STATE OF MASSACHUSETTS

BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

Petition of National Grid for approval of	**)**	
long-term contracts to purchase wind	**)**	**Docket No. 10-54**
power and renewable energy certificates,	**)**	
pursuant to St. 2008, c. 169, § 83 and 220	**)**	
C.M.R. § 17.00 et seq.	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE NATURAL RESOURCES DEFENSE COUNCIL,

CONSERVATION LAW FOUNDATION, UNION OF CONCERNED SCIENTISTS

AND CLEAN POWER NOW

Resource Insight, Inc.

JULY 30, 2010

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two U.S. Federal agencies. This testimony has included the review of many utility-proposed power plants and purchased-power contracts.

Q: Have you testified previously before the Department?

A: Yes. I have testified in approximately 46 dockets before the Department, from the proposed Pilgrim 2 nuclear power plant in 1978 to National Grid's 2009 rate proceeding.

II. Introduction

Q: On whose behalf are you testifying?

A: I was engaged by the Natural Resources Defense Council to provide testimony sponsored by NRDC, the Conservation Law Foundation, the Union of Concerned Scientists, and Clean Power Now.

Q: What is the purpose of your testimony?

A: My clients have asked me to comment on a number of issues related to the statutory standards for the Department's review of proposed long-term contracts between Massachusetts investor-owned electric utilities and renewable energy projects, which includes the contracts between National Grid (NGrid) and Cape Wind. Specifically, my testimony discusses the following issues:

- The effects of price-taking renewable-energy projects on prices for electricity and gas. This is the major topic in my testimony.
- The need for a purchased-power agreement to facilitate financing of Cape Wind.
- The effect of Cape Wind on electric reliability in Massachusetts.
- The effect of Cape Wind on electric system peak loads
- The effectiveness of the proposed contracts as price hedges and to increase the predictability of retail prices.

Q: Please summarize your conclusions.

A: Cape Wind is likely to have significant benefits to energy consumers due to its effect on market prices. I estimate that the annual market-price benefits to Massachusetts electricity and gas consumers could be on the order of $150 million annually, at least in the early years of the project's operation. These benefits could be twice the above-market cost of the purchased-power agreement, as estimated by NGrid in its Exhibit MNM-2.

III. Price Suppression

Q: For what products would you expect the addition of Cape Wind to reduce market prices?

A: Cape Wind or similar projects would tend to reduce market prices paid by consumers for the following four market products:

- electric energy,
- electric capacity,
- renewable energy credits (RECs),

- natural gas.

A. Electric Energy Prices

Q: How are electric energy prices set in New England?

A: The New England Independent System Operator (ISO-NE) determines the wholesale price of electric energy in each hour for each of eight zones: West-Central Massachusetts (WCMA), Southeast Massachusetts (SEMA), Northeast Massachusetts (NEMA), and one zone for each of the five other New England states. Each generation owner in New England offers one or more blocks of power at varying prices per MWh; generators in neighboring regions can also bid into New England. While the actual price-setting process is somewhat more complicated, at the simplest level the price in each hour is set at the cost of the most expensive offer necessary to meet demand. If adequate transmission is available, the eight zonal prices differ only by the differences in transmission losses from generation to the transmission delivery points in the various zones. If transmission is constrained, more expensive generation must be dispatched in some zones, and zonal prices can diverge further.

Q: How would the addition of a project like Cape Wind reduce market energy prices?

A: The addition of generation with low bid prices will tend to shift the supply curve, avoiding the need to dispatch the most expensive resources and resulting in lower-bid resources at the margin—and setting the price—in more hours.

Q: Is it appropriate to reflect the reduction of energy prices due to the addition of renewable generation?

A: Yes. In computing the effects of Cape Wind (or any other project) on Massachusetts ratepayers, the Department should count all the quantifiable costs and benefits, whether those flow through the contract or otherwise affect consumer bills.

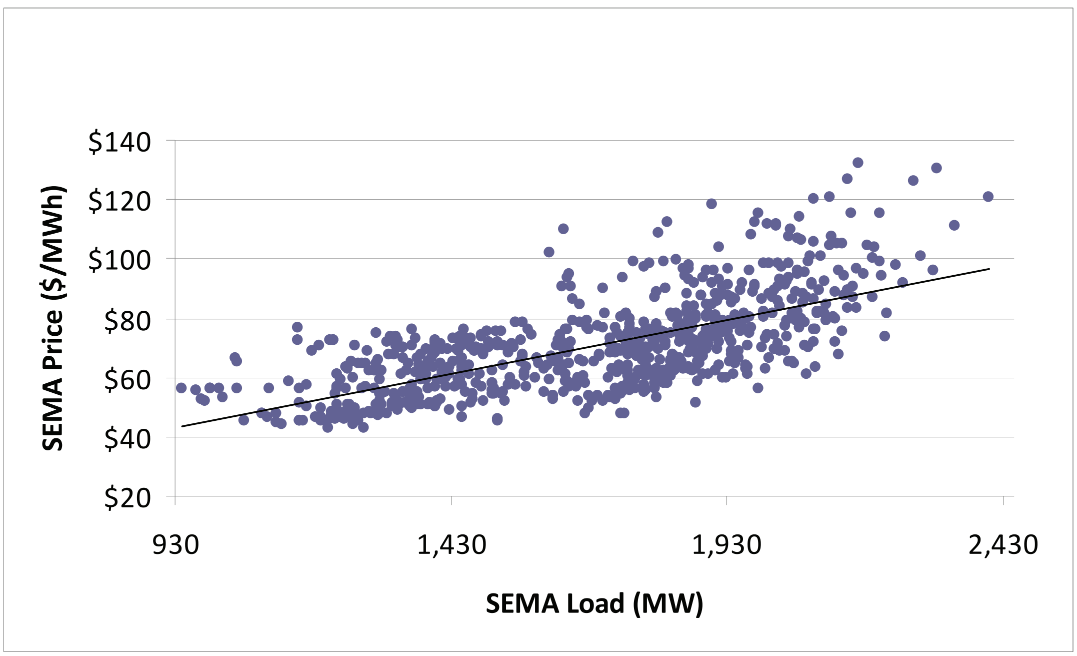
As I understand the economic analyses performed for NGrid, the estimate of the net cost of the Cape Wind contract is reduced by the price suppression caused by Cape Wind. In terms of projecting the net cost of the contract as it will flow through NGrid's cost-recovery mechanisms, that treatment is appropriate and sufficient. Measuring the *total* effect on ratepayers, however, requires that the price-suppression effect of the plant be reflected in both the projection of the contract accounting and the costs of all other power purchased by consumers.

Q: Please provide an example of how Cape Wind would reduce market energy prices.

A: For example, if without Cape Wind the price in a particular hour would have been set by 50 MW of generation from a peaking unit, at $90/MWh, and Cape Wind generates at 100 MW in that hour, the peaker would not be necessary and the hourly price would be set by the next less-expensive resource bid, which might be at $87/MWh. In that hour, Cape Wind would have reduced the price of energy by $3/MWh. If New England energy load in the hour were 16,000 MW, the market value of the energy consumed in that hour would be $48,000 less with Cape Wind than without. Were all energy purchased in the spot market, consumers would save that $48,000; Massachusetts's 45% share of that saving would be about $22,000, or $220/MWh of Cape Wind generation. That benefit would be in addition to the value of the energy to the customers of NGrid or any other utilities purchasing power from Cape Wind under long-term PPAs.[1]

The relationship between load and market energy price is clear from historical data. Since the price in any zone varies with load in that zone and other zones (and perhaps even in neighboring regions), as well as power-plant availability, it would be difficult to account for all the variability in prices, let alone display it visually. The strength of the relationship is shown in Figure 1, for the hourly SEMA loads and prices in January 2009, along with the linear trend line.

Figure 1: SEMA Load and Energy Price, January 2009



Q: You provided a hypothetical example of Cape Wind's effect on market energy prices for one hour. How do you expect Cape Wind would affect prices over the course of the year?

[1]The price effect in this example would not be unusual, especially in the peak period.

A: The price effect varies with the overall price of energy and between peak and off-peak periods. For the 2009 regional avoided-cost analysis, I performed a detailed analysis of the effects of load on market prices.[2] Adding a megawatt of generation that is bid in at zero price (or any price consistently below the market price) has essentially the same effect on price as reducing load by one megawatt. The basic form of this historical analysis was a regression of day-ahead hourly zonal price in dollars per MWh against both day-ahead load in the zone and day-ahead load in the rest of the ISO control area (rest of pool, or ROP).[3] The vast majority of energy in New England is settled in the day-ahead market.

I performed these analyses separately for on- and off-peak hours. To minimize the effect of variation in fuel prices, I took the following steps:

- analyzing each month separately (since fuel prices change less within a month than over longer periods);
- using data from December 2005 through April 2009, covering both high- and low-priced period;
- normalizing the load coefficients for each of the 29 months by dividing the regression results by the average Hub price for the month; and
- averaging the normalized monthly DRIPE coefficient over the three or four years of regressions.

[2]The analysis is presented as “Regional Electric-Energy-Supply Prices Avoided by Energy-Efficiency and Demand-Response Programs,” Chapter 6 of “Avoided Energy Supply Costs in New England: 2009 Report” (2009; Westfield, Mass.: Avoided-Energy-Supply-Component Study Group).

[3]If one of the resulting coefficients was implausible, the zonal price was regressed based on total pool load and the resulting coefficient was then used for both the own-zone and ROP load.

Table 1 summarizes the results of that analysis for SEMA's own-load coefficients, showing the average percentage reduction in the SEMA price for each MW reduction in load or increase in low-bid generation in SEMA.

Table 1: Reduction in SEMA Market Energy Prices per MWh Relief in SEMA

	Peak	Off-Peak
Jan 2006-09	0.0315%	0.0264%
Feb 2006-09	0.0277%	0.0050%
Mar 2006-09	0.0251%	0.0416%
Apr 2006-09	0.0053%	0.0182%
May 2006-08	0.0291%	0.0187%
Jun 2006-08	0.0145%	0.0347%
Jul 2006-08	0.0169%	0.0122%
Aug 2006-08	0.0455%	0.0154%
Sep 2006-08	0.0109%	0.0145%
Oct 2006-08	0.0196%	0.0119%
Nov 2006-08	0.0146%	0.0536%
Dec 2005-08	0.0203%	0.0337%
Winter (Oct–May)	0.0217%	0.0261%
Summer (Jun–Sept)	0.0219%	0.0192%

Table 2 summarizes the results for the rest-of-pool coefficient in each of the other zones, showing the average percentage reduction in that zone's price for each MW reduction in load or increase in low-bid generation in SEMA. Adding a MW of low-bid resource to SEMA reduces prices in other zones by about 0.007% to 0.009%, roughly a third to a half of the effect of the same resource on SEMA prices. My analysis did not attempt to sort out the differential effect on prices in WCMA and NEMA of resources in SEMA versus other states. A change in supply in SEMA probably has a greater effect on the rest of Massachusetts than a similar supply change in other states, especially in Maine (which frequently cannot export all available economic power supply to the rest of New England) and in Connecticut (which frequently cannot import all available economic power supply and thus must run higher local generation). As a result, I have probably underestimated the effect of Cape Wind on prices in other parts of Massachusetts.

Table 2: Reduction in Other Zone Market Energy Prices per MWh Relief in SEMA

	Maine	N.H.	Vt.	Conn.	R.I.	NEMA	WCMA
Peak Period							
Jan 06-09	0.010%	0.009%	0.012%	0.013%	0.008%	0.009%	0.010%
Feb 06-09	0.009%	0.009%	0.011%	0.011%	0.010%	0.010%	0.011%
Mar 06-09	0.010%	0.009%	0.011%	0.007%	0.009%	0.005%	0.011%
Apr 06-09	0.004%	0.004%	0.005%	0.007%	0.004%	0.004%	0.004%
May 06-08	0.003%	0.003%	0.006%	0.010%	0.003%	0.003%	0.004%
Jun 06-08	0.005%	0.006%	0.009%	0.012%	0.007%	0.006%	0.007%
Jul 06-08	0.010%	0.009%	0.012%	0.011%	0.011%	0.007%	0.011%
Aug 06-08	0.008%	0.008%	0.011%	0.011%	0.009%	0.008%	0.011%
Sep 06-08	0.006%	0.007%	0.007%	0.011%	0.007%	0.006%	0.008%
Oct 06-08	0.006%	0.007%	0.007%	0.009%	0.007%	0.007%	0.007%
Nov 06-08	0.008%	0.007%	0.009%	0.008%	0.007%	0.005%	0.009%
Dec 05-08	0.007%	0.008%	0.010%	0.008%	0.008%	0.009%	0.010%
Winter	0.007%	0.008%	0.009%	0.011%	0.009%	0.007%	0.009%
Summer	0.007%	0.007%	0.009%	0.009%	0.007%	0.007%	0.008%
Off-Peak Period							
Jan 06-09	0.011%	0.009%	0.012%	0.006%	0.011%	0.004%	0.012%
Feb 06-09	0.004%	0.004%	0.005%	0.006%	0.004%	0.003%	0.004%
Mar 06-09	0.003%	0.004%	0.006%	0.008%	0.003%	0.005%	0.005%
Apr 06-09	0.006%	0.006%	0.009%	0.010%	0.007%	0.003%	0.008%
May 06-08	0.009%	0.006%	0.010%	0.009%	0.010%	0.005%	0.009%
Jun 06-08	0.008%	0.008%	0.009%	0.011%	0.008%	0.006%	0.009%
Jul 06-08	0.005%	0.007%	0.007%	0.010%	0.007%	0.002%	0.007%
Aug 06-08	0.008%	0.009%	0.009%	0.011%	0.009%	0.009%	0.009%
Sep 06-08	0.008%	0.008%	0.009%	0.008%	0.007%	0.005%	0.009%
Oct 06-08	0.010%	0.010%	0.011%	0.012%	0.008%	0.011%	0.011%
Nov 06-08	0.012%	0.010%	0.013%	0.012%	0.008%	0.012%	0.009%
Dec 05-08	0.009%	0.009%	0.011%	0.009%	0.011%	0.011%	0.011%
Winter	0.007%	0.008%	0.009%	0.010%	0.007%	0.005%	0.009%
Summer	0.008%	0.007%	0.010%	0.009%	0.008%	0.007%	0.009%

Q: Has the Department accepted the recognition of these price effects in resource planning?

A: For the purpose of computing the value of energy efficiency, the Department has adopted the DRIPE estimates from the 2009 regional avoided costs, on which my estimates of the price effects of Cape Wind are based (DPU 08-50-A, pp. 38–39; DPU 09-116 through DPU 09-120).

Q: How large are these effects?

A: The effect of a single megawatt on the price per MWh is very small. At a price of $66/MWh (the average on-peak forward price for 2014), an own-load coefficient of 0.022% would imply a price reduction of 1.5¢/MWh in SEMA and an ROP coefficient of 0.008% would imply a price reduction of 0.5¢/MWh in the rest of the pool.

For the projected average output of Cape Wind, about 174 MW, the effect would be proportionately larger, about $2.50/MWh in SEMA and $0.90/MWh in the rest of New England. Those are significant changes in market prices. For the 2014 off-peak forward price ($52/MWh), the price reductions would be about $2/MWh and in SEMA and $0.70/MWh in the rest of New England.

Another way of looking at the effect is to multiply the price change by the amount of load for which prices are reduced. Were all the energy in New England purchased on the spot market, the price effect for 2014 would resemble the results in Table 3; bills would be lower by about $76 million in Massachusetts and another $59 million in the rest of New England.[4] Customer bills in Massachusetts would be reduced by about $50 per MWh of

[4]These results are generally consistent with the early-year estimates sponsored by Cape Wind Witness Robert Stoddard (e.g., in Figure 3 of Exhibit CW-RBS-3). As I noted above, my estimate of benefits in WCMA and NEMA is probably understated.

Cape Wind generation; customers bills in the rest of New England would be reduced about $40 per MWh of Cape Wind generation.

Table 3: Potential Effect of Cape Wind on Regional Energy Bills, 2014

	2014 GWh[a]	Percent of Energy On-Peak[b]	Price Reduction On-Peak	Price Reduction Off-Peak	Total Price Effect[c]
SEMA	17,285	53%	$2.50	$2.00	$39 M
NEMA+WCMA	45,795	51%	$0.90	$0.70	$37 M
ROP	72,980	53%	$0.90	$0.70	$59 M
Total					$135 M

Notes:
[a]From ISO-NE 2010 Forecast Data File, sheet 2.
[b]Computed from ISO-NE load data for 2009
[c]2014 Growth × Percent Energy On-Peak × Price Reduction On-Peak + (2014 Growth − Percent Energy On-Peak) × Price Reduction Off-Peak ÷ 1000

Q: How do your estimates of energy-price suppression compare to those sponsored by NGrid?

A: My estimates of the price effects are about 30% less than those sponsored by NGrid Witness Madison Milhous, Jr., in Exhibit NG-MNM-6, Table 1. The agreement between our estimates is remarkably close, considering that my analysis is based on historical data from 2005 through 2009, while the NGrid analysis uses production-cost modeling for future fuel prices, capacity and transmission.

There are reasons to expect that the price-suppression effect will be greater in the future than in the historical period on which I relied, and hence closer to NGrid's estimates. For example, as gas prices have fallen relative to oil prices, the jump in prices from gas-fired to oil-fired peakers, and hence the slope of the price curve, will tend to be steeper now than it was in most of my data period. As another example, planned increases in transmission into Connecticut would raise market prices in Massachusetts at high-load hours and increase the slope of the price curve, as more power is diverted from Massachusetts to Connecticut.

My approach to estimating the energy price-suppression effect has the advantage of being derived from historical data, but it does not take into account changes in conditions over time. I view my results as providing a reality check on NGrid's estimates and confirming their reasonableness.

Q: Is all energy purchased in the day-ahead spot market?

A: No. Most New England consumers purchase power under contracts, either directly with suppliers or through their utility or other energy aggregator.

Q: So would the change in prices in the spot market flow through to consumers?

A: Yes, for the most part. Most of the supply contracts are for no more than three years into the future. For Massachusetts Basic Service, the utilities purchase power for one-year blocks, a few months in advance. Those purchases reflect forward market prices, which in turn are based on market expectations of day-ahead spot prices. Once it is clear that a new resource (such as Cape Wind) will come on line, forward prices (and hence generation contracts) will start to reflect the effect of that resource. After the resource enters service and starts reducing spot market energy prices, future prices should fully reflect the resource's contribution to the supply-demand balance.

Q: Are there situations in which the changes do not flow through to consumers?

A: Yes. Vermont did not restructure generation ownership and most of Vermont's energy is supplied by plants owned by the utilities or (to a much larger extent) purchased under long-term contracts. With the end of the contracts with Vermont Yankee in 2012 (and perhaps Vermont Yankee's retirement, due to the Vermont Legislature's decision not to allow renewal of its certificate of public good), Vermont customers may be served much more from short-term purchases or the utilities may enter into new intermediate or long-term purchases.[5] Similarly, Public Service of New Hampshire still owns much of its own generation; roughly half of PSNH's power supply is from short-term purchases.

Within Massachusetts and other restructured states, municipal utilities remain vertically integrated, owning generation or purchasing power long-term for their customers. About 10% of Massachusetts sales are by municipals. The effect of Cape Wind on prices paid by municipal customers will vary with the amount of power the municipal chooses to purchase short-term and with the expiration date of longer-term contracts.

Some restructured investor-owned utilities still have legacy contracts from independent power producers; some have also purchased small amounts of energy under long-term contracts, including the peaker contracts in Connecticut and contracts for renewables and other clean power (e.g., NGrid's proposal in this docket, NStar's two existing and three proposed land-based wind contracts, the comparable purchases to be undertaken by Western Massachusetts Electric and Fitchburg G&E, and the Project 150 renewables and fuel cells in Connecticut).

Q: How much of the potential energy-market benefit of Cape Wind is likely to flow through to Massachusetts energy consumers?

A: That depends on the exact amount of legacy energy contracts, the amount of renewable energy under contract to the IOUs, the amount of short-term

[5] By short term, I mean purchases up to about three years in duration.

energy purchased by the municipal utilities, the timing of expiration of existing long-term purchases by municipals, and the amount of power under short-term contracts negotiated before the market reflects the likelihood of Cape Wind's operation. Overall, it seems likely that Massachusetts consumer market-price benefits will be on the order of $60 to $70 million in 2014.

Q: Would those benefits continue throughout the life of the Cape Wind project?

A: Probably not at the same level as in the early years. The addition of Cape Wind (or any other major renewable resource) would tend to result in some response by the New England electric supply system. For example, the lower market prices resulting from Cape Wind's operation might accelerate retirement or mothballing of existing generation during the period of excess supply in New England, and delay construction of new generation when new generation is required. To the extent that less of these other resources are available, energy prices will tend to be higher, offsetting the direct price-suppression effect of Cape Wind operation.

Q: How could Cape Wind result in the accelerated retirement of existing generation?

A: In principal, the owner of each generator should annually determine whether the going-forward cost of the unit (O&M, fuel, property taxes, any required capital investments) exceeds the market value of the generator (energy, capacity, reserves, and any other ancillary services) over the foreseeable future. If the unit does not appear to be profitable in the coming year or under any reasonable future period, the owner should shut the unit down, temporarily or permanently.

The most-vulnerable units should be those facing large investments for refurbishment or to meet environmental requirements and those with large fixed operating costs but limited energy revenue. It is difficult to anticipate which units may suffer major mechanical problems and require major refurbishment to continue operating. The largest environmental investments are likely at the coal plants; so far, most New England coal-plant owners have been making the investments necessary to keep them in operation.[6] The units with high fixed costs and low energy revenue are mostly the old oil- and gas-fired boiler plants, especially those only capable of burning oil. To date, three oil-only plants (Salem 4 and Wyman 1 and 2) have requested permission to delist, but the ISO has required all three to remain available for local reliability.[7]

Q: Is the operation of Cape Wind likely to result in the shutdown of existing generation?

A: That is difficult to predict, given the limited information available regarding the costs of strategies of the owners of those older plants. The oil plants do not produce much energy, and hence are probably not very vulnerable to changes in energy prices. The coal plants produce more energy and are more sensitive to energy prices than the oil-fired plants, but the long-term viability

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[6]The exceptions are Somerset 6, which has shut down, and Salem 1–3, which requested permission to delist from the 2012–13 forward-capacity auction. Salem 1 and 2 were allowed to delist; Salem 3 and the Salem 4 oil unit were required to stay on line for local area reliability.

[7]It is not clear whether the owners of Salem and Wyman really wanted to shut down these units or were using the threat of shutting them to secure a higher capacity payment from the ISO. The latter strategy seems to have been employed by NRG in requesting to delist Norwalk Harbor 1 and 2 in the 2010–2011 capacity auction. In the 2011–2012 auction, additional capacity eliminated the local capacity requirement, and NRG did not delist Norwalk Harbor, even though the forward capacity price was lower than in 2010–2011 auction.

of the coal plants is much more sensitive to gas prices and environmental regulation than to the price effects of Cape Wind.

If Cape Wind does not contribute to the shutdown of much old generation, it would continue to back down a mix of fuels (mostly gas and coal) for many years, with both the environmental benefit of avoiding burning those fuels and the market-price benefit of reducing the market-clearing price. If Cape Wind does result in the shutdown of oil-fired and especially coal-fired plants, the environmental benefit would be still larger, while the market-price benefit would be smaller.

Q: How could Cape Wind lead to the delay of new conventional generation?

A: If power plants, such as combustion turbines and combined-cycle plants, would be built in response to high energy and capacity prices, and the operation of Cape Wind reduces those prices, the conventional plants would tend to be delayed. By reducing energy prices, Cape Wind may also result in the construction of peaking combustion turbines rather than combined-cycle units.

Q: Are these effects likely in the near term?

A: No. Existing and committed resources, along with the renewables added to the system in response to state renewable-portfolio standards, seem likely to cover the region's capacity need well into the 2020s. Need for new generation would be accelerated by the retirement of Vermont Yankee and various fossil units (to the extent those occur), and delayed by construction of renewables and the success of energy-efficiency programs in Massachusetts and other states.

The only conventional central generation capacity likely to be added in New England in this decade are the peaking units that Connecticut utilities have under contract to mitigate the shortage of forward reserve capacity, and possibly a couple of municipally owned generators. The Connecticut peakers are committed (the four Devon units came on line this summer, and the Middletown units are under construction). Their economics are not very sensitive to changes in energy prices, and the utilities are committed to pay for the plants regardless of energy prices. MMWEC plans to add the 280-MW combined-cycle Unit 3 to the Stony Brook plant in 2014 and the Taunton Municipal Lighting Plant plans to complete the 250-MW combined-cycle Unit 10 at the Cleary plant by 2015.[8] It is possible—but far from certain—that small price reductions would discourage the municipal utilities from pursuing these plants.

Q: What is your assessment of the likely duration of the energy price effects of Cape Wind?

A: While there are many uncertainties, the energy price effects are likely to remain close to the initial level through at least 2020, and then fade out over the five to ten years after that. My expectations for this phase-out are similar to those of Energy Security Analysis, Inc. (Exhibit CW-MNM-6, Figure 2).

B. Electric Capacity Prices

Q: How are electric capacity prices set in New England?

A: The ISO has established a system of forward-capacity auctions (FCAs), starting with an auction in February 2008 for the 2010–2011 capacity year, gradually transitioning to auctions three years prior to capacity year. So far,

[8]Due to their lower cost of capital, municipal utilities have been building a disproportionate share of non-renewable generation, including Braintree's Watson CTs, CMEEC's Pierce CT and various diesels, and the Vermont Public Power Supply Authority's Swanton CTs.

three FCAs have been completed, and a fourth (for 2013–2014) will be held this August.

The basic concept of the forward-capacity market (FCM) is that resources will bid the price they require to remain available (or become available, for new resources) and the ISO will select the lowest-cost resources that are sufficient to meet the ISO's reliability target. If new capacity is needed, the clearing price for capacity should be great enough to pay for construction of new conventional peaking capacity.

Q: Has the FCM operated as intended?

A: No. From the beginning of the FCM, the resources offered have been much larger than the amount required, resulting in the market clearing at declining floor prices established for the first three auctions. Faced with the prospect of the capacity price falling still further, the ISO changed the rules so that the floor would continue for the next three auctions (2013–14 through 2015–16) at the $2.95/kW-month of load set in the third FCA. The ISO may change the FCA rules in other ways, to limit the ability of new resources supported by municipal utilities and long-term contracts to depress the forward capacity price for new resources. The latest ISO proposal would continue to reduce the price for most capacity to reflect the actual bid price of those contract resources, while pricing a small amount of capacity as if the contract resources had bid much higher prices.

Q: Under the rules for the next three auctions, could Cape Wind reduce the ISO-NE capacity price to consumers?

A: Yes, if enough capacity is withdrawn from the auction (retired, mothballed, sold out of the region, or just priced above $2.95/kW-month) to push the clearing price above the $2.95/kW-month floor. That outcome would require some change in status for about 4,000 MW of resources. In that situation, the capacity provided by Cape Wind would help push the capacity price back towards or even to the $2.95/kW-month floor.

Q: When the capacity market is no longer in surplus at the ISO floor price, or the floor is removed, how much might Cape Wind affect the forward capacity price?

A: The auction results in the third FCA show that, for prices less than about $4/kW-month, each megawatt of additional capacity bid into the auction below the market-clearing price would depress the market price by an average of about 0.34¢/kW-month. Assuming that the ISO rules allow Cape Wind to bid below the market-clearing price and that it receives about 174 MW of capacity credit, the plant would reduce the capacity price by about 60¢/kW-month, or $7/kW-year. For all of New England, that would amount to a reduction in market capacity values of $225 million annually.

For Massachusetts, netting the portion of the state's load served with long-term resources by municipal utilities and long-term contracts, the benefit is likely to be on the order of $80 million. This benefit would be diminished to the extent that the lower prices due to Cape Wind encourage the retirement of capacity.

C. Renewable-Energy-Credit Prices

Q: How could Cape Wind reduce prices for renewable energy certificates in New England?

A: Assuming that enough renewable energy is available to meet the total of the regional requirements, the market price for the various categories of RECs in the various states (and the renewable premium for Vermont and voluntary renewables purchases by municipal utilities and consumers) should be set by the intersection of interrelated demand and supply curves. Under those circumstances, adding a significant increment of renewable energy (such as Cape Wind) to the supply curve should push down the market-clearing price.

Even if the supply of renewables is not sufficient to meet demand, the presence of additional supply may change the marginal alternative compliance payment that sets the market price. For example, Cape Wind might make the difference between Class-1 REC prices being set by the Massachusetts alternative-compliance payment (now \$61/MWh, rising with inflation and hence probably about \$66/MWh by 2014) and the Connecticut alternative-compliance payment of \$55/MWh (fixed in nominal terms).

In this context, it is worth noting that the Massachusetts Secretary of Energy and Environmental Affairs recently decided to restrict the use of wood-fueled generation to meet the Massachusetts Class-1 renewable standard.[9] It is my understanding that this change in policy will preclude the construction of most proposed wood-fueled biomass plants in Massachusetts, as well as reduce the market for wood-fueled plants elsewhere, tightening the supply of renewables compared to expectations even a few months ago.

D. Natural Gas Prices

Q: How could Cape Wind reduce prices for natural gas in New England?

A: The majority of the marginal supply of electrical energy in New England is generated from natural gas; natural gas directly set the marginal price in New England about 60% of the hours in 2009 and the first quarter of 2010, and

[9]Letter from Ian Bowles, Secretary of Energy and Environmental Affairs, to Phillip Guidice, Commissioner, Department of Energy Resources, July 7 2010.

must have been the underlying marginal fuel for at least some of the 20% of the time that pumped storage set the price.[10] More generation from Cape Wind or other renewables would result in less energy generated from gas, and thus less demand for gas.

Reducing demand for gas in New England would tend to reduce the market price for pipeline transportation of gas into New England, as well as, to a smaller extent, the overall demand for gas in North America. The lower gas price would further reduce the cost of power to consumers, as well as the cost of gas used directly for heating and other end uses.

Q: How much might Cape Wind reduce the prices of natural gas in Massachusetts?

A: I am not aware of any studies of the price effects of reduced gas consumption on prices in New England. A study for the New York State Energy Research and Development Authority (NYSERDA) found that reducing New York gas consumption about 14 million dekatherms (Dth) would reduce the price of gas in New York by about 2¢/Dth in 2005 dollars. Massachusetts and the rest of New England are further down the transmission system from the production areas, and inflation has increased the cost of building and operating gas transmission since 2005, so a similar analysis for Massachusetts might well find a similar ratio of price change per Dth saved.

If the 1,520 GWh of electricity supplied annually by Cape Wind displaces gas in 70% of hours, at an average marginal heat rate of 9 Dth/MWh (for a mix of combined-cycle, combustion turbine and steam generation), it

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[10] 2009 Annual Markets Report, ISO New England Internal Market Monitor, May 18, 2010, p. 80; 2010 First Quarter Quarterly Markets Report, ISO New England, Internal Market Monitor, May 25, 2010.

would displace about 9.6 million Dth. Interpolating from the NYSERDA study suggests that the gas price reduction from Cape Wind's operation might be about 1.4¢/Dth. As with the electric price effect, this change is small compared to market prices on the order of \$5–\$8/Dth, but the quantities affected are large. Massachusetts consumers (not including electric power generation) use about 220 million Dth annually, and would save about \$3 million annually. Other New England consumers would save millions more.

In addition, the lower gas price would reduce the cost of gas for electric generation. Assuming the same average marginal heat rate of 9 Dth/MW and 70% gas at the margin, the 1.4¢/Dth would reduce the market electric price by an average of about 9¢/MWh, saving Massachusetts consumers about \$5 million annually.

Q: Is it possible that Cape Wind would not displace as much gas as you assume in your computations?

A: Yes. The other energy source that is at the margin in a large number of hours in New England is coal, which is the marginal fuel for about 25% of hours. If gas prices are very low and prices for coal and allowances rise, coal could become the marginal fuel in more hours. In that situation, Cape Wind would displace more coal energy, and perhaps even contribute to the earlier shut-down of existing coal plants. The market-price benefits would be reduced if less gas were backed out, but the environmental benefits would be greater.

IV. Other Issues

Q: What other issues do you consider in this section?

A: My clients have asked me to comment on the following issues:

- The need for the contract to facilitate the development of Cape Wind,

- Whether Cape Wind would improve the reliability of bulk power supply for Massachusetts and New England,
- The effect of Cape Wind on the reliability of the supply of renewable energy to Massachusetts,
- Whether Cape Wind moderates the electric system peak loads,
- Whether NGrid customers would benefit from a price hedge and price predictability from the proposed PPA.

A. The Need for the Contract

Q: Do new renewable resources need purchased-power agreements?

A: For the most part, building a new generation resource in New England requires a purchase commitment. Very little generation has been added to the New England system over the last few years, other than the following resources:

- small units using net metering,
- resources owned by municipal utilities (see footnote 8, above),
- plants under contract to utilities (Devon, Waterbury, Lempster Wind) or customers (e.g., half of Stetson Wind),
- plants otherwise supported by states or utilities (e.g., the Kimberly-Clark cogenerator in Connecticut).

The conventional wisdom in the renewable-energy industry is that new projects require purchased-power agreements to obtain financing, aside from those developed by NextEra, which finances its wind farms internally.

Q: Is there any reason that the proposed purchased-power agreements would be particularly important for Cape Wind?

A: Yes. The Cape Wind project is unusually large for a New England renewable project and, as the first off-shore wind farm in North America, would represent a new type of renewable resource. But the scale and the risk of the Cape Wind project would make this project especially difficult to finance without a long-term PPA.

Also, having a signed purchased-power agreement reduces the financing cost of a generation resources. As a relatively high-investment technology, off-shore wind would benefit more from the lower cost of capital than would lower-investment technologies (e.g., on-shore wind, biomass).

B. Reliability of Bulk Power Supply

Q: Would Cape Wind contribute to the reliability of New England's bulk power supply?

A: Yes. Any project that generates electricity at times of stress on the supply system—created by various combinations of high loads, generation outages, and transmission constraints—increases the reliability of bulk power supply. Offshore wind, which appears to generate a fair amount of energy at high-load summer periods, provides more reliability per kilowatt of installed capacity than wind from inland sites, many of which generate mostly at night and in the winter.

C. Electric System Peak Loads

Q: Would Cape Wind reduce electric system peak loads?

A: It is not clear what the Legislature meant by its reference to "moderating system peak load requirements" in the Green Communities Act. If the term means "the amount of energy that must be supplied by conventional generation at high-load hours," Cape Wind would certainly decrease average peak loads.

D. Price Hedge and Predictability

Q: Would the proposed purchased-power agreement provide a price hedge that would improve the predictability of power prices for Massachusetts power consumers?

A: Yes. That would be true for any purchased-power agreement with fixed pricing, that is, prices that do not vary with market prices. The price of Cape Wind power would not rise in response to increases in prices for natural gas, electric energy, capacity, or RECs. If gas prices spike, a large amount of coal capacity is retired due to environmental constraints, and the New England nuclear plants are shut down due to safety concerns, electricity prices may rise dramatically for some time. The Cape Wind purchased-power agreement, like most similar agreements, would not.

In the situation I just described, purchased-power agreements that include adjustments for gas prices would rise in price along with the gas spike. The same would likely be true for purchased-power agreements that flow through market prices of biomass.

Q: Does this conclude your testimony?

A: Yes.