**STATE OF NEW HAMPSHIRE**

**BEFORE THE**

**PUBLIC UTILITIES COMMISSION**

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| **Northern Utilities Inc., New Hampshire Division** | ) | |
| **Petition for Expedited Approval of** | ) | **Docket DG 23-087** |
| **Empress Capacity Agreements** | ) | |
| | ) | |

**Direct Testimony of**

**Marc Vatter**

**Director of Economics and Finance**
**Office of the Consumer Advocate**

**December 14, 2023**

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

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

**Q. How long have you worked for the OCA?**

A. I have been employed by the OCA since August 25th of this 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 sponsored testimony before the FERC, the Mississippi PSC, the Michigan PSC, and the Energy Facilities Siting Board of the Rhode Island PUC, and I am currently sponsoring testimony before the New Hampshire Commission in Docket DE 23-039.

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

A. The landed cost analysis reported in Table VI-8 on page 5 of Exhibit Northern-FXW-2 10.5.23 CONFIDENTIAL runs through 2028, though the Empress contracts extend to 2054. The main purpose of my testimony is to examine the commodity price risk associated with the contracts using a long term forecast of fuel prices, with particular attention to the effect of construction of liquefaction trains on the Pacific Coast in British Columbia. The distinguishing feature of the forecasting model I use is that it forecasts the general pattern of global fuel price shocks, based on the history of such shocks, and their profitability to the Organization of Petroleum Exporting Countries (OPEC). The model draws heavily on research I published in

Vatter (2017)[1], Vatter (2019)[2], and Vatter (2022)[3]. Implementation of the model is done in the Excel file Attachment 1 MHV DG 23 087 CONFIDENTIAL.xlsb. Documentation and Excel files implementing the forecasting model, without reference to the Empress contracts, are available here: **http://www.appliedecon.net/long-term-fuel-price-forecast.html**.

I also discuss the benefits of the Empress contracts to residential electric ratepayers, as they will lower both the cost of electric commodity and the price of Regional Greenhouse Gas Initiative (RGGI) emissions allowances, which are passed through to residential ratepayers.

**Q. Please summarize the OCA's position regarding whether The Commission should deem the Empress contracts "prudent".**

A. The OCA supports approval of the contracts, but The Commission should require Northern to evaluate available strategies for hedging natural gas commodity price risk, including, but not necessarily limited to, purchasing Japan Korea Marker LNG on the futures market, and signing long term contracts for purchase of pipeline gas in Alberta, or additional LNG on the coast in New England.

**Q. Will LNG be available for import in New England going forward?**

A. The declining volume of deliveries of LNG to New England in recent years indicates that import capacity should be available to support such contracts. The declining volume in Figure

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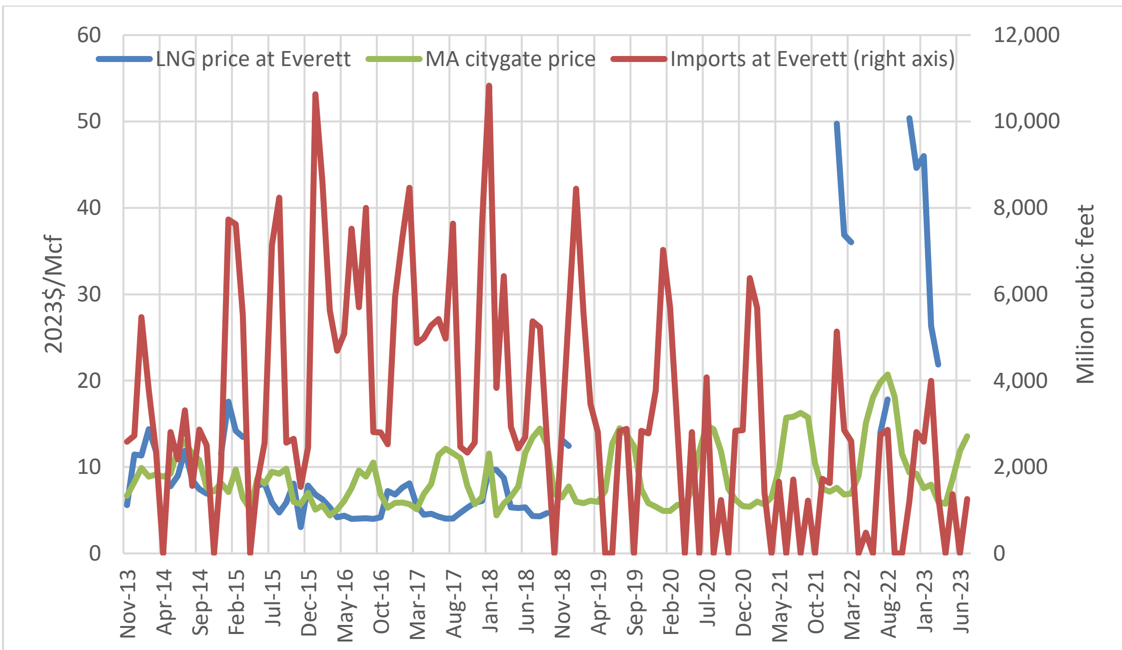
[1] Vatter, M. (2017). OPEC's kinked demand curve. *Energy Economics* 63. https://doi.org/10.1016/j.eneco.2017.02.010. Slides available at https://www.usaee.org/aws/USAEE/asset_manager/get_file/526528?ver=0, with voiceover under "OPEC as a Destabilizing Influence - 7/20/2020" at **https://www.usaee.org/aws/USAEE/pt/sp/podcasts**.

[2] 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. Video available at https://www.youtube.com/watch?v=lU5zqH4X0FI, accessed April 10, 2023.

[3] Vatter, M. (2022). Pricing global warming as a mortal threat. USAEE Working Paper No. 21-491, Available at SSRN: https://ssrn.com/abstract=3821603 or http://dx.doi.org/10.2139/ssrn.3821603. An earlier version was also presented at a virtual conference of the International Association for Energy Economics, June 7-9, 2021, https://www.iaee.org/proceedings/article/17059. Video available at https://www.youtube.com/watch?v=G5of9Qgrdsc&t=1448s.

II-6 on page 24 of Exhibit Northern-FXW-2 10.5.23 CONFIDENTIAL is substantially driven by prices of both LNG and pipeline gas. Using the data shown in Figure 1, I estimate the price elasticity of demand for imports at the Everett LNG import terminal to be -0.35 with respect to the price of the imports themselves, and 0.28 with respect to the Massachusetts citygate price. Data and calculations are shown in the Excel file Attachment 2 MHV DG 23 087.xlsb.

Figure 1: Price and volume of imports at Everett LNG terminal, and MA citygate price



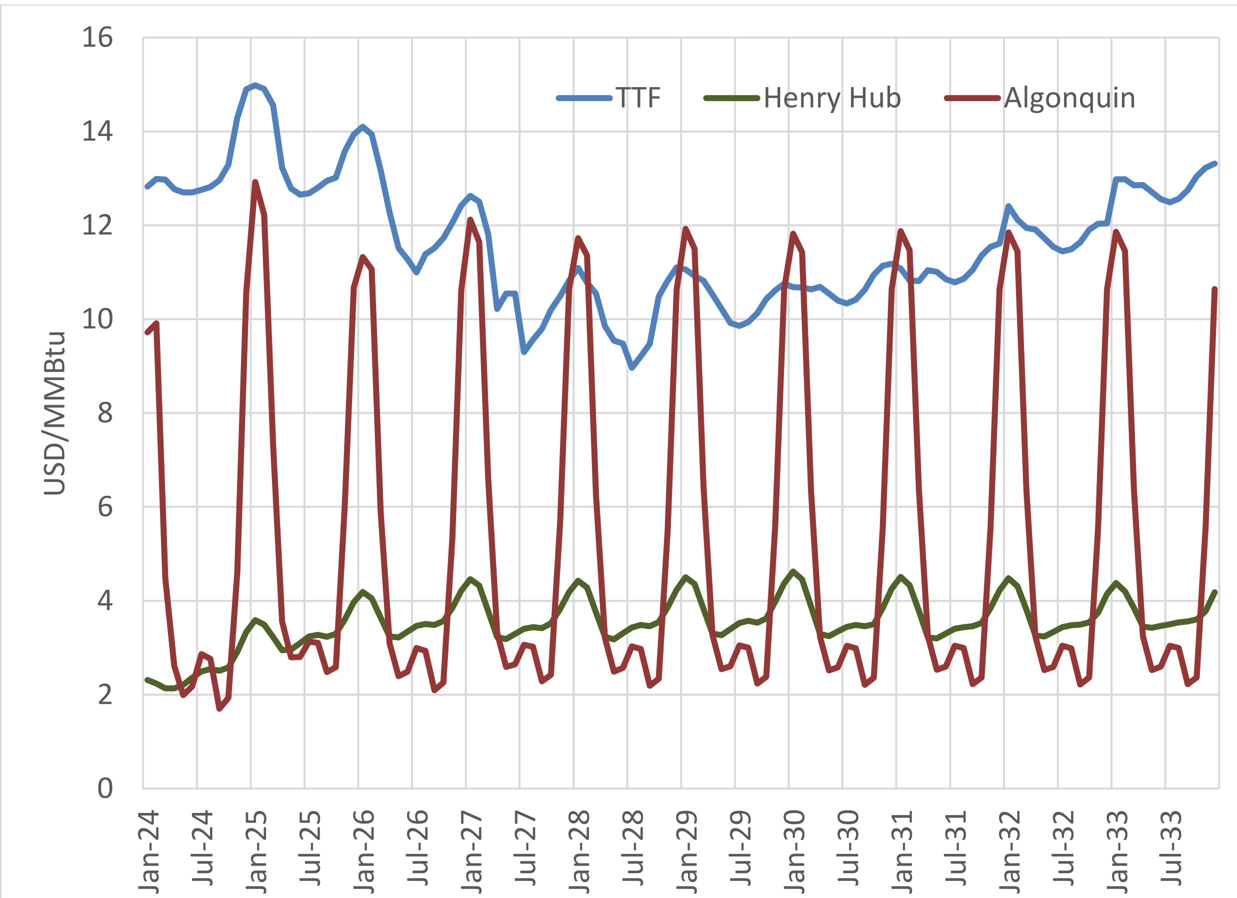

Source: Energy Information Administration (EIA)

There is a tension between arguing that gas is dear in New England and suggesting that owners of infrastructure capable of providing gas here would retire that infrastructure, as Northern does. Figure 2 shows recent futures strips for European LNG (TTF) and American pipeline gas (Henry Hub, Algonquin citygate).[4] To July 2028, the former is in backwardation,

[4] **https://www.cmegroup.com/markets/energy/natural-gas/dutch-ttf-natural-gas-calendar-month.settlements.html#tradeDate=10%2F26%2F2023**, accessed December 13, 2023;

and the latter are in mild contango. Given the estimated elasticities at Everett, inasmuch as these futures prices are good predictors of spot prices, volumes at Everett should rise. The present time, then, may be a good opportunity to contract for future deliveries of additional LNG to New England, while import capacity is plentiful.

Figure 2: TTF, Henry Hub, and Algonquin futures strips




**https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.settlements.html#tradeDate=10%2F26%2F2023**, accessed December 13, 2023; **https://www.ice.com/report/142**, accessed December 13, 2023

Unless volumes rise too much, a reasonable assumption is that the excess import capacity allows one to focus on a global forecast of LNG prices without adding a congestion premium at the importation and regasification facilities locally.

**Q. Please describe the risk associated with expanded liquefaction capacity in British Columbia.**

A. According to the Canadian Association of Petroleum Producers (CAPP), four new or expanded liquefaction facilities are set to come online in British Columbia between 2025 and 2028, fed by natural gas sourced in British Columbia and Alberta.[5] The currently low prices in Alberta could be raised substantially by competing Asian buyers because a congestion premium, in the price they would pay for that gas, could be lowered significantly when the new liquefaction capacity begins operations. This type of phenomenon is occurring elsewhere as the natural gas industry becomes better linked globally. A stark example is the sometimes negative prices at the Waha Hub for associated gas from the Permian Basin in 2019 and 2020, to which additional takeaway capacity put a stop.[6] As the industry globalizes, it will better resemble, and compete with, the petroleum industry, which has been globalized for decades.

Asia already accounts for 70 percent of global LNG demand, and several analysts are bullish about future growth.[7] "Pointing to some 200 scenarios devised by the Intergovernmental Panel on Climate Change that are Paris-compliant, Woodside CEO Meg O'Neill said gas would be needed under most outcomes.

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[5] **https://www.capp.ca/explore/natural-gas-and-the-lng-opportunity-in-british-columbia/**, accessed December 11, 2023.

[6] EIA; **https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/09_08/**, accessed December 11, 2023.

[7] Tan, C. (2023). Industry stays bullish on Asian LNG demand. **https://www.energyintel.com/0000018b-61ee-d826-a3cb-e9fe32b50000#:~:text=Asian%20LNG%20players%20are%20not,of%20a%20peak%20before%202030**., accessed December 11, 2023.

> If you look at the economic growth projections of China, South Asia and Southeast Asia that are likely to happen and the decarbonization objectives they have set, we absolutely believe LNG will be an important part of the mix,

she said. O'Neill stressed the need for more LNG supplies to ensure affordable prices for emerging markets like Pakistan and Bangladesh in South Asia.

> We need to get them on LNG and off coal,

she said."

**Q. Briefly describe your forecast of global fuel price shocks.**

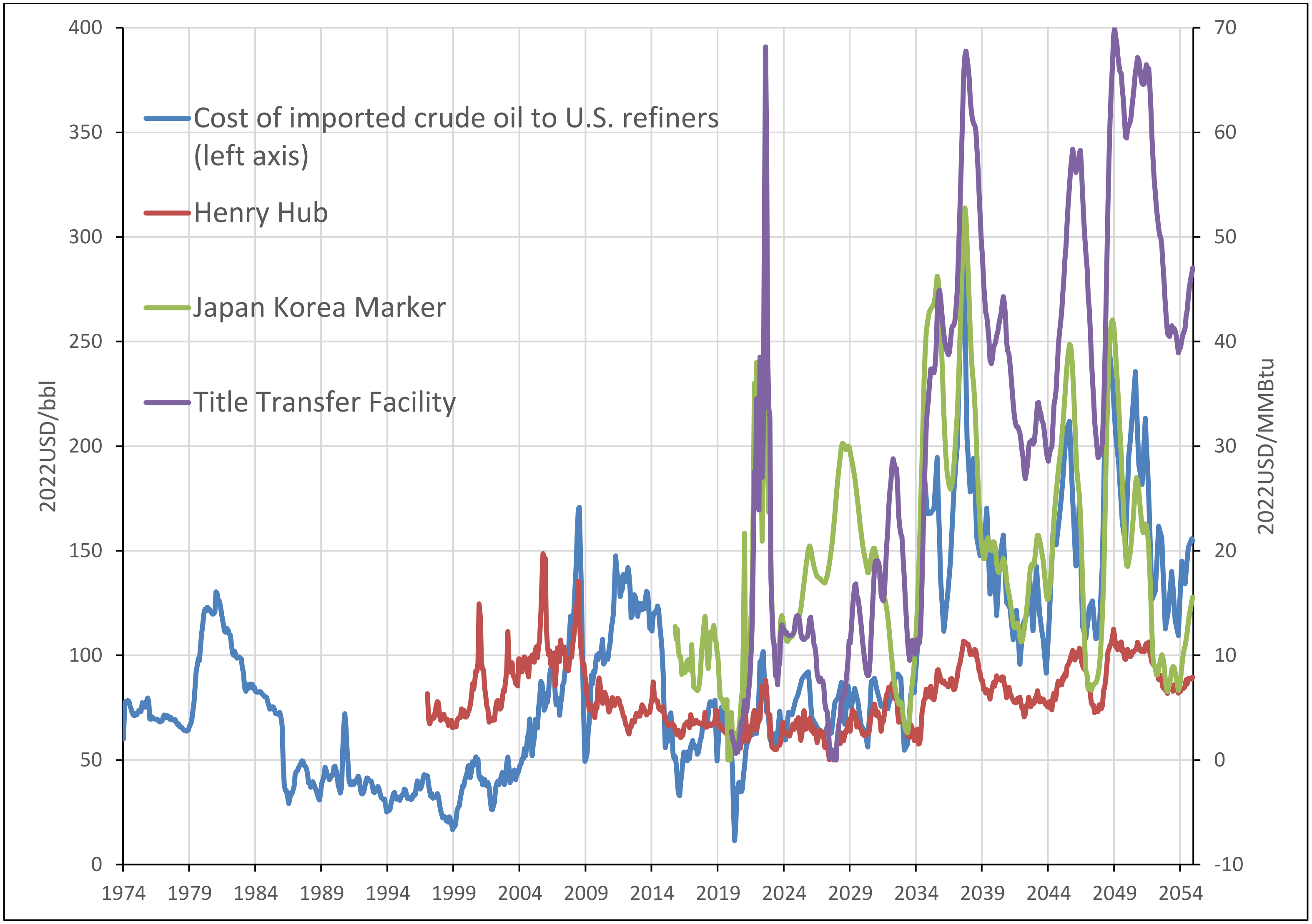
A. Figure **3** shows a long term history and forecast of global benchmark fuel prices. The EIA defines the cost of imported crude oil to U.S. refiners as the "world price". Louisiana's Henry Hub is the thickest market for pipeline gas worldwide. Japan Korea Marker (JKM) is used to represent the price of Asian LNG, and Dutch Title Transfer Facility (TTF) is used to represent the price of LNG in Europe.

Equations for each of the lines shown, along with other equations, such as world demand for crude oil, non-OPEC supply, world GDP, and global greenhouse gas damages, were estimated econometrically. The unexplained components of the main equations in the fuel price modules were used to parameterize normal probability distributions, from which numerous random draws were taken. The random draw most profitable to OPEC, on a present value basis, was selected as the base case, shown in Figure 3. This draw was significantly more profitable to OPEC than any other draw taken, and significantly more profitable than a deterministic forecast, in which the random components were "zeroed out". The reasons why OPEC profits from volatility are explained in the research referenced and the documentation of the forecast, also referenced. To maximize this profitability, shocks to price should come as a surprise to both consumers and non-OPEC producers. According to Saudi Energy Minister Prince Abdulaziz bin Salman,

> We will never leave this market unattended. I want the guys in the trading floors to be as jumpy as possible. I'm going to make sure whoever gambles on this market will be ouching like hell.

Axes in Figure 3 are scaled so that the heights of the oil and gas lines are comparable, assuming each barrel of crude oil contains 5.8 MMBtu of energy. Because of the cost of liquefaction and cold transport, LNG is more expensive than crude oil, before the social cost of emissions is included. Though oil and gas are both substitutes in consumption and complements in production, the substitutability governs the relationship between their prices far more often, so oil price shocks cause shocks to the price of LNG, as in 2022 after the Russian invasion of Ukraine. Europe's LNG import capacity is expanding rapidly, so a recent futures curve for TTF is used as the forecast through October 2025. Despite this, the forecast for TTF is more sensitive to oil shocks than is the forecast for JKM, possibly because TTF's history as the major pricing point for European gas, rather than National Balancing Point in Britain, is short and encompasses the shock associated with the war in Ukraine. The analysis of the Empress contracts does not refer to the forecast for TTF, only to the forecast for JKM, though a forecast for TTF would be germane to evaluation of a contract for LNG delivered to New England.

Figure 3: Long term history and forecast of global benchmark fuel prices



**Q. How would global fuel price shocks affect the value of the Empress contracts in New Hampshire?**

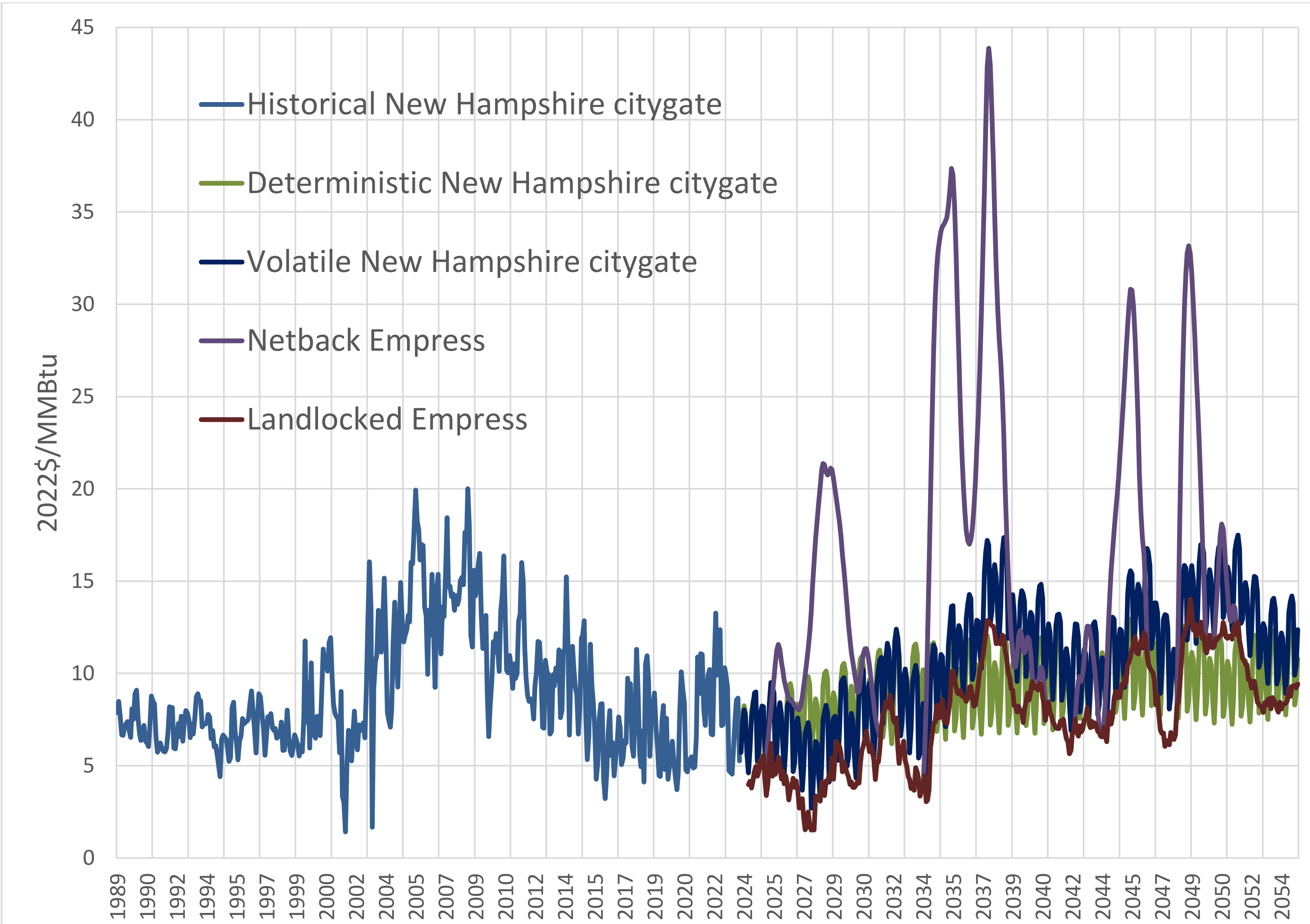
A. Using data to 1997 from the EIA , an equation for the price (USD/MMBtu) of natural gas at the New Hampshire citygate (NHCG), where wholesale gas is delivered to retail distributors, is estimated as a function of the price at Henry Hub and separate deterministic trends for each month, to reflect the changing seasonality of emergent congestion on pipelines entering New England, shown in Table 1.

Table 1: Regression equation estimating New Hampshire citygate price

| | Coefficient | Standard Error |
|---|---|---|
| $H_t$ | 0.391 | 0.056 |
| JanTime | 0.005 | 0.001 |
| FebTime | 0.003 | 0.002 |
| MarTime | -0.001 | 0.001 |
| AprTime | -0.001 | 0.001 |
| MayTime | 0.005 | 0.001 |
| JunTime | 0.009 | 0.002 |
| JulTime | 0.006 | 0.002 |
| AugTime | 0.006 | 0.002 |
| SepTime | 0.004 | 0.001 |
| OctTime | -0.005 | 0.001 |
| NovTime | 0.002 | 0.001 |
| DecTime | 0.006 | 0.002 |
| $NHCG_{t-1}$ | 0.504 | 0.059 |
| $NHCG_{t-2}$ | 0.149 | 0.036 |
| Constant | 0.272 | 0.217 |

Figure 4 shows historical and forecast prices for natural gas at the New Hampshire citygate. The forecast line labeled "volatile New Hampshire citygate" in Figure 4 uses the forecast for Henry Hub shown in Figure 3 in the equation reported in Table 1. It reflects the impacts of global fuel price shocks. The magnitude, long cycles, and seasonality of this forecast

Figure 4: New Hampshire citygate and Empress contract prices; 2022$/MMBtu



echo those of the historical series.

The forecast line labeled “deterministic New Hampshire citygate” in Figure 4 uses a forecast for Henry Hub with the random components “zeroed out”. It does not reflect the impacts of global fuel price shocks, but it extends the long cycle and seasonality of the historical series.

The line labeled “landlocked Empress” equals the price at Henry Hub shown in Figure 3 plus basis from there to Alberta of -1.15 USD/MMBtu in 2023 reported by the Alberta Energy Regulator , plus [redacted], plus 25₵ to account for the markup from delivery points along the Granite pipeline to Northern’s distribution system, making it comparable to the New Hampshire citygate price. This price is consistently below the volatile New Hampshire citygate price, showing the good economics of the Empress contracts highlighted in that exhibit. However, that the basis to Henry Hub is so negative highlights the temporary geographic isolation of the market for natural gas in Alberta.

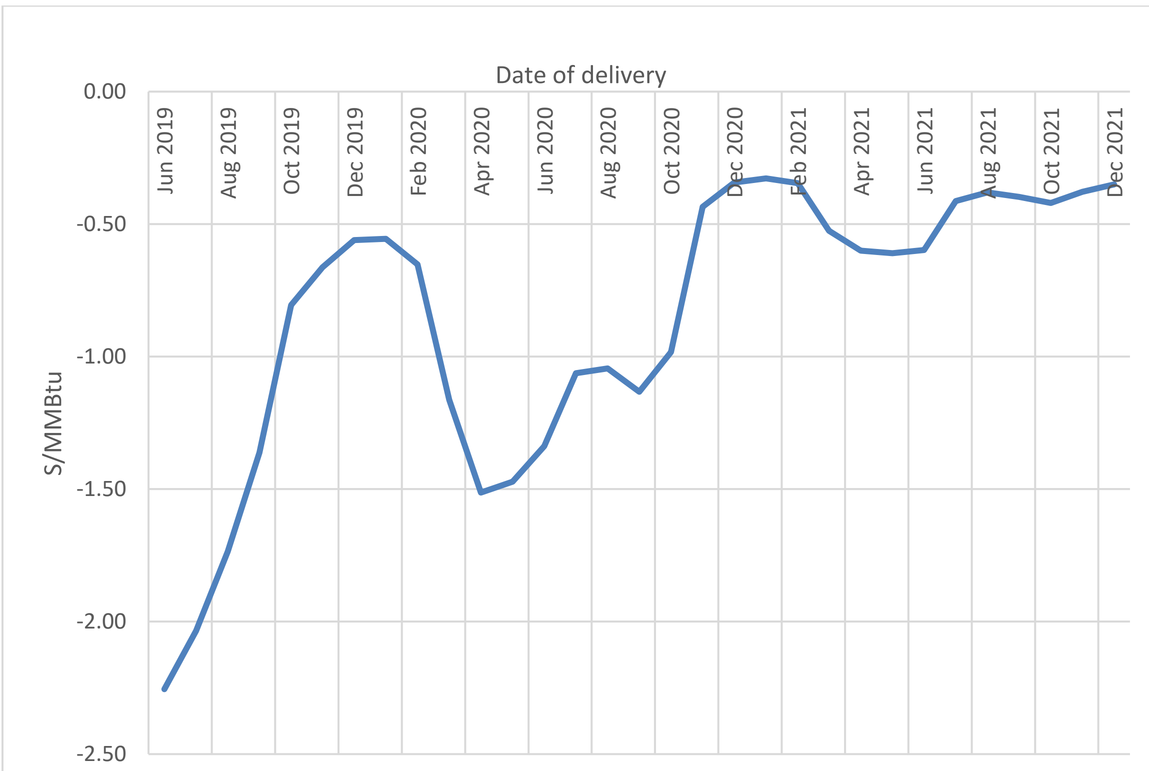
The line labeled “netback Empress” is actually the greater of landlocked Empress and a netback from JKM to Alberta. The netback is the price of JKM from Figure 3 minus the cost of transportation to Asia, the cost of liquefaction, and the cost of pipeline transport from Alberta to the Pacific Coast, plus [redacted], plus 25₵ to account for the markup from delivery points along the Granite pipeline to Northern’s distribution system. The costs of transportation to Asia, liquefaction, and pipeline transportation from Alberta to the Pacific Coast are based on estimates from Zou et. al (2021; Table 2, page 4). The authors report these costs as percentages of the price of regasified LNG, but I fix their real levels calculated at 2021 prices throughout the forecast because LNG prices are volatile, and these components of costs cannot be expected to vary nearly as much. The cost of liquefaction in British Columbia may be lower than along the U.S. Gulf Coast because of lower ambient temperatures in British Columbia.

Netback Empress, though lower than the volatile New Hampshire citygate price line during much of the contract term, far exceeds the New Hampshire price during fuel price shocks. It is for this reason that I recommend that The Commission require Northern to evaluate hedging strategies for commodity price risk long term. To 2054, the end of the contract term, the real levelized (@3% p.a.) New Hampshire citygate price is $10.20/MMBtu, while the levelized landlocked Empress price is $7.23, but the levelized netback Empress price is $14.01. Futures curves typically do not factor in global fuel price shocks in advance, as intended by OPEC, only regular seasonal variation and trends, so hedging that risk by buying futures before OPEC surprises the market, and waiting to buy again until price comes back down, could make the difference between the Empress contracts being an improvement on spot gas in New England, and not. Buying three years in advance, except during upward shocks to price, should suffice: OPEC has not visited a *long* price shock on the market since the price collapse of 1986. Given the duration of the JKM futures strip, this could be done by buying in advance in that market. Those positions, of course, could be resolved close to delivery dates and gas purchased spot.

Long term bilateral contracts are also a possibility, including for delivery in Alberta or for additional LNG in New England. Either could help manage shocks, but perhaps not lower overall price levels for Empress gas, as sellers in Alberta should be expecting higher prices overall once they have better access to the global market for LNG. Again, the first new liquefaction project is expected to come online in 2025, and the last in 2028.

This was the case at Waha. “In 2021, additional pipeline capacity to transport natural gas out of the Permian production region was put in service, and the price differential between Waha Hub and Henry Hub narrowed.”[8] Figure 5 shows the basis future from Waha to Henry Hub in May of 2019. It trended up and stabilized when congestion on outgoing pipelines was going to be relieved by new capacity.

Figure 5: Waha basis future to Henry Hub; May 2019




Source: Intercontinental Exchange; **https://www.theice.com/marketdata/reports/142**

The contango in the futures strip on the Natural Gas Exchange (NGX) in Alberta now roughly matches that at Henry Hub, where prices will be lifted by increasing global demand for

[8] **https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2022/09_08/**, accessed December 13, 2023.

LNG.[9] As markets for natural gas become increasingly linked globally, geographic diversification of spot purchasing points will become a less effective way to manage price risk.

It is also worth noting that gas will be extracted in Alberta where the marginal cost of doing so equals the spot price, and shipped to Asia when spot prices are high enough, displacing coal-fired electric generation there, whether or not Northern locks in the price it pays for Empress gas ahead of time.

**Q. How would the Empress contracts lower the cost of residential electric service?**

A. Though DG 23-087 is a gas docket, residential electric customers have a stake in it: Any reduction in the cost of energy in New England, including both the cost of gas-fired generation and the cost of RGGI allowances, which are passed through to residential electric customers, will help them. Gas continues to be the marginal fuel much of the time for electric generation. Because the Empress contracts fund construction of additional pipeline capacity between the source of gas and New England, they will lower both the LMPs ultimately paid by residential electric customers and the price of retail gas to residential customers. Diversion of gas to electric generation from gas service will mitigate, but not nullify, the downward impact of additional pipeline capacity on the price of retail gas. Through RGGI, residential electric customers pay external costs of emissions of $CO_2$. The effect thereon of the Empress contracts will be incremental, but that is how cost-minimizing choices are made, “at the margin”.

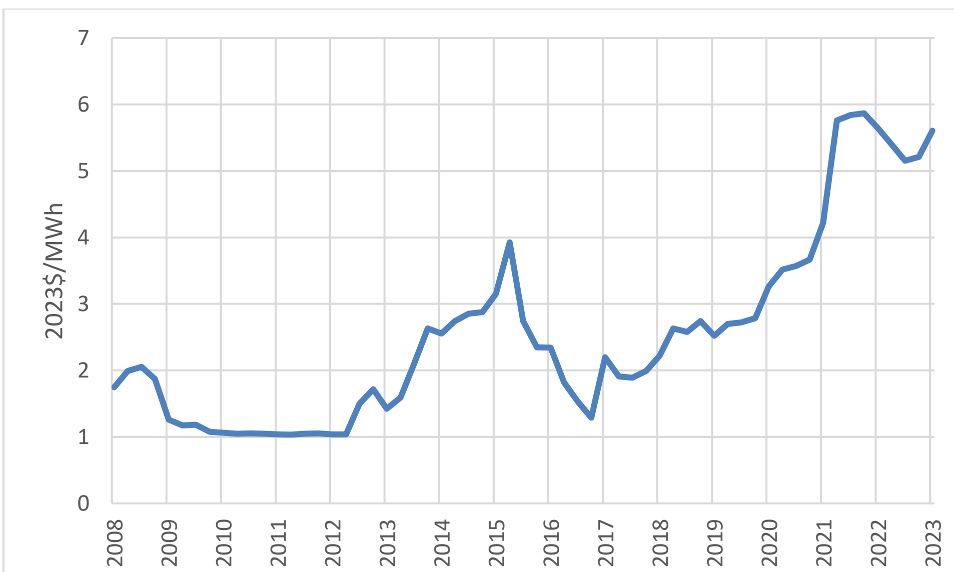
The normal process of decarbonization involves a phase in which natural gas is substituted for coal in the generation of electricity, and most of the reductions in emissions New England has achieved have come through substitution of gas for coal or oil. While this process transpired, it contained the price of RGGI allowances to low levels by lowering the

[9] **https://www.gasalberta.com/gas-market/market-prices**, accessed December 13, 2023.

demand for them, because fewer allowances are required to produce a MWh using gas than coal. This process is not quite complete, and may not be for some time, but substitution of natural gas-fired generation for coal-fired generation from Merrimack Station will lower the price of RGGI allowances in the future. The Empress contracts will bring more natural gas to New England, incrementally lowering the cost of gas-fired generation and extending the substitution of gas for the coal burned at Merrimack Station, lowering the price of RGGI allowances.

The RGGI price has risen considerably in recent years, as shown in Figure 6, assuming 0.058 $tCO_2$/MMBtu for gas and a heat rate of 7.0 MMBtu/MWh.

Figure 6: Real price of RGGI allowances



**Q. Would the Empress contracts and similar arrangements lead to the closure of Merrimack Station?**

A. Not likely. Figure 7 compares the full social operating costs of a combined cycle gas-fired plant and those of Merrimack Station from 2017 to November 15, 2023, assuming the gas fired plant sets the LMP at the Merrimack Station ISO-NE node. The social operating cost of gas equals the LMP, plus estimated greenhouse gas (GHG) damages shown in Table 2, less the RGGI price shown in Figure 6, since the RGGI price is reflected in the LMP and partially covers the GHG damages. The social cost of coal equals the private (internal) operating cost of Merrimack Station plus estimated $CO_2$ damages shown in Table 2.

Figure 7: Real social operating costs of natural gas and coal at Merrimack Station

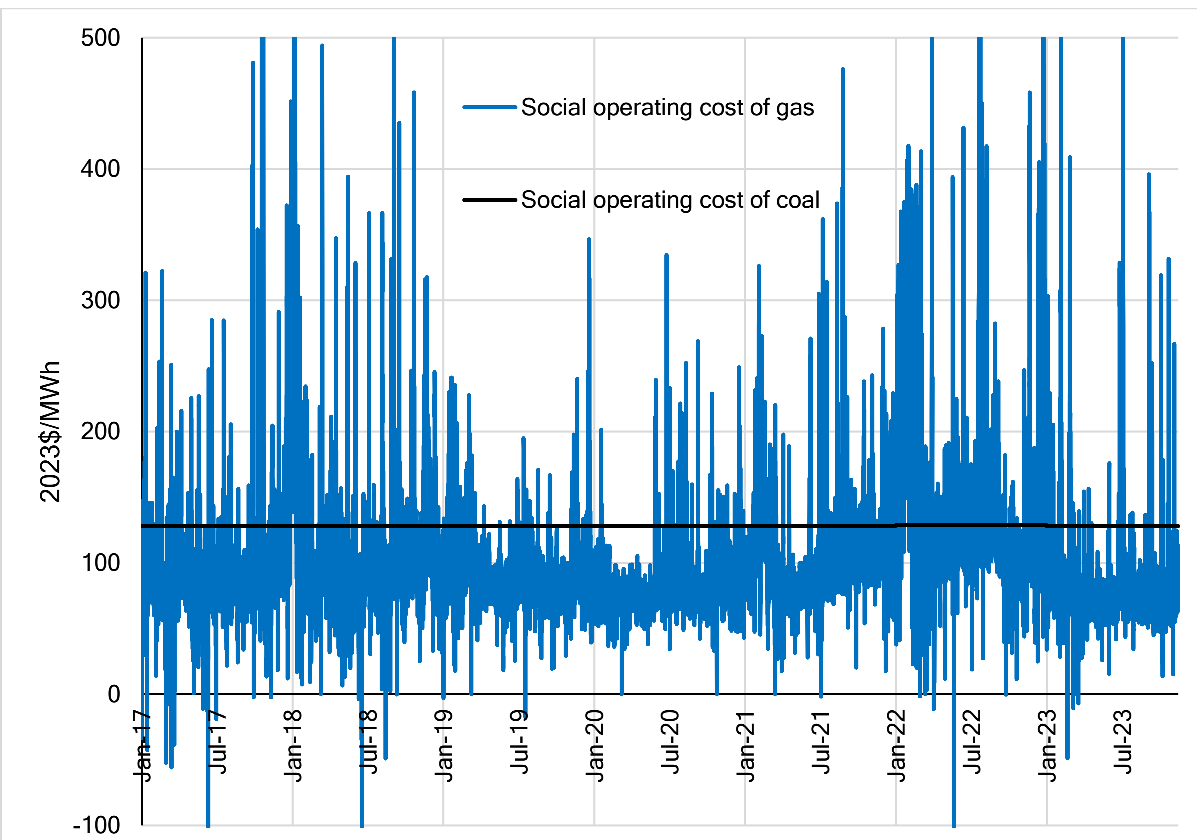


Table 2: Assumptions underlying Figure 7

| | | | |
|---|---|---|---|
| Heat rate of coal | MMBtu/MWh | 10.5 | |
| Units | MMBtu/short ton | 19.333 | |
| Price of coal | $/short ton | | [1] |
| 2017 | | 123.81 | |
| 2018 | | 105.64 | |
| 2019 | | 93.90 | |
| 2020 | | 95.02 | |
| 2021 | | 124.39 | |
| 2022 | | 256.52 | |
| 2023 | | 101.38 | |
| Variable O&M of coal | $/MWh | 4.5 | [2] |
| Minimum up time of coal | Hours | 48 | [3] |
| Emissions of coal | $tCO_2$/MWh | 1.15 | [4] |
| $CO_2$ damages of coal USA | $/$tCO_2$ | 107 | [5] |
| $CO_2$ damages of coal USA | $/MWh | 123.05 | |
| GHG damages of gas USA | $/MMBtu | 6.30 | |
| Heat rate of gas | MMBtu/MWh | 7.0 | |
| GHG damages of natural gas USA | $/MWh | 44.09 | |
| Capacity of Merrimack Station | MW | 482 | |

[1] https://www.eia.gov/coal/data/browser/#/topic/45?agg=0,2,1&rank=g&geo=vvvvvvvvvvvvvo&freq=A&start=2001&end=2022&ctype=map&ltype=pin&rtype=s&maptype=0&rse=0&pin= accessed November 21, 2023

[2] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf accessed November 7, 2023

[3] https://www.nrel.gov/docs/fy12osti/55433.pdf

[4] https://www.eia.gov/tools/faqs/faq.php?id=74&t=11 accessed November 7, 2023

[5] https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3821603 accessed November 7, 2023

It would have been socially optimal to operate Merrimack Station when, and only when, the social operating cost of gas exceeded the social operating cost of coal for any 48 hour period. Socially optimal and actual plant factors are shown in Table 3. They are reasonably close, except in 2018 and, especially, in 2022, when high fuel prices caused by the Russian invasion of Ukraine drove LMPs to very high levels, but Merrimack Station did not respond by operating more. The price of coal rose, but that internal cost is swamped by the external cost of emissions from coal, and that is why variation in full social cost for the plant is hardly visible in Figure 7, though it is present. Consequently, most of the net social benefits of operating Merrimack Station socially optimally shown in the lower section of Table 3 were foregone in 2022.

Table 3: Plant factors and net social benefits of operating Merrimack Station, and FCM prices, 2017-23

| Plant factor of Merrimack Station | | | |
|---|---|---|---|
| | | Socially optimal | Actual |
| 2017 | | 0.07 | 0.06 |
| 2018 | | 0.14 | 0.03 |
| 2019 | | 0.04 | 0.07 |
| 2020 | | 0.01 | 0.03 |
| 2021 | | 0.09 | 0.07 |
| 2022 | | 0.31 | 0.07 |
| 2023 | through August | 0.05 | 0.04 |

| Net social benefits of operating Merrimack Station if run optimally | | | FCA price |
|---|---|---|---|
| | 2023$ | 2023$/kW | 2023$/kW |
| 2017 | 13,391,950 | 27.78 | 3.50 |
| 2018 | 27,038,477 | 56.10 | 17.73 |
| 2019 | 4,177,334 | 8.67 | 8.77 |
| 2020 | 802,435 | 1.66 | 12.18 |
| 2021 | 7,424,695 | 15.40 | 9.08 |
| 2022 | 77,015,802 | 159.78 | 6.94 |

Sources: EIA-923 and EIA-860 Reports; **https://www.eia.gov/electricity/data/eia923/**, accessed November 22, 2023

This is at prices for emissions well in excess of the RGGI price, and even at those higher prices for emissions, it was, or would have been, socially optimal to operate the plant, and the net social benefits per kW of doing so generally exceeded the prices in the forward capacity market for the contemporaneous commitment years. Merrimack Station did not receive a capacity supply obligation in the most recent ISO-NE forward capacity auction (FCA), but it does not need one. Profitable socially, without a capacity obligation, it is much more profitable privately, given the lower RGGI prices. However, given the upward trajectory of the RGGI price, it is possible that it will approach the true social damages during the term of the Empress contracts, to 2054, so I use my estimates of those damages from Table 2 in Figure 7. Even then, it will be socially economic to operate Merrimack Station for some time if the kind of spikes in LMPs shown in Figure 7 persist, especially during fuel price shocks, but those spikes will be smaller if arrangements like the Empress contracts go forward.

When the social cost of gas did exceed that of coal in Figure 7, it was largely when those spikes in LMPs occurred, because of sometimes high prices for natural gas in New Hampshire. In the regression reported in Table 1, 19 percent of the variation in the New Hampshire citygate price was unpredictable variation in basis to Henry Hub, and surely represents congestion premia on pipeline capacity entering New England. The changes predicted by the monthly time trends further include such congestion premia. Whether new pipelines enter from the southwest, like Project Maple, or the north, like the Empress capacity, they will lower these congestion premia, making it less economic, both socially and privately, to operate Merrimack Station, thus lowering LMPs and the price of RGGI allowances that are ultimately paid by residential and other retail customers for electric service.

Looking at the plant factors in Table 3, it is likely that substantially greater incoming pipeline capacity would have rendered it not socially economic to operate Merrimack Station in 2017, 2019, 2020, 2021, and 2023, though it would likely still have been economic to operate it at some, lower, plant factor in 2022, during the global fuel price shock. Arrangements like the Empress contracts may not lead to the shutdown of Merrimack Station, but should lead to its operating less often, emitting less $CO_2$, and lowering the RGGI price ultimately paid by residential and other electric customers.

**Q. What is the OCA's position on the conditions under which The Commission should approve the Empress contracts?**

A. If The Commission is to rule on these contracts, the OCA supports approval. Additional incoming natural gas pipeline capacity is badly needed in New England, and the Empress contracts fund such expansion, at least for a large part of the path between New England and the source of gas. They will not only lower the price of retail gas for Northern's residential customers, but, by reducing congestion on incoming pipelines generally, they will lower the price of natural gas for all residential customers in New Hampshire. Because gas is still the marginal fuel for electric generation, they will lower the cost of commodity for residential electric ratepayers, and, by helping to displace coal-fired generation at Merrimack Station, they will lower the price of RGGI allowances, further lowering residential electric rates.

Our single caveat is that global fuel price shocks will have a larger effect on the price of natural gas in Alberta once new liquefaction facilities are completed in British Columbia, better connecting Alberta to global markets, and The Commission should require Northern to evaluate available hedging strategies, including, but not necessarily limited to, purchasing Japan Korea Marker LNG on the futures market and signing long term contracts for purchase of pipeline gas in Alberta, or additional LNG on the coast in New England.

**Q. Does this conclude your testimony?**

A. Yes.