Case No. 14-238
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STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DE 14-238

Public Service Company of New Hampshire

Determination Regarding PSNH's Generation Assets

TESTIMONY

OF

DEAN M. MURPHY

January 26, 2016

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A. INTRODUCTION AND OVERVIEW

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

A. My name is Dean Murphy. I am a Principal at The Brattle Group, an economic consultancy based in Cambridge, Massachusetts. My business address is 44 Brattle Street, Cambridge, Massachusetts, 02138.

Q. Please summarize your professional background and education.

A. I have over 20 years of experience consulting to electricity clients, including investor-owned and public electric utilities, independent producers and investors, industry groups, system operators, and consumers. The issues I have examined include resource and investment planning (including power and fuel price forecasting), valuation for contract disputes and asset transactions, climate change policy and analysis, competitive industry structure and market behavior, and market rules and mechanics. I have addressed these issues in contexts including business planning and strategy, regulatory hearings and compliance filings, litigation and arbitration. My educational background includes a Ph.D. in Industrial Engineering and Engineering Management from Stanford, and a B.E.S. in Materials Science and Engineering from Johns Hopkins. Additional detail on my background is contained in my resume, attached as Exhibit 1 of this testimony.

Q. What is the purpose of your testimony?

A. I have been asked by Non-Advocate Staff ("Staff") in this proceeding to develop an estimate of the net customer savings that would result from the divestiture of the PSNH generating facilities.

Q. How did you approach this?

A. The approach I have taken to estimating customer savings is to compare generation-based total costs to PSNH customers in the absence of divestiture (the "No Divestiture" case) to the alternative generation-based costs with divestiture (the "Divestiture" case). The difference in total costs between the Divestiture and the No Divestiture cases is the total customer savings resulting from divestiture. In the Divestiture case, the relevant costs are only the securitized stranded costs, since there will be no further costs associated with PSNH's generating plants following divestiture. In the No Divestiture case, the relevant costs include the fixed costs of owning and operating the plants, offset by the net value of the electric power services the plants provide – primarily electric energy and capacity. As explained below, the market cost of serving load is the same in both cases, and thus does not affect customer savings.

Q. Are you measuring customer savings in terms of customer rates, or total costs to customers?

A. For this analysis, I look at the potential impact of divestiture on total generation costs to PSNH customers, as opposed to customer rates.

Q. Are there any limitations created by analyzing total costs rather than rates?

A. My total cost metric cannot address issues of customer migration (and by extension, the sustainability of the current partially-regulated construct under which PSNH owns and operates generation), nor cost allocation across customer classes, both of which can be important and would be addressed by an analysis of generation rates. However, though customer rates may be an important metric for these and other reasons, it is first necessary to understand total costs before rates can be characterized.[1] Further, if it can be shown that total generation costs with Divestiture are expected to be lower than with No Divestiture, such that Divestiture would lead to aggregate customer savings measured in dollars, then the issues of customer migration and cost allocation can be handled separately from the fundamental question of divestiture.

B. CONCEPTUAL APPROACH

Q. Please describe your analysis at a conceptual level.

A. My overall goal was to calculate the sum of the customer cost components after assumed divestiture for both the No Divestiture and Divestiture cases. Conceptually, the customer savings from divestiture are equal to the difference in total customer costs between the Divestiture case and the No Divestiture case. There are several categories and sub-categories of cost in each of these cases, including the market cost of serving load. I take advantage of the structure of this analysis by recognizing that some costs are the same in the Divestiture and No Divestiture cases, and so they do not affect customer savings.

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[1] I assume here that future generation rates will accurately recover total generation costs, at least in expectation, so that generation costs are a reasonable reflection of the total costs that customers will pay in rates.

Q. Can you illustrate the structure of this analysis?

A. Figure 1 offers a conceptual illustration of the structure of the analysis. On the left in the No Divestiture case, the total generation-related costs can be grouped into two broad categories. First, there are the fixed costs of generation. These consist of capital costs, including depreciation and the return on rate base, as well as the fixed operating costs of the plants – the costs that are required to keep the plants operational, and generally do not depend on how much the plant operates. The second broad category is the net cost of providing generation services for load, given that the PSNH generation portfolio is available to operate. In the case of PSNH, this can be further separated conceptually into two components. The first of these is the cost of serving PSNH's total load entirely from the market. The second is the offsetting net revenues that are available from operating the PSNH generation portfolio in the market – primarily capacity and energy revenues, where the energy revenue itself is net of the variable cost of producing the energy. ("Other" costs include generation costs not related to the generation portfolio being divested, such as the potential out-of-market costs of PSNH's Power Purchase Agreements – PPAs.) In all, the costs that customers face in the No Divestiture case are the net costs that result from crediting back the net market revenues of the generating portfolio against the total market cost of serving load, and then adding on the fixed costs of the generation.[2]

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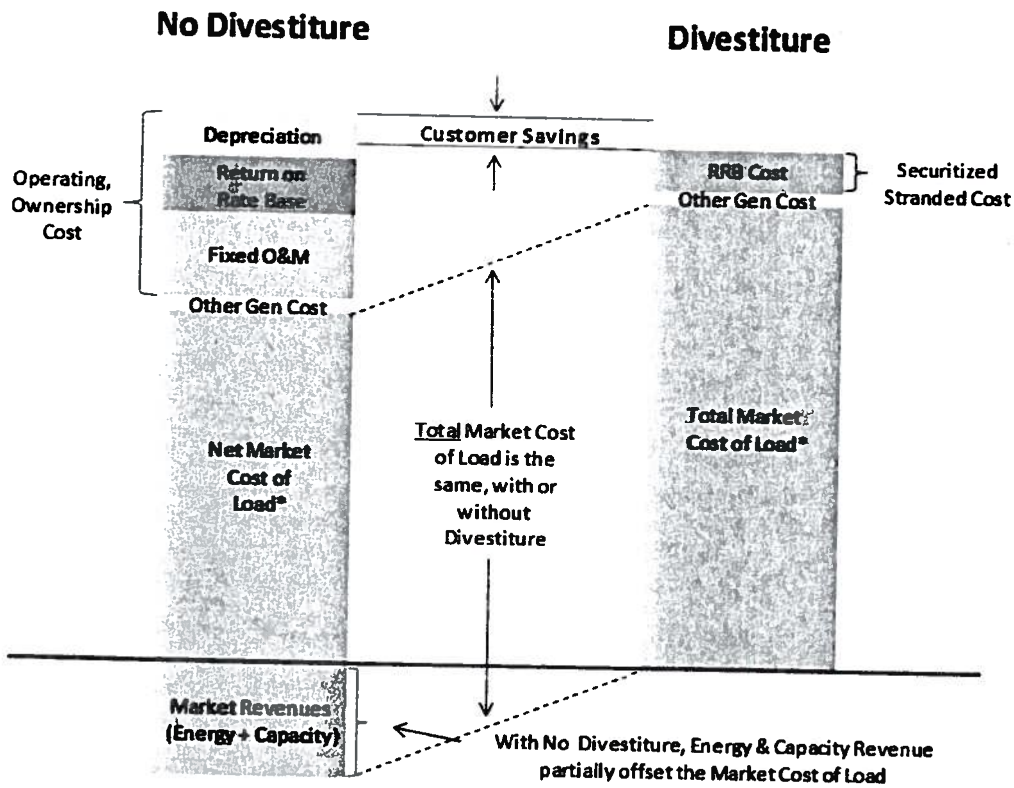
2 This perspective does obscure the distinction between customers who purchase generation from PSNH via its default service, and those who take distribution service only from PSNH and buy power directly from the market (in fact, all costs and benefits of owning the generation are allocated to generation customers). But it nonetheless accurately represents total cost, the basis of this analysis.

Figure 1: Conceptual Structure of Customer Savings Analysis



*Net Market Cost of Load is equal to Total Market Cost of Load minus Market Revenues earned by the plants

Q. What are the corresponding costs in the Divestiture case?

A. With Divestiture, the cost categories are simpler. Customer cost consists of the cost of serving load at market (including the Other costs associated with PPAs that will not be divested; these are the same as in the No Divestiture case), plus the securitized stranded costs, collected via the Rate Reduction Bonds (RRBs). The RRBs represent all remaining securitizable costs related to owning and operating generation, net of the sale proceeds (and including bond issuance costs, etc.), securitized at a low interest rate and recovered over time.

Q. How do the Divestiture and No Divestiture cases compare in this approach?

A. In comparing the two cases, the cost of serving PSNH's load is the same in both, and so it does not affect the difference between them. Thus, in the No Divestiture case, the relevant costs are the fixed costs of the generating portfolio, offset by the portfolio's net revenues in the market. This can be compared to just the securitized stranded cost in the Divestiture case in order to measure the customer savings from divestiture.

C. CALCULATION OF CUSTOMER SAVINGS

Q. How did you implement this conceptual approach in your calculation of customer savings?

A. Of course, in applying this conceptual framework, the costs in each category may (and do) differ from one year to the next, so we can think of having a similarly-structured cost comparison for each year. The resulting annual comparisons can be summarized, for example, as average annual values.

To implement this framework for the No Divestiture case, I requested data from Eversource for a number of the cost categories, which they were able to provide at the aggregate generating portfolio level. Eversource provided Fixed O&M cost estimates that I understand are from current operating budgets, as well as projected payroll and property taxes. Eversource also provided from its own financial projections the annual Depreciation amounts, as well as the components of Rate Base (e.g., net plant, working capital, inventories, prepayments, deferred taxes). The Return on Rate Base is the annual average Rate Base multiplied by the weighted average cost of capital (WACC). The WACC is based on Eversource's current capital structure (54.3% equity), its current long-term debt rate (4.47%), and its allowed after-tax equity return (9.81%), yielding a pre-tax WACC of approximately 11.0%. The costs associated with the deferred recovery of Merrimack Scrubber costs (approximately $123 million as of 1/1/2016) are recovered over 7 years beginning in 2016, and are included as components of Depreciation and Return on Rate Base during those years.

For the customer costs related to serving load at market, I used figures provided in the NHPUC Staff report of April 1, 2014.[3] As noted above, this will not affect customer savings, since the Divestiture case contains the same value for the cost of serving load at market.

Q. Did Eversource also provide projections of the market revenues the plants would capture for capacity and energy?

A. No. I developed projections of the capacity and net energy revenues that would be earned by the plants. Eversource assisted me by providing the plants' operating characteristics, including heat rate, operating levels and variable O&M, and operating constraints such as start costs, minimum runtime and downtime. For capacity revenue, I use the capacity that can be provided by each plant (based on the plants' seasonal claimed capability, the ISO's capacity rating that forms the basis for capacity payments). This was multiplied by the actual

[3] Preliminary Status Report Addressing the Economic Interest of PSNH's Retail Customers as it Relates to the Potential Divestiture of PSNH's Generating Plants, Staff of the New Hampshire Public Utilities Commission, April 1, 2014, in Commission proceeding IR 13-020.

capacity prices from the FCA auctions, for the auctions that have been held to date. The most recent capacity auction, FCA 9, is for the capacity obligation period June 2018 through May 2019. Beyond this, I used a capacity price forecast for ISO-New England markets provided by SNL Financial; this projects that capacity prices will remain generally similar to the FCA 9 price going forward.

Q. Please describe how you projected the net energy revenue of the plants.

A. The net energy revenue that can be earned by the plants will depend on energy market prices, so I began by developing a projection of future power prices. I did this on an hourly basis, using historical hourly prices as a starting point and adjusting for changes in natural gas and carbon prices from the historical period to the future forecast period. I used this approach because in most hours in New England, power prices are set by natural gas plants, and their dispatch costs are influenced primarily by the cost of gas and CO2 emission rights. I then adjusted these prices further as necessary to calibrate them to current forward prices for power.

From here, I grouped the PSNH units into two categories, which I treated differently. The first group contains the hydro and the Schiller biomass units, which I assume will operate as baseload units, accepting the prevailing power price when they generate. These units were modeled as capturing the average power price for the periods when they operate. For Schiller biomass, I deducted the net operating costs (accounting for projected REC value and the existing REC sharing agreement). The hydro units capture the average monthly power price, with their generation output equal to their historical average monthly generation, to reflect their seasonal availability.

Q. How did you treat the second group of units?

A. The second group consists of the fossil (coal, gas and oil) units which are dispatchable, with the ability to produce and sell power during periods where the market price is above their variable operating costs. For this group of units, I performed a virtual dispatch against the projected future hourly power price described above. I account for their operating costs (fuel and CO2 cost, heat rate, variable O&M) and operating constraints (start costs, minimum runtime and downtime, minimum load level, etc.) to simulate the periods when it would actually be profitable for them to run and the net revenues they could earn, if they faced these projected hourly power prices. This allows a realistic characterization of how the plants' value relates to future power prices.

Q. Did you consider any other sources of revenue or expenses for the No Divestiture case?

A. I considered several, but did not include them in the analysis because the other items identified were relatively modest and unlikely to affect the analysis materially. For example, the plants earn a modest amount of revenue from ancillary services, such as providing black start capability to the ISO and for the winter reliability program. Similarly, the FCM pay-for-performance program includes penalties that may be imposed on plants with capacity obligations if they do not provide power in shortage conditions.

Q. How did you determine costs in the Divestiture case?

A. In the Divestiture case, for the securitized stranded costs I relied on the calculation of stranded costs in the original Eversource analysis. This included all remaining securitizable costs related to owning and operating generation, net of the sale proceeds as well as the $25 million foregone recovery of Merrimack scrubber costs that Eversource agreed to in the

Settlement Agreement (and including issuance costs, fees, and tax stabilization payments). The remaining balance is securitized at a low interest rate and the costs are recovered over time via the RRBs. This analysis incorporates the $225 million estimate of sale proceeds provided in the March 31, 2014 La Capra valuation report, though I also developed the capability to analyze the effect of a different sale price.[4] Finally, for the customer costs related to serving load at market, I used the value from the April 1, 2014 NHPUC Staff report; again, since the No Divestiture case contains this same value, it does not affect customer savings.

D. CUSTOMER SAVINGS RESULTS

Q. Can you illustrate your results?

A. Figure 2 below summarizes the results of my analysis, showing the annual average costs over the first 5 years after assumed divestiture, 2017-2021, organized according to the cost categories discussed above. The year by year results are provided in tabular form in Exhibit 2. In the No Divestiture case, the aggregate fixed costs (Depreciation, Return on Rate Base, and Fixed O&M) average $213 million per year; this is offset by capacity and net energy revenues averaging $132 million per year, for a net cost (including the customer costs related to serving load at market) of $634 million per year. This should be compared with the Divestiture case, in which the RRB costs and the customer costs related to serving load at

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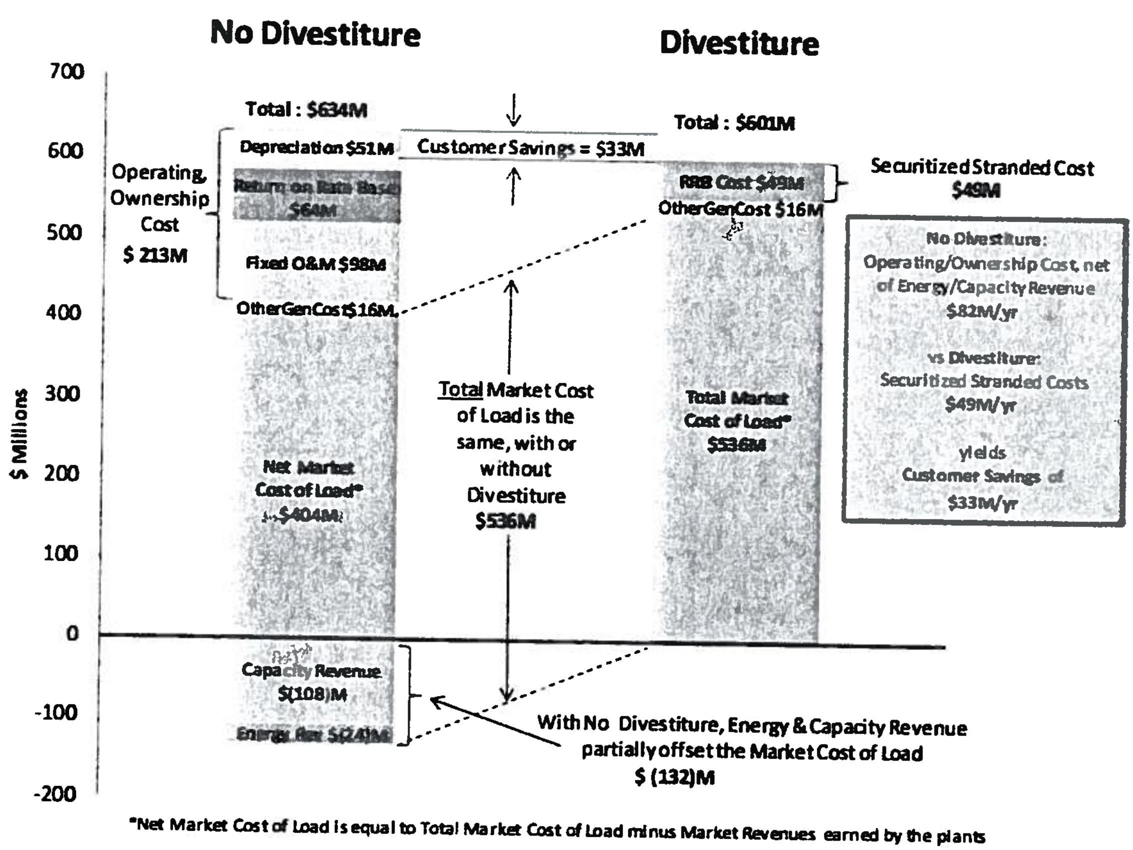
[4] PSNH Generation Asset and PPA Valuation Report, La Capra Associates, March 31, 2014.

market average a total of $601 million per year. The difference of $33 million per year between the No Divestiture and Divestiture costs is the average annual estimated customer savings during the first five years.

Figure 2: Average Annual Customer Savings from Divestiture, 2017-2021



Q. How confident can you be in this estimate of customer savings?

A. This approach has some significant advantages in that it removes from the equation some large uncertainties that do not actually affect the customer savings, because they are the same in both the No Divestiture and Divestiture cases. But of course, as with all estimates and forecasts. there is some uncertainty involved.

Q. What are some of the primary uncertainties?

A. The different categories of inputs are associated with different levels of uncertainty. In the No Divestiture case, the fixed costs of owning the plants – the Depreciation, Return on Rate Base, and Fixed O&M costs – are inputs from Eversource. Although I have not attempted to validate these, there is good historical evidence on operating costs, and reasonable predictability in Depreciation and Rate Base since they are based in substantial part on the accounting treatment of known past costs. This means that these are not likely to be a major source of uncertainty in the result.

The market revenues available to the plants may be somewhat more uncertain, as markets can be difficult to predict. Capacity revenues have already been determined through the first few years of the horizon (through May 2019). Beyond that, capacity prices could differ from the projection, though since prices are already approaching the ISO's Net CONE value (the theoretical equilibrium capacity price), the remaining uncertainty may be relatively limited.

Q. Do the net energy revenues also contain uncertainty?

A. Net energy revenues, though they are projected to be smaller than capacity revenues, may be more uncertain in total, particularly for the fossil plants. These have high operating costs, and thus depend on relatively infrequent and brief periods of high prices for their revenue. There can be significant uncertainty about the actual magnitude and duration of prices when they approach such high levels, even if there is reasonable confidence in the average or typical price level. This means that there can be significant uncertainty in the fossil plants' net energy revenues, related to future energy prices.

Q. What uncertainties affect the Divestiture case?

A. Once the plants are divested and stranded costs are securitized, there is no further uncertainty in the level of securitized stranded costs.[5] But until the plants are divested, there is significant uncertainty about the sale proceeds they would command at auction. The original Eversource analysis assumed the plants would sell for $225 million, the value estimated by the La Capra valuation study of March 31, 2014. Market conditions may differ by the time of the divestiture, and with them, the likely sale proceeds. Even beyond that, there is uncertainty about what the plants would command at auction because these are unique assets in a specific market at a particular time, with only limited direct evidence relevant to their likely sale value. The sale price may depend on how many and which bidders participate, their bidding strategies, the structure of the auction, etc. Although I am not prepared to speculate about the likely sale price of the plants, I can assess the sensitivity of the RRB costs to the sale price. Each additional $100 million of sale price will decrease RRB costs and increase customer savings by $9.2 million per year, averaged over the first 5 years.

Intuitively, if high market prices for power make the plants worth more to keep, then they should also be worth more to sell, which would at least partially offset the effect on customer savings. However, this logic holds only if future prices are accurately foreseen at the time of the divestiture. If the plants are sold based on an expectation of moderate future power

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[5] There will still be the uncertainty of market prices if the plants are divested, which could yield greater uncertainty overall since there is no longer the hedge of owned generation to offset potentially high future power prices.

prices, but events unfold later so that prices are actually high, those ultimately high prices would not be reflected in the plants' sale price. Alternatively, if high future prices are expected but do not materialize, customers might get the benefit of a high sale price to reduce RRB costs if the plants were divested, but would not benefit from high revenues absent divestiture.

E. CONCLUSION

Q. What level of customer savings did you find, and what is the source of these savings?

A. Under current market expectations, divestiture is likely to result in customer savings averaging about $33 million per year over the first 5 years. One of the primary sources of savings from divestiture is the lower interest rate customers will pay on the securitized stranded costs, relative to the cost of capital they currently pay on the capital investment in the plants. However, divesting the plants will also eliminate the natural hedge they provide for customers, creating greater exposure to market prices.

Q: Ultimately, how confident can you be about this level of customer savings?

A: The level of confidence differs for each of the components of the savings calculation, and each component contributes some level of uncertainty in the ultimate result. The fixed costs of owning the plants – Fixed Operating costs, Depreciation and Return on Rate Base – should by their nature be relatively straightforward to project with reasonable confidence. The primary uncertainties regard future conditions in the regional power markets, particularly the energy market, and the sale price of the plants. All else equal, if future power markets exhibit high prices that give the plants high value, then retaining the plants would reduce customer costs, which reduces the customer savings from divestiture. If future market prices for power are low, the plants' value would be lower, and savings from divestiture would be higher.

The second major uncertainty is the sale price of the plants, which may partly offset the market price uncertainties, though this is not necessarily the case. To the extent future power market conditions are foreseen at the time of divestiture, and if the anticipated value of the plants is reflected in their sale price, then future market conditions will push the sale value in the same direction as the plants' operational value, and these will partially offset in the customer savings calculation. However, if future market conditions are not foreseen, or if the anticipated value is not reflected in the auction price, then these uncertainties may not offset one another.

Q. Does this conclude your testimony?

A. Yes, it does.

DEAN M. MURPHY
Principal

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Dr. Dean Murphy is an economist with a background in engineering. He has expertise in energy economics, competitive and regulatory economics and finance, as well as quantitative modeling and risk analysis. His work centers on the electric industry, encompassing issues such as resource and investment planning (including power and fuel price forecasting), valuation for contract disputes and asset transactions, climate change policy and analysis, competitive industry structure and market behavior, and market rules and mechanics. He has addressed these issues in the context of business planning and strategy, regulatory hearings and compliance filings, litigation and arbitration. Dr. Murphy has examined these matters from the perspectives of investor-owned and public electric utilities, independent producers and investors, industry groups, regulators, system operators, and consumers.

Dr. Murphy holds a Ph.D. in Industrial Engineering and Engineering Management and an M.S. in Engineering-Economic Systems, both from Stanford University, and a B.E.S. in Materials Science and Engineering from the Johns Hopkins University. Prior to joining The Brattle Group in 1995, Dr. Murphy worked as an associate with Applied Decision Analysis, Inc.

AREAS OF EXPERTISE

- Resource Planning, Investment, and Forecasting
- Valuation for Energy Contract Disputes and Energy Asset Transactions
- Climate Policy Analysis
- Market Structure and Competitiveness
- Electricity Markets: Energy, Capacity, and Ancillary Services
- Procurement and Restructuring

EXPERIENCE

Resource Planning, Investment, and Forecasting

- For Manitoba Hydro, which is evaluating large investments in hydroelectric capacity and transmission expansion that would facilitate significant off-system sales, Dr. Murphy testified in a public hearing regarding the potential evolution of long-term power prices in the export market. He also developed a set of future scenarios based on the possible future evolution of several key market drivers, and forecast long-term market prices of power for each scenario.

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The scenario drivers included fuel prices, climate policy, coal plant retirements, renewable energy portfolio standards, and load levels, which are affected by changes in power prices and active demand management programs. This assignment has been repeated in subsequent years to understand how changing market drivers have influenced the potential range future of power prices.

- Dr. Murphy assisted the investor-owned utilities and regulators in Connecticut in complying with a legislative mandate to develop annual resource and procurement plans for the state, over several annual cycles. He focused particularly on the development of a set of scenarios against which alternative resource plans were evaluated, in order to illuminate the risks that might be associated with such plans. Key issues were potential federal climate legislation, natural gas prices, electricity demand, and demand side management strategies, as well as the complex interplay between these factors. He also evaluated energy security issues, including interactions between natural gas availability and electric reliability, as well as the potential role of nuclear power and emerging technologies, and their impacts on energy security.
- For a consortium in the initial stages of developing a major long-distance offshore DC transmission link designed to integrate multiple thousands of megawatts of new wind generation into several electric markets, Dr. Murphy performed a preliminary evaluation of the potential energy and capacity value of the project, and the approximate customer cost impact. These analyses were designed to assist in securing FERC approval for incentive rate treatment and abandoned cost recovery.
- For a merchant electric generator contemplating renewing or replacing an expiring output contract for a gas-fired generator, Dr. Murphy used a power market simulation model to forecast potential long-term power price trends under several scenarios involving fuel costs, generator retirements and renewable additions. Using the forecasts of potential long-term trends, he simulated the plant's short-term operations and its resulting financial performance. A key factor that had a significant effect on the plant's value in this analysis was characterizing the short-term volatility of power prices and the plant's ability to respond to capture short periods of attractive prices.
- Dr. Murphy developed a long-term forecast of Renewable Energy Credit (REC) prices across multiple states and interconnected electricity markets for a renewable generation developer. He considered state-level Renewable Portfolio Standard (RPS) requirements over time, as well as potential federal renewable requirements, looking at the cost and geographic availability of several potential renewable resource types and incorporating the effect of in-state requirements and alternative compliance payments.
- Dr. Murphy worked with a manufacturer of an energy storage technology to estimate its value on several dimensions across a range of potential applications. He used simulated charge-discharge cycles with historical prices in several markets to demonstrate not only the technology's energy and capacity value, but also its potential ancillary service and reliability benefits.

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- For the Tennessee Valley Authority (TVA), Dr. Murphy assisted in the development of TVA's long-range Strategic Plan to deal with the development of competitive markets and a changing regulatory environment. He organized and performed numerous operational and financial analyses to understand TVA's performance under a wide variety of scenarios, and integrated the results into a strategic framework, considering numerous potential outside influences (e.g., fuel price scenarios) and TVA responses (e.g., product unbundling or changes to TVA's pricing structure).
- For a utility client interested in building a merchant transmission line, Dr. Murphy evaluated the benefits of the line, designed and implemented an auction for the rights to use the line once constructed, and evaluated the bids received in the auction.
- For an entrepreneurial client investigating the opportunities for an electric storage technology in the deregulated electric market, Dr. Murphy developed a model that optimizes facility operations with respect to a set of forecasted electric commodity price profiles. The model was used to evaluate the technology's potential profitability on several different electricity systems. Commodity price profiles for each system were projected by integrating historical real-time system marginal cost data with the projected cost of additional capacity.

Valuation for Energy Contract Disputes and Energy Asset Transactions

- In a bankruptcy hearing, Dr. Murphy testified regarding the fair market value of the post-petition energy services (electricity, chilled and hot water) provided under contract by a creditor, in order to determine the debtor's responsibility for these costs.
- Dr. Murphy assisted the Staff of a state public utility commission in understanding the customer cost savings associated with a proposed utility divestiture of generating assets, as assessed by the utility. Key issues were whether the utility's analysis had correctly represented the operational benefits of the assets to customers in reducing their energy costs, and whether the capacity value of the assets had been accurately captured.
- Dr. Murphy assisted an Asian energy company in deepening their understanding of U.S. electricity and natural gas markets, as part of their plan to acquire assets in the region. Brattle helped to characterize market rules, including recent and proposed changes, in several regional ISOs, and how these rules may affect the financial opportunities of generators located in these ISOs.
- In a major arbitration dispute, Dr. Murphy assisted a merchant generating company in determining the value lost when the government agency with whom it had contracted to develop a gas-fired power plant decided to terminate the contract before the plant was completed. A key contributor to the value lost was the potential riskiness of the contract revenues. The contract's unusual structure insulated the merchant generating company from many of the risks normally associated with electricity markets, transferring these risks to the government agency over the contract's twenty-year term. This transfer of risk had a major effect on the value of the contract and thus on the magnitude of the arbitration claim.

- Dr. Murphy calculated the damages that resulted from several partial derates of a nuclear plant. The plant's owner had a unit-contingent output contract with a regional utility, and during the derate events, the plant delivered less power than it would have if it had operated normally. The utility had to replace the missing power (or equivalently, in some hours lost the opportunity to resell the power) at higher market prices, and also lost some of the capacity value of the plant in the regional capacity market.
- For an investor exploring the acquisition of several gas-fired generators in markets without retail deregulation, Dr. Murphy helped to analyze the potential profitability of the assets under a range of assumptions about future natural gas and CO_2 allowance prices. Building on simulation results developed by another consultant, Dr. Murphy and the Brattle team were able to investigate several factors specific to the individual assets in question but not captured by a broad market simulation model.
- Dr. Murphy advised a committee of bondholders of a foreign subsidiary of a U.S. merchant power company that was undergoing restructuring. He advised regarding the value of several power contracts and assets in which the subsidiary had an interest, including a potential damage claim for a terminated long-term contract.
- In a dispute related to a terminated long-term power contract for an electric generating facility, the original contract contained clauses that may be triggered in the event of a default, based on the value of available replacement opportunities. For a group of bondholders of the facility, Dr. Murphy prepared an affidavit regarding the market value of the available replacement opportunities, and how they related to the facility's debt and operating costs.
- For an independent power producer, Dr. Murphy supported expert testimony to value damages due to termination of a long-term electric generator tolling contract, requiring power market forecasting and finance valuation techniques. Key to this case was the increase in risk caused by the loss of the contract, in an environment (following the collapse of the power sector in 2001) in which it was not possible to obtain a long-term replacement contract.
- For a bondholder of a power marketing company, Dr. Murphy evaluated the likely outcome of an arbitration hearing regarding damages due as a result of the termination of a long-term generation contract.
- For an independent power producer forced into bankruptcy by the rejection of a long-term power contract by its counterparty, Dr. Murphy assessed the economic damages due to the loss of the contract.
- In the context of a dispute over damages in a terminated gas supply contract, Dr. Murphy analyzed and provided written testimony regarding the potential to resell contracted natural gas that could not be utilized by the purchaser.

- For a utility client attempting to acquire a partially completed generating station to be held as a utility affiliate, Dr. Murphy analyzed the acquisition and affiliate transaction to determine whether there would be any violation of market power regulations.

Climate Policy Analysis

- Dr. Murphy helped the senior executives of a major coal producer to assess the long-term implications of U.S. climate policy on the electricity generating infrastructure. He characterized the effects of different potential policy structures and stringency on CO_2 prices, the economics of existing and future electric generating technologies, and likely generation expansion and retirement decisions over several decades, in order to forecast power sector costs and CO_2 emissions under these policy approaches. The project also involved estimating the long-term effects on CO_2 emissions in the transportation and other sectors.
- In seeking regulatory approval for a generation expansion plan, an investor-owned utility engaged Dr. Murphy to help understand the interrelationship between potential climate policy, the cost of natural gas, and the cost of generation technologies. He helped the client to incorporate these interacting factors into the client's existing planning models.
- Dr. Murphy assisted the executives of a major U.S. electric company in developing a proposed policy structure to mitigate greenhouse gas emissions (carbon dioxide) that would be economically efficient, effective, and manageable for industries and the economy. The research evaluated the impact on the electric industry, addressing overall, regional, and company-level effects of alternative policies and stringency of legislation. It also addressed the effects on consumers and other industries.

Market Structure and Competitiveness

- Dr. Murphy leads the Brattle team as the Independent Auction Monitor for the Southern Companies' Energy Auction, which has been in operation since April 2009. The auction is governed by FERC tariff, which is designed to mitigate prospective market power. The tariff requires Southern to administer day-ahead and hour-ahead auctions for "Into SoCo" products, and to offer its available capacity at a cost-based rate into these auctions. The Brattle team developed data structures, monitoring protocols and automated tools to track Southern Companies' load forecasting, purchases and sales, outage declarations, and unit capabilities and costs in order to monitor their cost-based offers into each auction in compliance with the FERC tariff. Brattle also ensures that the auction functions and clears properly. Monitoring is done on a daily basis, with reports annually on auction performance and tariff compliance to the FERC.
- Dr. Murphy participated in a market power analysis in the context of a major electric utility merger, focusing on the analysis of how transmission availability and constraints affect the potential for the exercise of market power. He coordinated the collection and interpretation of transmission data from numerous utilities. To correct for the inherent data weaknesses, he

designed and oversaw a separate, integrated transmission modeling effort to determine the ability of the grid to support short-term power transactions.

- Dr. Murphy evaluated the potential anti-competitive effects of a merger between a major regional natural gas company and an electric utility in a region where electric generation is highly dependent on natural gas as a fuel. He examined the potential for the merged company to exercise vertical market power by manipulating the price of natural gas to influence the competitive price of electricity, and what effect that would have on the competitiveness of the electric market.
- In several other cases, Dr. Murphy analyzed whether proposed energy company mergers or acquisitions would create the potential for the exercise of horizontal and/or vertical market power, developing mitigation strategies where appropriate.
- In a proposed merger involving an East Coast electric utility, Dr. Murphy assisted senior management in evaluating the effects of retail access on the financial health of both the client company and the potential merger partner, taking into account projected operating costs, the timing of open access, market prices for power, customer loss, and stranded cost recovery.

Electricity Markets: Energy, Capacity, and Ancillary Services

- For a competitive energy supplier and generation owner, Dr. Murphy analyzed the role of demand-side resources, such as interruptible load, in an ISO-sponsored capacity market. He examined the extent to which demand-side resources could supply capacity needs, and the risk that frequent utilization of such resources might dissuade their participation in the market.
- Dr. Murphy assisted a U.S. electric ISO with understanding the implications of expanding ISO membership on the ancillary service requirements of both existing and proposed new ISO members.
- For a major hydroelectric generator, Dr. Murphy assessed the planning and decision system used to determine when and how to allocate energy (e.g., in spot or forward markets). Both value and risk implications are important, and both are affected by large uncertainties and correlations in forward and spot prices, weather, energy (water) availability, and non-electric restrictions, among other factors. Dr. Murphy developed a number of recommendations for improving the accuracy of the utility's forecasts and models, thus improving the decisions based on them.
- Dr. Murphy assisted a major Northwest hydroelectric generator in understanding the role of electric ancillary services, including voltage control and reserve generating capacity, in a restructured electric market. Issues included the interaction between the energy market and the ancillary services market, and the implications of embedded cost pricing as compared to competitive market-based pricing of ancillary services. This engagement involved

coordinating work across the generation and transmission groups within the client organization to determine appropriate tariff rates for these ancillary services.

- In a series of projects for the Electric Power Research Institute (EPRI), Dr. Murphy examined the potential for hydroelectric generators to provide reserve generating capacity in a restructured electricity market. Dr. Murphy developed an economic framework for understanding how the markets for electric energy and reserve capacity interact, and whether hydro's technical advantages in providing reserve capacity are likely to make reserves a natural niche market for hydro. Dr. Murphy also evaluated the probable effect of industry restructuring on the value of hydroelectric power assets, taking account of their technical capabilities to store and release energy according to market conditions, and provide ancillary services.
- For a utility client, Dr. Murphy evaluated the effects of pricing structure on demand for electricity, load shape, and revenues. Changes in pricing structure can stimulate electric demand, increasing revenue without increasing the per unit electricity price. This may be a useful mechanism for mitigating a utility's stranded costs as the industry is restructured.

Procurement and Restructuring

- Dr. Murphy assisted an electric utility client with regulatory strategy regarding a state proposal to allow utilities to earn a "premium" on long-term power purchases, in order to account for the risks involved in committing to purchased power contracts.
- Dr. Murphy assisted a California utility in hearings before the California Public Utilities Commission regarding the establishment of a process for the California utilities to resume power procurement in the wake of the western power crisis of 2000-2001.
- In several engagements, Dr. Murphy assisted utility clients facing potential customer loss through municipalization. As part of these analyses, he determined the stranded costs (unrecovered investment) that municipalization would involve.
- Dr. Murphy assisted an electric utility client in planning for industry restructuring by characterizing alternative paths that restructuring could take, and developing potential strategies that respond to a competitive market and regulatory changes. He developed a detailed spreadsheet-based system and financial model to evaluate the effects of various strategies and scenarios on the magnitude of stranded costs and the client's financial performance. This modeling effort required analysis and forecasting of the changes in the structure of the market for electricity, as well as probable regulatory changes and their implications. The model served as the basis for several follow-up studies addressing more specific decisions and issues, performed by the client and by The Brattle Group.

Other Engagements

- In eight different litigation cases involving 14 nuclear reactors at 11 plants, Dr. Murphy has evaluated the Department of Energy's (DOE) failure to honor its commitment to remove spent nuclear fuel from U.S. nuclear plants. He led the analytical effort in all of these cases, and provided expert witness testimony in one of them, to characterize how the government should and would have carried out its contractual obligation. Dr. Murphy simulated a nationwide market for the exchange of spent fuel removal rights, as was enabled by the contract, which made it possible to determine the timing of spent fuel removal from each individual plant in the non-breach world. The results of these analyses were used to support the damage claims of the client nuclear owners for ongoing spent fuel storage costs that would have been unnecessary if the DOE had performed its contract obligations.

- Dr. Murphy assisted in a review of the auction of an ownership share in a nuclear generating plant, in order to determine whether the sale was performed using commercially reasonable means to ensure mitigation of the regulated seller's stranded costs.

PUBLICATIONS AND PRESENTATIONS

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DEAN M. MURPHY

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"Transmission Management in the Deregulated Electric Industry: A Case Study on Reactive Power," with Frank Graves and Judy Chang, *The Electricity Journal*, October 2003.

"Price-Responsive Electric Demand: A National Priority," with Peter Fox-Penner, presented at the EPRI International Energy Pricing Conference, Washington, DC, July 26, 2000.

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"Competitive Markets for Reserve Services," presented at the 1999 National Hydropower Association Annual Conference, Washington, DC, March 1999.

"The FERC, Stranded Cost Recovery, and Municipalization," with Peter Fox-Penner, Gregory Basheda, Darrell Chodorow, Jason Hicks, Eric Hirst, James Mitchell, and Joseph Wharton. *Energy Law Journal*, Vol. 19 (1998): 351-386.

"Ancillary Services in the Restructured Electric Industry," presented at the EUC Conference on Reliability and Competition, Denver, CO, November 1998.

"Mechanisms for Evaluating the Role of Hydroelectric Generation in Ancillary Service Markets," (with others), for the Electric Power Research Institute, TR-111707, November 1998.

"The Future of Hydro Resources under Deregulation," presented at HydroVision '98, Reno, NV, July 1998.

"Electricity Price Volatility and Implications," presented at the Electric Power Research Institute Conference on Technology Directions, Business Opportunities and Success Strategies, San Francisco, CA, December 1997.

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"Utility Capital Budgeting Notebook," (with others), for the Electric Power Research Institute, TR-104369, Palo Alto, California, July 1994.

TESTIMONY

Oral testimony before the United States Bankruptcy Court, District of New Jersey, on behalf of Revel AC, Inc., Debtor (Case No: 14-22654-CMB) regarding the fair market value of energy services received from creditor ACR Energy Partners, December 4, 2014. Expert report October 22, 2014.

Before the Public Utilities Board of Manitoba, in the Needs For and Alternatives To Review (NFAT) of Manitoba Hydro's Preferred Development Plan: provided oral testimony regarding future energy prices and price drivers in Manitoba Hydro's U.S. export market in MISO, March 2014.

Deposition, Central Vermont Public Service Corporation and Green Mountain Power Corporation, Plaintiffs, vs. Entergy Nuclear Vermont Yankee, LLC, Defendant. Docket No. 2:12-cv-10-wks, United States District Court, Vermont, April 2013. Expert report February 14, 2013; revised June 5, 2013. Case settled before trial.

Oral testimony before the United States Court of Federal Claims, on behalf of Wolf Creek Operating Company, (Case No. 04-99C), regarding the removal of spent nuclear fuel, March 2010. Expert report September 15, 2009.

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Expert report before the United States Bankruptcy Court, Southern District of New York, on behalf of Contrarian Funds, LLC (Case No. 01-16034), regarding economic damages due to the termination of a natural gas supply contract, August 19, 2005. Case settled before trial.

Exhibit 2: Calculation of Customer Savings from Divestiture, 2017-2026 ($millions)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
No Divestiture										
PPA (Above Market)	16	16	16	16	16	16	16	17	17	17
Return on Rate Base	69	67	65	62	59	57	56	55	54	54
Depreciation	53	53	53	54	44	43	26	27	27	28
Fixed O&M	96	102	101	92	99	101	104	107	109	112
Net Energy Revenues	(29)	(24)	(23)	(23)	(22)	(23)	(23)	(23)	(24)	(25)
Capacity Revenues	(61)	(108)	(124)	(120)	(126)	(130)	(132)	(135)	(137)	(137)
Market Cost of Load*	490	518	514	573	585	612	639	668	698	730
Total Costs	634	623	603	654	655	677	687	715	745	778
Divestiture										
PPA (Above Market)	16	16	16	16	16	16	16	17	17	17
RRBs	53	51	49	46	45	44	43	42	41	40
Market Cost of Load*	490	518	514	573	585	612	639	668	698	730
Total Costs	559	585	579	636	647	672	699	728	757	787
Customer Savings										
Annual Savings	75	38	24	18	8	5	-12	-12	-12	-10
5-yr Annual Average Savings (2017 - 2021)			32.7							
10-yr Annual Average Savings (2017 - 2026)			12.2							

*Market Cost of Load is an assumed value, taken from the original Eversource analysis, that is used to illustrate market costs. It is not necessarily consistent with any particular view of the market, but since it is the same in the No Divestiture and Divestiture cases, it does not affect the Customer Savings calculations.