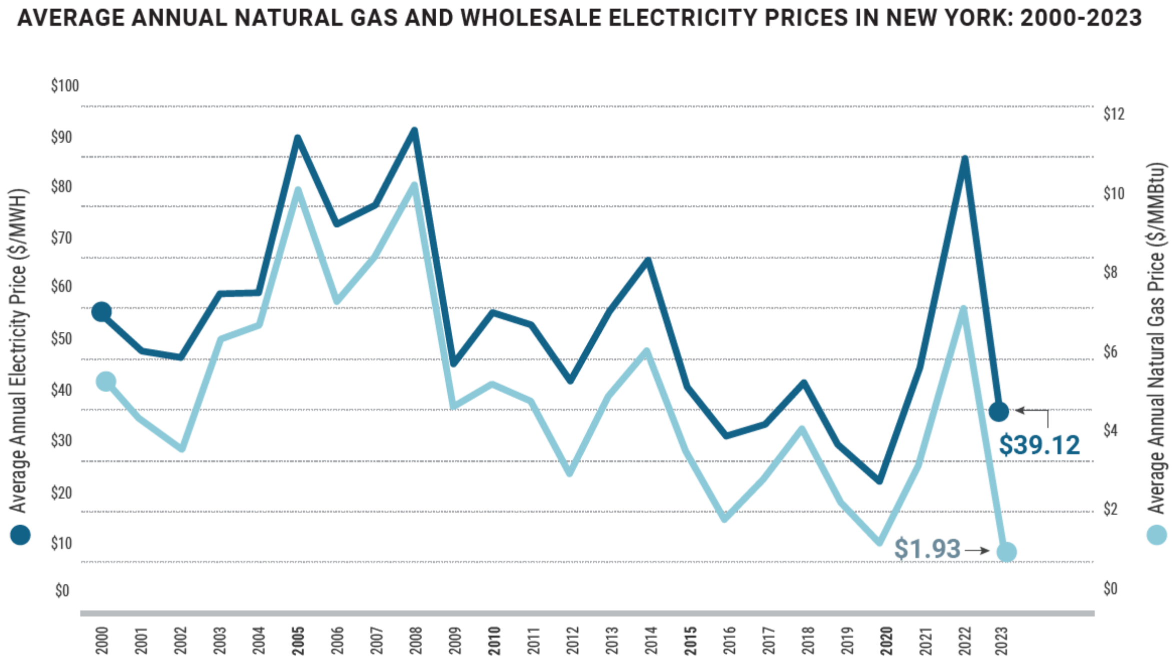
New York are also determined by prices for natural gas, as shown in Figure III.[10] Prices for natural gas, then, are the dominant determinant of LMPs in New England.

Figure II: Real time marginal units by fuel type in ISO New England



[10] NYISO power trends 2024 annual report, p. 33; available at **https://www.nyiso.com/documents/20142/2223020/2024-Power-Trends.pdf/31ec9a11-21f2-0b47-677d-f4a498a32978?t=1717677687961**, accessed August 30, 2024.

Figure III



Q. Would it cost something for the IOUs to hedge price risk using futures at the Mass Hub for residential customers taking default service?

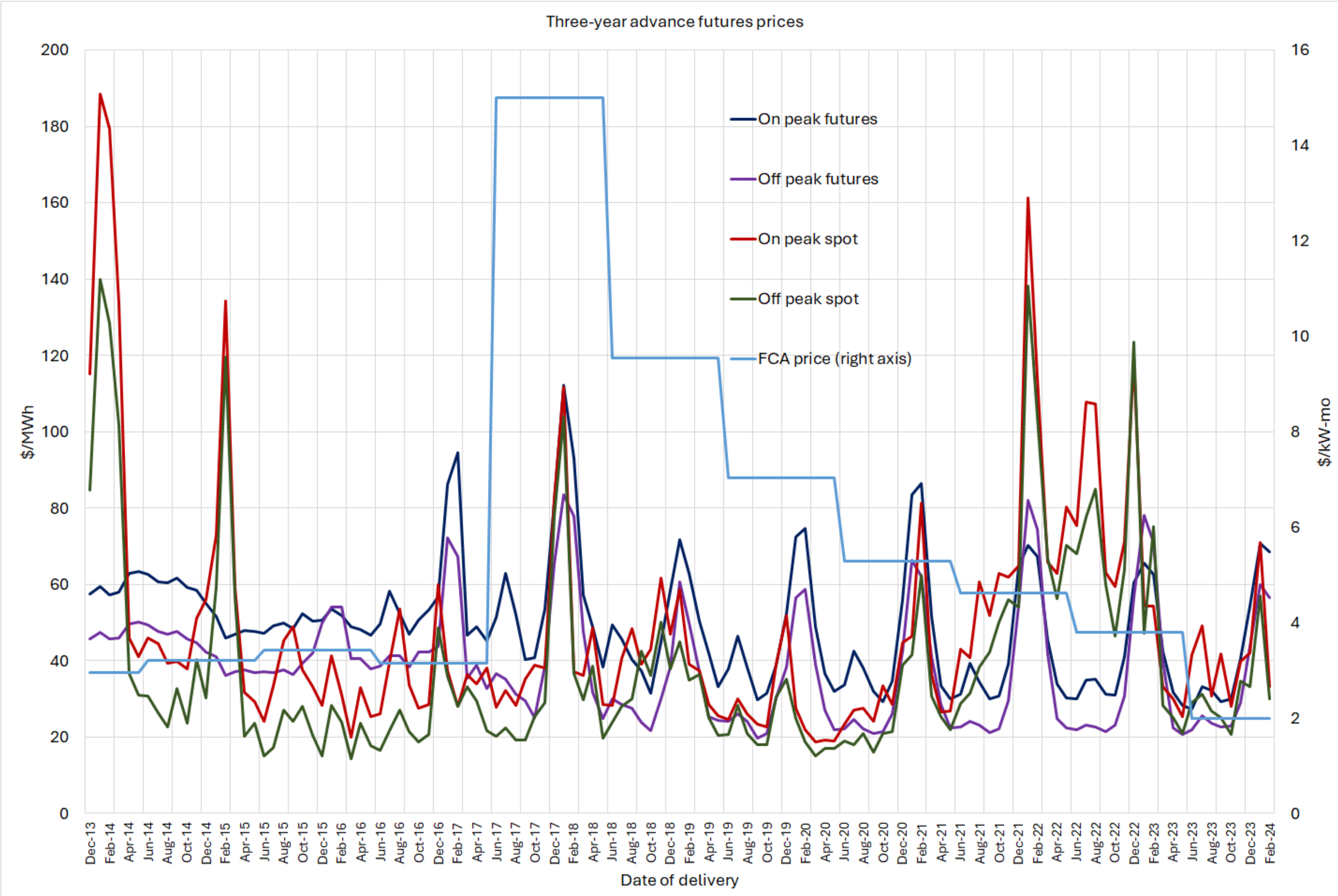
A. If done over long periods of time, likely no; if done over short periods of time, likely yes. Traders in futures markets did not foresee the fuel price shock that followed the Russian invasion of Ukraine. This is shown in Figure IV, which is taken from my testimony in DG 23-087. The figure shows prices for natural gas, but these drive prices for electricity for the reasons I explained earlier in my testimony. Had electric energy been procured in the futures market at the Mass Hub three years in advance, the IOUs could have spared their customers the rate shock of 2022, which our Consumer Advocate described as “unconscionable increases in default energy service prices during the past two years” in a letter to the Commission filed in IR 22-053 and dated February 17, 2023. The letter goes on to say

> This situation…threatens the very foundation of electric industry restructuring. . . .[T]he OCA's counterpart in Maine, the Office of the Public Advocate, recently asked that state's legislature to phase out retail choice for residential customers based on a study…demonstrating that residential customers have, at most, failed to achieve any benefits from the availability of non-utility electric supply. . . . It is tempting to conclude that no one is watching out for residential customers, a state of affairs that cannot be consistent with the intentions of the General Court when it opted for industry restructuring in 1996. . . . In these circumstances, there is an urgent need for the Commission to open an adjudicative proceeding under its Puc 200 contested case rules to determine, with all deliberate speed, the future contours of default energy service procurement.[11]

Residential customers in many types of economic circumstances could have benefited from their retailers' procuring electric commodity three years in advance in the futures market at the Mass Hub for delivery over the ten-year period December 2013 through December 2023 because traders in futures markets did not foresee the fuel price shock of 2022, so that the risk thereof was not reflected in futures prices in 2019. This despite the history of such shocks, engineered by the OPEC, since 1973, as I explain in my testimony in DG 23-087.

[11] OCA Letter of February 17, 2023 (tab 63) in Docket IR 22-053 at 1-2.

Figure IV


Three-year advance futures prices
On peak futures
Off peak futures
On peak spot
Off peak spot
FCA price (right axis)
$/MWh
$/kW-mo
Date of delivery
0
20
40
60
80
100
120
140
160
180
200
0
2
4
6
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Feb-24

The potential for mutually beneficial risk sharing between retailers and customers in the labor force, who are either working or seeking work, is shown in Table II. (The calculations are performed numerically in 24-046_2024-09-23_Exh_1.xlsm, and symbolically in the appendix.) The cost to the utility is the present value in 2024 of the difference between the cost of procurement three years in advance on the futures market at the Mass Hub and the spot price there. The time value of money is assumed to be eight percent plus inflation for a retailer. The cost to the retailer of hedging is negative in Table II because the futures markets in 2019 did not reflect the coming shock of 2022.

The value to the customer is the difference between the present value of income less the cost of buying electric commodity at the futures price and the present value of income less the cost of buying electric commodity at the spot price. Income is adjusted for the probability of being unemployed, where, if a worker is unemployed, her benefits are assumed to be half of what her income would be if she were employed, and the probability of her being unemployed is the rate of unemployment in the industry in which she works during the month in question. The time-value of money is assumed to be 8 percent plus inflation for a typical customer, 17 percent plus inflation for a food service worker, and 2 percent plus inflation for a scientific researcher, based on the assumption that the food service worker has consumer debt, and that the researcher has a savings account to draw on.[12]

[12] Data on employment, unemployment, and earnings were accessed September 4, 2024 through New Hampshire Employment Security (NHES) at **https://www.nhes.nh.gov/elmi/statistics/qcew-quart-data.htm**. According to the Social Security Administration, "In most of the States, the formula is designed to compensate for a fraction of the usual weekly wage (normally about 50%)." *See* **https://www.ssa.gov/policy/docs/progdesc/sspus/unemploy.pdf**, accessed September 9, 2024.

Table II: Costs to retailers and benefits to customers of procuring electric commodity three years in advance for delivery December 2013 through December 2023

If all 747465 customers in the labor force were typical

Cost to retailer	Value to customer	Net	
-1.04	0.12	1.16	2024$/MWh
-3.27	$0.38	3.65	Annual per capita (2024$)
-$2,473,847	$286,372	$2,760,218	Annual statewide (2024$)

Only the 52021 customers working in food service

Cost to retailer	Value to customer	Net	
-1.04	0.31	1.35	2024$/MWh
-1.66	$0.50	2.16	Annual per capita (2024$)
-$86,103	$26,041	$112,144	Annual statewide (2024$)

Only the 3053 customers working in scientific research and development

Cost to retailer	Value to customer	Net	
-1.04	-0.01	1.03	2024$/MWh
-4.99	-$0.03	4.96	Annual per capita (2024$)
-$15,435	-$98	$15,336	Annual statewide (2024$)

Sources: Standard & Poor's Global Capital IQ (**https://www.spglobal.com/marketintelligence/en/solutions/sp-capital-iq-pro#five-new-reasons**, accessed September 9, 2024), Energy Information Administration (EIA) (**https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm**, accessed September 9, 2024), and the Federal Reserve Bank of Saint Louis (**https://fred.stlouisfed.org/series/CPIAUCSL**, accessed September 9, 2024)

The $/MWh figures for retailers can be referred to as the risk premium they would have had to pay to hedge spot price risk, and the $/MWh figures for customers can be referred to as the risk premium they would have been willing to pay to have spot price risk hedged for them, three years in advance in the futures market at the Mass Hub. If the former is negative and the latter is positive, then there was potential for mutually beneficial risk sharing between the retailer and the customer. The value to the customer working in scientific research and development was only slightly negative. He is virtually indifferent between procurement in the futures market three years in advance and procurement in the spot market.

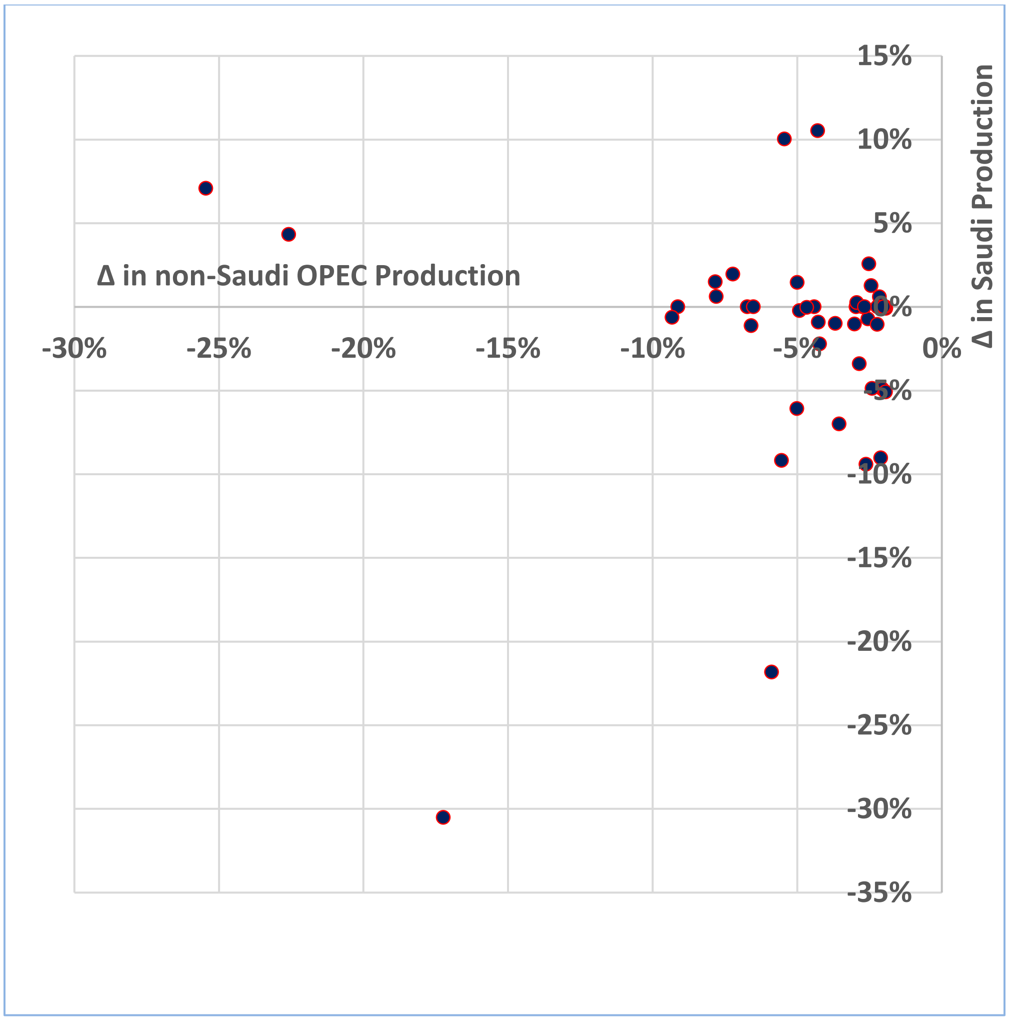
Q. Why do you suggest that this hedging strategy would only work over the long term?

A. If I remove 2022 from the time series, the risk premium for the retailer increases to (a positive cost of hedging of) $5.98/MWh, and decreases to (a negative value of having risk hedged on one's behalf of) -$0.59/MWh for a typical customer, -$0.59/MWh for a food service worker, and -$0.61/MWh for a scientific researcher. Without the global fuel price shock, there would have been no potential for mutually beneficial risk sharing three years in advance over the ten-year period. Setting aside supply shocks, spot prices are driven enough by macroeconomic activity, which influences demand, that customers' bills rise and fall more with their incomes, so that their volatility helps to smooth their consumption of goods overall enough to make spot purchases more attractive than purchasing on the futures market.

Therefore, procuring electric commodity three years in advance would benefit both retailers and customers, but only if the strategy were adhered to long enough to encompass a global fuel price shock, which futures markets will have a hard time anticipating. These shocks have occurred throughout the "OPEC Era" of fuel pricing, but OPEC is opportunistic about perpetrating them. OPEC's opportunism is implied in Figure V. During the 44 largest month-to-month percentage drops in non-Saudi OPEC production since 1973, Saudi Arabia increased production 12 times, left production unchanged 10 times, and decreased production 22 times; during 11 of these, the percentage drop in Saudi production exceeded that in non-Saudi OPEC production. Saudi Arabia, OPEC's "swing producer", uses that role to exacerbate, rather than offset, disruptions in supply, surely with the assent of other members of the cartel. It is reasonable to expect it to do so in the future, but even OPEC does not know when the next shock is coming, so traders in futures markets do not know, either, at least not three years in advance.

Once a shock becomes apparent, though, futures prices for delivery in the near- and medium-term rise, and the opportunity to hedge spot price risk at negative cost has been missed.

Figure V: Changes in Saudi and non-Saudi OPEC production when the latter is disrupted



Source: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, **https://www.eia.gov/totalenergy/data/monthly/index.php#international**, accessed March 22, 2023

Q. Why did you choose a cycle three years in length?

A. Assuming that natural gas was on the margin in generation of electricity, I estimated a long cycle in spot prices at Henry Hub, and surmised that it was three years in length. 24-046_2024-09-23_Exh_3.xlsb shows the result in months in Cell H333. Entries in Column H above that cell are the length of time between the date in the given row and the next time that prices, rounded to the nearest 25 cents, were the same, but moving in the opposite direction. Cell H333 shows the average for Column H: 36 months. Hedging this far in advance would protect customers from global fuel price volatility like that observed after Russia's invasion of Ukraine. Henry Hub is not only a national but an international hub, located on the Gulf Coast near a great deal of LNG export capacity, so prices there influence and respond to prices globally. Substitution of gas for coal will continue worldwide for many years to come, and the three-year price cycle at Henry Hub is consistent with the lead time for constructing a combined cycle gas-fired generator. Combined cycles are still being built in some parts of the United States, as well[13], and the plant factors for those are higher than for solar and wind.

Q. How should electric energy procured three years in advance be priced?

A. At the price for delivery under the futures contract at the Mass Hub plus congestion and loss components in the ISO-NE real time market at the relevant node in New Hampshire at the time of delivery. (I am not proposing or opposing sharing of comparatively small intra-regional basis risk.) As shown in Table II, a majority of customers would benefit. Those with low incomes working in industries that depend on discretionary spending of consumers would benefit the most, and those with high incomes and secure jobs would lose little or nothing.

Q. How much electric energy should an IOU procure three years in advance?

A. Whatever load the Commission would have an IOU procure in the spot market three years hence should be procured in the futures market at the Mass Hub instead, beginning as soon as possible. If the IOU ends up having less load than that to serve, it should be the responsibility

[13] **https://www.energy.gov/eere/vehicles/articles/fotw-1304-august-21-2023-2023-non-fossil-fuel-sources-will-account-86-new#:~:text=For%202023%2C%20added%20capacity%20will,for%2014%25%20of%20the%20total**, accessed September 9, 2024.

of the IOU to settle the futures contracts on the open market; no stranded costs could be recovered. The IOU assumes the load risk, but that is good risk sharing because most shareholders are in a better position to assume risk than most residential customers. Benefits to customers of better risk sharing will increase loads, increasing the amount of investment in distribution an IOU can justify as prudent. The rate of return they are allowed on this investment is considerably higher than a risk-free rate of return, and the difference is nothing but a risk premium paid to shareholders.

Q. Therefore, in light of your recommendations, how should the Commission resolve this docket as it concerns residential customers?

A. I recommend that the Commission direct Eversource to maintain the status quo with respect to the upcoming procurement, covering the six-months beginning on February 1, 2025, and direct the Company to file a proposal centered on reliance on futures markets in three months' time, for effect with the procurement covering the six months beginning on August 1, 2028. In the meantime, the Commission may experiment with greater procurement on the spot market, but it does so at the risk that the next global fuel price shock will occur during that time.

Q. Does this conclude your testimony?

A. Yes.

Appendix

Equation (1) was estimated using quarterly data from NHES, EIA, and the Federal Reserve Bank of Saint Louis from 2000 through 2023. Monetary figures were in 2024$.

$$\begin{aligned} w_{it} &= \underset{0.03}{7.08} + f_i - \underset{0.00}{0.03}\,q_2 - \underset{0.00}{0.02}\,q_3 + \underset{0.00}{0.10}\,q_4 \\ &\quad + \underset{1.10E-06}{6.44E-06}\,L_{it} - \underset{1.68E-02}{8.57E-02}\,hh_t + \underset{0.00}{0.05}\,t \end{aligned} \tag{1}$$

where w_{it} is the average weekly wage in Industry i, f_i is a fixed industry effect, q_s is an indicator variable for Calendar Quarter s, L_{it} is average employment in Industry i, hh_t is the spot price at Henry Hub in 2024$/MMBtu, whose negative coefficient reflects the negative economic impact of fuel price shocks, and the numbers below the coefficients are their standard errors of estimate. Equation (2) describes a trend in real wages.

$$w_{it} = \underset{0.08}{3.85} + f_i - \underset{0.00}{0.02}\,q_2 - \underset{0.00}{0.16}\,q_3 + \underset{0.00}{0.03}\,t + \underset{0.01}{0.44}\,w_{it-1} \tag{2}$$

Monthly average employment and prices at Henry Hub were substituted into Equation (1) to predict monthly wages.

Unemployment was assumed to be zero when wages predicted using Equation (1) in an industry exceeded a 95% upper bound implied by Equation (2), and proportional to the amount by which the monthly wages predicted using Equation (1) fell short of the 95% upper bound, which was 26 percent above the trend. Average unemployment statewide over the sample period was restricted to equal its actual average of 4.0 percent. The standard deviation over all industries and months in the rate of unemployment was 1.6 percent, for a coefficient of variation of 0.43.

Well-being for a customer in the labor force was given by

$$E(U) = P_E\left(W_E - B_M\right)^{1-\sigma} + \left(1 - P_E\right)\left(W_{-E} - B_M\right)^{1-\sigma} \qquad (3)$$

where $E(U)$ is expected "utility", P_E is the probability of being employed, W_E is monthly income if employed, W_{-E} is monthly income if unemployed, $\sigma = 3$, based on Hall (1988)[14], and B_M is the customer's electric bill when commodity is procured in Market M, either futures or spot. Monthly residential load, on and off peak, was taken from Liberty Utilities[15] and adjusted for the difference from average income using an income elasticity of demand of 0.61 from Cserekly ei (2020)[16]. To monetize expected utility from Equation (3), certainty equivalent income was calculated as

$$W_{CE} = \left(P_E\left(W_E - B_M\right)^{1-\sigma} + \left(1 - P_E\right)\left(W_{-E} - B_M\right)^{1-\sigma}\right)^{\frac{1}{1-\sigma}} \qquad (4)$$

and the difference in the present value of these between futures and spot procurement was taken to be the risk premium the customer would be willing to pay.

[14] Hall, R.E. (1988). Intertemporal substitution in consumption. *Journal of Political Economy*, 96(2). **https://doi.org/10.1086/261539**

[15] **https://new-hampshire.libertyutilities.com/allenstown/commercial/data.html**, accessed September 3, 2024.

[16] Csereklyei, Z. (2020). Price and income elasticities of residential and industrial electricity demand in the European Union, *Energy Policy* 137. **https://doi.org/10.1016/j.enpol.2019.111079**

EDUCATION

Ph.D. in Economics, Brown University, Providence, RI, 2007
M.A. in Economics, Brown University, Providence, RI, 1999
B.A. in Economics with departmental honors, University of Oregon, Eugene, OR, 1986

EXPERIENCE

New Hampshire Office of the Consumer Advocate, Concord, NH, August 2023 – present
- Expert testimony and analysis in regulatory proceedings on behalf of residential customers of public utilities in New Hampshire
- Education of customers

Rivier University, Nashua, NH, January 2020 – present
- Teach business economics and macroeconomics

The Economic Utility Group, Nashua, NH, February 2021 – June 2021, July 2022 – July 2023
- Forecasted wages and employment in the skilled trades with Senior Economist at Construction Industry Resources
- Forecasted volatile upstream fuel prices and climate damages
- Forecasted electric vehicle and non-EV electrification load for Hitachi Energy USA

Hitachi Energy USA, Nashua, NH, June 2021 – June 2022
- Analysis, modeling, forecasting, and reporting on wholesale power markets, especially in Mexico, using PROMOD® (a production cost model)

Elevation Direct Corporation, Nashua, NH, July 2015 – January 2021
- Jointly sponsored testimony before the Rhode Island PUC on the employment impacts of Clear River Energy Center (CREC) for the Rhode Island Building and Construction Trades Council; individually sponsored rebuttal testimony on the need for CREC
- Used Aurora® (a capacity expansion and production cost model) to evaluate potential purchase of Termoelectrica de Mexicali, a combined cycle natural gas-fired generator
- Used Aurora to forecast wholesale electric prices in Michigan and sponsored testimony on behalf of Michigan Public Service Commission staff in a case regarding a purchased power agreement for the output of the Palisades nuclear plant
- Work in restructured wholesale power market in Mexico
  - Provided forecasts of gross state product, loads, and fuel, energy, congestion, loss, ancillary service, and capacity prices, as well as prices of clean energy certificates and social costs of emissions in evaluations of pumped storage, combined-cycle gas, internal combustion, and wind and solar facilities; co-authored market studies done using Aurora, Plexos, and Encompass (capacity expansion and production cost models)
  - Assembled Mexican database and used Aurora to model expansion and operation of power grid for several independent generators
  - Co-authored a report on the economics of introducing liquefied natural gas to southern Baja California
  - Estimated a weighted average cost of capital to Comisión Federal de Electricidad (CFE)
  - Trained employees of CFE in load forecasting
  - Estimated Herfindahl-Hirschman indices of market concentration following breakup of CFE under Mexican energy reform

Universidad del Pacifico, Jesús María, Lima, Peru, September 2014
- Taught topical graduate course in energy economics.

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Economic Insight, Portland, OR, January 2010 – March 2013
- Used Aurora to model electric resource planning in the Pacific Northwest
- Used Aurora to estimate trade benefits of Entergy and South Mississippi Electric Power Association joining regional transmission organizations, sponsored testimony before the Mississippi Public Service Commission (MPSC)
- Assessed application to install pollution controls on a coal plant; jointly testified with Sam Van Vactor before the MPSC
- Estimated dollars of spending per employee by generating technology
- Analyzed issues regarding pricing and royalties in geothermal and natural gas leases in California and Texas;
- Analyzed pricing and alleged use of market power in California power crisis
- Estimated lost earnings in a wrongful death lawsuit and testified to report
- Editor of scholarly research written by non-native speakers of English (intermittent)

Pacific University, Forest Grove, OR, August 2008 - May 2009
- Taught principles of microeconomics, environmental economics, and international trade

New York Department of Public Service, Albany, NY, August 2006 - December 2007
Eastern Connecticut State University, Willimantic, CT, August 2005 - May 2006
- Taught principles of microeconomics

Allan M. Feldman, Ph.D., Providence, RI, 2002-2003
- Worklife evaluation for litigation related to personal injury or wrongful death

Brown University, Providence, RI, 1999-2002
- Research and teaching assistance in valuation of individual earning capacity, industrial location in Indonesia, and principles of microeconomics and macroeconomics

Synapse Energy Economics, Cambridge, MA, July 1998 - February 1999
- Evaluated forecasts of electricity prices submitted in “stranded-cost” claim by four Maryland utilities

Bonneville Power Administration, Portland, OR, September 1988 - June 1997
- Authored and testified to marginal cost analysis in 1996 rate case before FERC
    - Helped prepare inputs to and interpreted and applied results of Power Marketing Decision Analysis Model (PMDAM) to rate design and to planning and evaluation of resources
    - Prepared and conducted public meetings on analysis and its implications for rate design
    - Fielded and incorporated comments from a variety of participants
    - Authored rate case study, documentation, and testimony
- Research on marginal costs of generating and marketing hydropower on the West Coast
- Prepared workshop briefing material, rate case studies, and documentation supporting marginal cost analysis and other rate-related issues as assigned
- Evaluated contracts for disposition of wholesale power

Economic Insight, Portland, OR, May 1988 - September 1988
- Surveyed forecasts of electricity prices and estimates of demand elasticities related to litigation over Washington Public Power Supply System bond defaults

ECO Northwest, Eugene, OR, July 1986 - August 1987
- Worklife evaluation for litigation related to personal injury and wrongful death; wrote company training manual on the subject

Changsha Normal University of Water Resources and Electric Power, Changsha, Hunan, PRC, August 1987 - January 1988; Brown University, Providence, RI, Summer 2001
- Taught English as a second language

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RESEARCH

Vatter, M. (2024). Is LNG a bridge fuel in the mitigation of global warming: a critical review of studies at the EDF, NRDC, and Bloomberg, *IAEE Energy Forum*, 1st quarter 2024, **https://www.iaee.org/newsletter/issue/116**

Vatter, M. (2022). Pricing global warming as a mortal threat. United States Association for Energy Economics (USAEE) Working Paper No. 21-491, **http://ssrn.com/abstract=3821603**, and IAEE Conference Proceedings, online, June 7-9, 2021, **https://www.iaee.org/proceedings/article/17059**

Vatter, M., Van Vactor, S., and Coburn, T. (2022). Price responsiveness of shale oil: a Bakken case study. *Natural Resources Research*, 31:1, **https://doi.org/10.1007/s11053-021-09972-9**, and IAEE Conference Proceedings, Montreal, May 29-Jun 1, 2019, **https://www.iaee.org/proceedings/article/16313**

Vatter, M. (2020). Stratified zoning in central cities. *Journal of Housing Economics*, 50, **https://doi.org/10.1016/j.jhe.2020.101716**

Vatter, M. (2019). OPEC's risk premia and volatility in oil prices. *International Advances in Economic Research*, 25:2, DOI: **10.1007/s11294-019-09734-7**

Vatter, M., Suurkask, D. (2018). The impact of trade with the United States on electric loads in Mexico. *Heliyon*, 4:8, **https://doi.org/10.1016/j.heliyon.2018.e00717**, and *IAEE Energy Forum*, 2nd quarter 2017, **https://www.iaee.org/en/publications/newsletterdl.aspx?id=406**

Vatter, M. (2017). OPEC's kinked demand curve. *Energy Economics*, 63, **https://doi.org/10.1016/j.eneco.2017.02.010**

Vatter, M. (2017). Stockpiling to contain OPEC. USAEE Working Paper No. 17-136, **http://ssrn.com/abstract=912311,** and USAEE Conference Proceedings, New Orleans, December, 2008, **https://www.iaee.org/proceedings/article/17512**

Vatter, M. (2017). Social discounting with diminishing returns on investment, **http://ssrn.com/abstract=1078502**

Vatter, M., Barney, F. (2016). Macroeconomic risk and residential rate design. USAEE Working Paper No. 15-208, **http://ssrn.com/abstract=2596258**

Vatter, M. (2008). OPEC's demand curve, **http://ssrn.com/abstract=1127642**, reviewed at **http://knowledgeproblem.com/2008/05/14/**

Peer Reviewer for *Land Economics*: effects of endowments of petroleum resources on corruption, 2008; hedging in coal contracts under the acid rain program, 2010-11; suburban agriculture as an amenity, 2012; prorationing versus unitization in the U.S. petroleum industry in the 20th century, 2013

STREAMING MEDIA

International Atlantic Economic Society video: Nice world economy you have there; be a shame if something should happen to it, temporarily available at **https://www.iaes.org/**, accessed June 15, 2022

IAEE webinar: Is another oil price shock possible, and would it matter? January 11, 2021, **https://www.iaee.org/en/webinars/webinar_vatter.aspx**

USAEE podcast: OPEC as a destabilizing influence, July 21, 2020, **https://www.usaee.org/podcasts.aspx**

Video: **Discussing transmission costs with New Hampshire Senate Energy and Natural Resources Chair Kevin Avard**, **https://www.youtube.com/watch?v=QRkLdLplz9Y&feature=youtu.be&fbclid=IwAR2Euva286vNRa5Lit0RstjHwtPuV5a_t439Cml4Z8S2WHYptXNdJ40vkZs**

Video: **Discussing manufacturing, net metering rate design, and transmission costs on** ***Perspectives*** **with David Schoneman**, **https://youtu.be/m9YRY3U-DzM**

AWARDS

Twelve monetary awards for job performance at Bonneville Power Administration
Award for best undergraduate research project in economics at University of Oregon; examined deregulation of U.S. airline industry

OTHER ACTIVITIES

Monitored the House Science, Technology, and Energy Committee in Concord, NH for the Northeast Energy and Commerce Association
Founded and managed "Micro Lunch" seminar, Brown University, 2001-2002
Role of expert witness in Lewis & Clark Law School's mock personal-injury litigation, 1996
Peer Advisor, Department of Economics, University of Oregon, 1984-1986

MEMBERSHIPS

International and United States Associations for Energy Economics; Northeast Energy and Commerce Association; Northeast Energy and Commerce Association; New Hampshire Business and Industry Association, Manufacturing and End Users Policy Committee

TESTIMONIALS

"We asked Marc to provide us with a forecast of future locational marginal prices under two different scenarios, which he managed very well. He provided us with testimony that was on point and met our needs." Lauren Donofrio, Assistant Attorney General, Public Service Division, State of Michigan

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"Marc Vatter provided joint testimony with Sam Van Vactor on behalf of Staff in 2010 regarding Mississippi Power's application to install pollution controls on the Victor J. Daniel coal-fired generator. He brought to light critical issues regarding uncertainty over natural gas prices that bore on the decision to install scrubbers. We hired the two again in 2012 in a proceeding on integrating Entergy's transmission assets into a regional transmission organization. Marc added significant detail representing the state of Mississippi to a production cost and capacity expansion model that he used to quantify the effects of integration. A number of consultants engaged in similar efforts, and Marc's analysis was of superior quality." Dr. Christopher Garbacz, Director, Economics and Planning Division, Mississippi Public Utilities Staff

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