STATE OF CONNECTICUT

BEFORE THE DEPARTMENT OF PUBLIC UTILITY CONTROL

	)	
Review of the Integrated Resource Plan	)	**Docket No. 08-07-01**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE OFFICE OF CONSUMER COUNSEL

Resource Insight, Inc.

SEPTEMBER 17, 2008

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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 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 approximately two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in 24 states and three Canadian provinces, and two Federal agencies.

Q: Have you testified previously before the Connecticut Department of Public Utility Control (the Department)?

A: Yes. I testified in the following dockets:

- No. 83-03-01, a United Illuminating (UI) rate case, on behalf of the Office of Consumer Counsel (OCC), on Seabrook costs.
- No. 83-07-15, a Connecticut Light and Power (CL&P) rate case, on behalf of Alloy Foundry, on industrial rate design.
- No. 99-02-05, the CL&P stranded-cost docket.
- No. 99-03-04, the UI stranded-cost docket.
- No. 99-03-35, the UI standard-offer docket.
- No. 99-03-36 (initial phase), the CL&P-standard-offer docket.
- No. 99-08-01, investigation into electric capacity and distribution.
- No. 99-09-12, the nuclear-divestiture plan for CL&P and UI.
- No. 99-09-03, on the performance-based ratemaking proposal of Connecticut Natural Gas.
- No. 99-09-12 RE01, on the Millstone auction.
- No. 99-03-36 RE03, on CL&P’s Generation Services Charge.

- Nos. 99-04-18 Phase 3 and 99-09-03 Phase 2, on the proposed earnings-sharing mechanism of Southern Connecticut Natural Gas and Connecticut Natural Gas.
- No. 03-07-02, on behalf of AARP, on the distribution investment plan and rates for CL&P.
- No. 03-07-01, on behalf of AARP, on the application of the rate cap to CL&P's transitional standard offer.
- No. 03-07-01RE1 and 03-07-15RE2, on CL&P and UI requests for incentives for mitigating transitional standard offer costs.
- No. 05-07-18, on whether capacity contracts impose costs on the electric utilities.
- No. 06-01-08, on multiple rounds of procurement results, on lessons learned from the procurements, and on procurement options.
- No. 05-07-14PH2, on the cost-effectiveness of capacity contracts proposed under the Energy Independence Act.
- No. 07-08-24, on the process for the procurement of peaker capacity.
- No. 08-01-01, on the evaluation and selection of contracts for new peakers.

Except as noted above, this testimony was on behalf of the OCC. I also testified on behalf of the OCC in Connecticut Siting Council Docket No. 217, on transmission upgrades to southwestern Connecticut.

Q: Have you been involved in other activities relevant to this proceeding?

A: Yes. I was a co-author of the 2007 report on New England avoided costs that is the basis for the avoided generation costs used by the utilities in screening their energy-efficiency programs.[1] I have also been involved in the review of numerous integrated resource plans over the past two decades, and have been involved in developing resource plans, most recently for the City of New York and the Province of Ontario.[2]

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Office of Consumer Counsel.

Q: What is the purpose of your direct testimony?

A: The Office of Consumer Counsel has asked me to review the filings in this proceeding of CL&P and UI (the utilities), their consultant Brattle Group, and the Connecticut Energy Advisory Board (CEAB) and its consultant La Capra Associates, to identify areas in which the analyses and/or the policy recommendations may not be sufficiently protective of the interests of consumers.

John Plunkett will be testifying on several issues in related to the role of energy-efficiency programs in the IRP. My testimony deals with future market prices in Connecticut, the effect of additional supply and demand resources on market prices, the likelihood of retirements of older steam-electric power plants

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[1] Hornby, Rick, Carl Swanson, Michael Drunsic, David White, Paul Chernick, Bruce Biewald, and Jenifer Callay. 2007. “Avoided Energy Supply Costs in New England” 2007 Final Report.” Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid.

[2] “Chernick, Paul, Jonathan Wallach, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta. 2003. “Energy Plan for the City of New York.” New York: New York City Economic Development Corporation. Chernick, Paul, Jonathan Wallach, and Richard Mazzini. 2008. “Green Resource Portfolios: Development, Integration, and Evaluation.” Report to the Green Energy Coalition, Pembina Institute and Ontario Sustainable Energy Association presented as evidence in Ontario EB 2007-0707.

in Connecticut and elsewhere in New England, the role of demand response, procurement of renewable resources, and the recovery of IRP resource costs.

Q: What documents did you review?

A: The many documents I reviewed include the following:

- "The Integrated Resource Plan for Connecticut;" Brattle Group, CL&P, and UI; January 1, 2008 (the IRP). For simplicity of exposition, I assume in this testimony that the IRP was the product of Brattle.
- "Initial Review of Integrated Resource Plan for Connecticut;" La Capra Associates; January 28, 2008.
- "2008 Comprehensive Plan for the Procurement of Energy Resources;" Connecticut Energy Advisory Board; August 1, 2008 (the Procurement Plan)
- "Documentation Report for Supplemental Analysis Requested by the CEAB via La Capra Associates, Inc.;" Brattle Group, CL&P and UI; August 1, 2008 (the Supplement).
- "Avoided Energy Supply Costs in New England: 2007 Final Report;" prepared for Avoided-Energy-Supply-Component (AESC) Study Group by Synapse Energy Economics, Resource Insight, and Swanson Energy Group, August 10, 2007 (2007 Avoided-Cost Study). This study, which I co-authored, was the basis of the avoided costs used by the utilities and the Energy Conservation Management Board (ECMB) in screening DSM for the IRP.
- Various documents from Dockets 05-07-14PH2, 07-08-24, and 08-01-01.
- Various reports from ISO-NE.

Q: What is your general evaluation of the IRP and the Supplement?

A: While the supplemented IRP is a reasonable first effort in a continuing process, the structure, scope, documentation, and accuracy of its analyses are inadequate to support any major decisions.

There are at least two important dimensions to the evaluation of the IRP. The first concerns how well the utilities have done, given the time constraints for this particular filing. Having had significant responsibility for development of IRP-like reports, I am sympathetic to the utilities' difficulties in producing the first IRP in Connecticut in roughly a decade within seven months of passage of PA 07-242. While CL&P has access to some internal supply-planning resources, due to the continued ownership of generation by its affiliate Public Service of New Hampshire, it has not been in the business of developing new supply resources since the beginning of restructuring. UI gave up its generation planning and supply functions as part of restructuring. Within those constraints, however, the utilities could have spent their resources better, concentrating more on the implications of important near-term choices, such as alternative timing and pacing of energy-efficiency and demand-response efforts, and potential benefits from transmission upgrades and long-term contracts. Nonetheless, I consider the IRP to be a good first effort.

The second dimension concerns the quality, depth, and breadth of the IRP analysis. In Sections IV and V below, I discuss numerous problems in the assumptions, modeling, and documentation of the IRP and Supplement. Some of the problems in the Supplement appear to originate with La Capra, as consultant to the CEAB, rather than Brattle and the utilities. The Department should be very wary of relying on this IRP or Supplement for more than general guidance. This proceeding should focus more on improving the annual IRP process going forward than on approving specific resources.

III. Purpose and Goals of the Integrated Resource Plan

Q: What is the appropriate scope for this and subsequent IRPs?

A: The purpose of an IRP is to integrate the resource-planning process, define policy priorities, determine the approximate composition of the future resource mix, and ensure that mechanisms exist to achieve that mix. In Connecticut, mechanisms exist for design, refinement, review, and implementation of energy-efficiency programs; procurement of short-term and potentially long-term power supply for Standard Service and SLR; design and approval of local and regional transmission investments; and approval of long-term renewable energy contracts. The IRP process should provide input and guidance for those other mechanisms, without duplicating those processes, and should identify additional processes that are necessary to procure resources beyond the existing structures. The IRP also provides an opportunity to look at resource procurements beyond the planning horizon of the C&LM, Standard Service procurement, and most other planning processes.

The IRP should not normally engage in detailed energy-efficiency program design, select specific resource locations or vendors, or otherwise reach down to micromanage the procurement processes.

Q: What costs and benefits should be considered in utility planning?

A: At a detailed level, the relevant costs and benefits (and the appropriate estimation techniques) will vary with the types of resources and the types of decisions under consideration. A particular component (such as energy costs) may be a cost in some analyses (such as Standard Service procurement) and benefit in others (such as DSM screening). Nonetheless, regardless of the application, an important objective in utility planning is minimizing costs in the following categories:

- energy bills to Connecticut energy consumers, including delivery charges, Standard Service and SLR generation supply charges, and bills from competitive suppliers.[3]
- other costs to Connecticut consumers related to energy services, including the costs of energy-consuming and energy-conserving equipment and buildings, water, and operating and maintenance costs. yy
- environmental costs of energy production, as best those can be estimated and reflected in planning.

In Dockets 05-07-14PH2, 07-08-24, and 08-01-01, the Department applied essentially that standard, minimizing costs to Connecticut ratepayers, with some consideration of the residual environmental effects.

Q: Does the IRP use one or more appropriate measures of cost?

A: No. While Brattle computes three versions of system costs (which Brattle calls "metrics"), none of them appear to be appropriate. None of the three distinguishes between customer entitlements (e.g., the EIA, peaker and Project 150 contracts; future contracts in the renewable build-out case; CMEEC entitlements) and merchant generation. It is not clear whether Brattle included participant costs in DSM costs for any of the metrics. In addition[4]

- Brattle defines *total going-forward costs* as equaling the sum of "capital carrying cost on new unplanned generation, fixed O&M, variable O&M, fuel cost, allowance cost, RPS cost, the costs of energy and capacity

[3]To the extent that multiple jurisdictions are acting in concert with Connecticut in resource planning, it may also be appropriate to include financial costs and benefits to consumers in those jurisdictions.

[4]Brattle does not provide a clear accounting of the cost components in its analyses, so it is difficult to tell what costs and benefits are included in various cost metrics. The best we have is a summary for 2018 for one case, in the Attachment to IR OCC-41.

imports into Connecticut (at market prices), and DSM program costs" (IRP p. 25).

I read this to mean that the prices paid to Connecticut generators (NRG, PSEG, Dominion, Lake Road, etc.) are ignored. Millstone's generation is priced at nuclear fuel, not market prices. This "total" cost measure excludes forward reserves (which Brattle calls "fast-start"), real-time reserves (which Brattle calls "spin"), and uplift.

- Brattle's definition of *customer costs in the market regime* are closer to what customers pay, but this measure does not reflect the effects of customer entitlements, includes a rather high 15% retail adder on generation costs. Also, despite the title, Brattle assumes that the RPS and capacity price in this case are set by long-term contracts, rather than market prices.[5]
- Brattle's definition of the *customer cost in the cost-of-service regime* omits reserve requirements and assumes that the Connecticut utilities would be able to purchase all the existing generation in Connecticut (including plants never owned by utilities) at unspecified, but apparently below-market, prices.[6] This case would have been much more useful were it more realistic, reflecting utility ownership of most new generation, for example, or repurchase of some capacity at market prices.

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[5]This metric also includes an unexplained "Adjustment for Overcounting Losses" and, at least in the example we have seen, this metric a very small adjustment for FTRs, described incomprehensibly as "Assume 75% Coverage for Internal Gen to Load" (Attachment to IR OCC-41).

[6]Curiously, the renewables are still priced for contract purchases rather than utility ownership.

In short, the cost accounting in the IRP is poorly explained and inconsistent. None of the cost measures represents the costs to Connecticut power consumers under current or plausible future market structures.

Q: Many of the recommendations in the Procurement Plan regard long-term contracting to reduce generation costs, including the price of renewable generation. Is this appropriate under the current regulatory paradigm of deregulated markets?

A: Connecticut has a mixed system that includes the following competitive elements:

- the nominally competitive markets of ISO-NE,
- competition among third-party generation-service providers in bundling the products from those markets directly to retail customers and through the utility's Standard Service and SLR products,

as well as many components that are regulated, cost-of-service, or otherwise very different than the open-access competitive model of the ISO, as follows:

- transmission planning and construction by the regulated utilities and the ISO, with cost-of-service rate recovery;
- the vertically-integrated municipal utilities;
- utility long-term contracts for resources:
  - the EIA contracts in Docket 07-08-24,
  - the peaker contracts in Docket 08-01-01,
  - the renewable contracts of Docket 03-07-17, its reopenings, and Docket 08-03-03,
- state capital grants for distributed generation;
- long-term contracting for energy and capacity for Standard Service, under Docket 07-06-58;

- energy-efficiency programs of the utilities;
- demand-response programs of the utilities;
- procurements that may be authorized under the IRP statute.

Most of these regulated activities were explicitly encouraged by legislation, and reliance on these initiatives, especially through the IRP process, seems likely to continue. The market will set reference prices, and may provide alternatives, but the utilities and DPUC have obligations to ratepayers beyond just passing on the market price. The competitive markets are the sea in which all New England ratepayers now swim; the utilities, CEAB, and DPUC (with the advice and assistance of ECMB, CCEF, and OCC) are charged with building a raft to keep Connecticut customers from getting soaked.

Q: Does procurement of a resource through an IRP preclude any role for competition?

A: No. Many resources can be procured through a variety of mechanisms, from direct construction and operation by a utility or a state agency; to bidding by potential suppliers to provide services defined by the utility or agency (such as installing specified energy-efficiency measures or small renewables); to purchases of products (energy, capacity, reserves) through auctions, bidding, or other competitive procurement.

IV. Market Conditions

A. Modeling ISO-NE Markets

Q: What types of benefits may result from the resources acquired as the result of a Connecticut IRP?

A: The benefits of various resources include market price revenues, reduction in the market products purchased to meet load, reduction in market prices, reduced T&D costs outside the ISO-NE market system, and environmental benefits (such as reduced pollution from the old steam-electric generator). The most significant market benefits are in the energy, forward-capacity, and locational-forward-reserve markets, which I identify below as E, C, and R, respectively.

Table 1: Summary of Resource Benefits

Resource Type	Market Revenues			Reduced Purchases			Reduced Market Prices			T&D Costs	Environmental Benefits
	E	*C*	*R*	*E*	*C*	*R*	*E*	*C*	*R*		
Peaker—LFRM	○	✓	✓					✓	✓		✓
Distributed Generation	✓	✓					✓	✓		✓	✓
Other Generation	✓	✓					✓	✓			✓
Energy Efficiency	✓	✓		✓	✓					✓	✓
Demand Response		✓	?					✓	?	?	

Key: ✓ *clear benefit* ? *possilble benefit under some circumstances* ○ *very small benefit*

Whether a resource is cost-effective depends on whether the present value of these benefits exceeds the present value of the costs of acquiring the resource.

Q: Which of these benefits will you be discussing in more detail?

A: I will discuss in the following subsections the market prices of energy, capacity and reserves, and the effect of additional resources on these market prices. With regard to the other benefits, I have only the following brief comments:

- For resources that are procured on a continuous basis, particularly energy efficiency, the utilities should develop a method of updating avoided energy costs to reflect forward-market prices when those change significantly, and updating avoided generation capacity costs to reflect the results of the annual forward capacity auctions.
- Energy costs dominate customer electric bills, and a given percentage change in energy prices or energy usage has a much larger effect on

- customer costs than an equal percentage change in peak demand or the price of capacity or reserves.
- Increasing capacity or decreasing loads at times of high demand reduce capacity prices and/or increase reliability on the generation, transmission and/or distribution systems.

1. Forward Energy Prices

Q: How do current forward energy prices for New England electricity compare to the forward energy prices at the time the current avoided costs were developed?

A: The forward energy prices used to benchmark the energy market model were from May 2, 2007 (Hornby et al., op. cit., p. 5-21). The following table compares those forward prices to the prices on August 28, 2008, including the simple average of peak and off-peak prices:

Table 2: NYMEX Forward Prices for ISO-NE Hub

	5/2/2007			**8/28/2008**			**Increase 07-08**		
	On	*Off*	*Average*	*On*	*Off*	*Average*	*On*	*Off*	*Average*
2009	90.5	68.2	79.3	95.7	73.4	84.5	6%	8%	7%
2010	87.2	67.0	77.1	95.0	72.6	83.8	9%	8%	9%
2011	85.2	65.6	75.4	92.4	70.6	81.5	8%	8%	8%
2012	79.4	67.5	73.4	90.7	68.2	79.5	14%	1%	8%

Energy delivered to Connecticut is not widely traded, so no comparable forwards are available for Connecticut prices. Energy delivered to Connecticut tends to cost roughly 5%–10% more than the prices at the Western Massachusetts hub, on average.

The market price of electric energy in New England varies with the price of natural gas, which in turn varies with national and international supply and demand conditions. Current and forward electric energy prices tend to be highly volatile, due to variation in gas prices, local electrical demand, power-plant availability, and generator bidding behavior.

Q: How would additional resources affect market-clearing energy prices for Connecticut consumers?

A: Additional resources, to the extent that they reduce energy requirements or produce energy at low variable costs would tend to reduce market energy prices at the ISO hub and the congestion from the hub to Connecticut. Thus, energy efficiency, and most generation would tend to reduce market energy prices, while demand response, emergency generation and peakers providing forward reserves would have little effect on market energy prices.[7]

In the 2007 avoided-cost report (Hornby et al.), using historical data on loads and prices by zone, I estimated that every MWh reduction in 2006–2007 energy requirements in Connecticut reduced Connecticut energy prices about 1¢–2¢/MWh, while reducing prices in other states by lesser amounts. Since Connecticut's annual energy load is about 34,000 GWh, or an average of 4,000 MW, the reduction in prices would be worth about $40–$80 per MWh saved or supplied, if all energy is purchased at market prices. To the extent that energy is procured under contracts predating the effect of the price reduction (e.g., long-term procurements by municipal utilities, contracts with competitive energy suppliers, or standard-service supply), the price effect would be reduced.

These effects are likely to be temporary. Reductions in load and increases in supply with low energy prices tend to drive down market energy prices, but those lower prices tend to discourage development of resources that require high energy prices to be feasible. Lower energy prices may also result in deactivation

[7] Generators providing forward reserves are required to bid into the energy market at high prices, so they will not be dispatched much.

or retirement of plants dependent on high energy costs. Determining the duration of the energy-price effect is difficult; in the 2007 avoided-cost report, I estimated a life of four years, with declining effects over that period. That estimate should be revised in light of the results of the first auction for the forward capacity market. Estimating the rate of retirements and renewable development is difficult. Any estimate of the effect of lower energy prices on those processes (and hence the rate at which energy prices would rebound) is likely to be little more than a guess.

Future IRPs should explicitly estimate the effect of energy-efficiency and generation resources on energy prices in Connecticut.

2. Forward Capacity Prices

Q: How does the IRP project forward capacity prices?

A: Brattle assumed that the price in the forward capacity market would start at the $4.50/kW-month floor for 2010/11, and "will then trend toward Net CONE when the market reaches supply/demand equilibrium in 2013–16, depending on the scenario" (IRP p. A-11). Brattle estimated that the equilibrium price would be determined by the costs of a combined-cycle plant, rather than the combustion turbine the ISO-NE used in setting the CONE. Brattle projected that combined-cycle units would bid into the 2010/11 auction at about $4/kW-month.

Q: What is the basis of Brattle's projection of combined-cycle capital costs?

A: Strangely enough, Brattle does not start with actual costs of combined-cycle units, or even announced costs or the result of studies on combined-cycle costs. Instead, Brattle begins with a 2004 estimate of combustion-turbine capital costs, adds 20% inflation, and multiplies by 1.5 to estimate combined-cycle costs (IR OCC-25, especially attachment "Tech_Screening_Base.xls," sheet "Costs Reed

2004”). Reported gas-plant construction costs have risen much more than 20%—more like 60%—since 2004; see Figure 1, on page 38 below.

Q: How did Brattle compute the annualized carrying charges for a new combined-cycle plant?

A: Brattle assumed that the plant would have a long-term contract (IR OCC-26c), making the combined-cycle plant more analogous to the non-utility generators of the 1980s than to a merchant generator. The IRP does not identify any party who would be contracting with the combined-cycle plants. The implicit assumption seems to be that market prices will be set indefinitely by the long-term contracting efforts of utilities or state agencies. In any case, the use of contract financing, rather than merchant operation, would reduce the cost of capital and hence the annual carrying charges of the combined-cycle.

Q: Were Brattle’s projections of $4/kW-year bids by borne out by the first capacity auction?

A: Not entirely. The February auction for 2010/11 did clear at $4.50/kW-month. But no combined-cycle plants bid into the auction at any price, and the bids suggest that FCM prices may remain depressed for some time.

The combined-cycle bids in Docket 07-04-24, net of energy revenues, were well in excess of the cost of new combustion turbines as estimated by both ISO-NE and Brattle. In addition, Brattle assumed that the combined-cycle unit setting the FCM price would be financed through a long-term contract from a utility (or some other credit-worthy entity). That seems unlikely, since a unit under contract will normally bid to clear in the auction, without reference to its underlying costs. After all, the unit will be built and operated regardless of the FCM price. More likely, the market will be set by resources without contracts, which will be more expensive to finance.

At the auction floor price of $4.5/kW, suppliers offered more than 2,000 MW of capacity in excess of the ISO's requirement. Connecticut has another 1,434 MW of new capacity under contract: Kleen, Project 125, and the peakers.[8] Some renewables will be developed in New England in response to the state renewable portfolio standards (RPS) and actions utilities take to meet them.

Q: How much renewable capacity is likely to be developed in New England?

A: That is a difficult question. As is clear in the IRP and the Supplement, a large amount of renewables would be required to meet the RPSs.[9] Large amounts of renewables have been proposed in New England, New York, New Brunswick, and Quebec. Historically, a large fraction of proposed generation (including wind generation) has failed to reach commercial operation. The high prices of renewable-energy credits (RECs), added to energy and capacity revenues, may well bring a large amount of renewable generation to commercial operation, although large amounts of wind generation, in particular, may not survive the siting process.

In the 2008 Regional System Plan, ISO-NE reported that 1,845 MW of wind and about 600 MW of other renewables were in the interconnection queue as of March 15, 2008.[10] By August 8, the amount of wind in the queue had

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[8]The Waterside and Waterbury peakers are included in the surplus from the first auction, since Waterside exists and Waterbury bid less than the floor price.

[9]The Connecticut RPS may be met in part by designating existing gas-fired units as renewable, based on the concept that they are effectively burning pipeline-quality gas from landfills outside New England.

[10]Third Draft 2008 Regional System Plan, ISO New England System Planning, August 27, 2008, Table 8-7.

increased to 3,782 MW.[11] It is not clear how much qualified capacity will be credited to each megawatt of wind (or some hydro), since that depends on output of each plant during the Summer and Winter Reliability Hours.

Even if wind is valued at only 20% of nameplate, the queue currently includes about 1,350 MW of potential qualified capacity. If 70% of that capacity reaches commercial operation over the next decade, about 100 MW of renewables would be added each year. Imports of renewable energy to meet RPSs may also bring capacity credits, but not necessarily.[12]

Q: What is your current expectation of forward capacity prices?

A: Assuming no retirements or other delistings beyond Norwalk Harbor (which would have delisted in the first auction, but for a Connecticut supply constraint that will be relieved by the Kleen plant), and just 100 MW a year in new resources (renewables, DR, and energy-efficiency) in New England, I estimate that FCM prices would remain below the $4.50/kW-month price of the first auction through 2020/21, and remain below the ISO estimate of CONE through 2025/26. My projection is provided in Exhibit PLC-2.

Q: How does Brattle's projection of the capacity balance differ from yours?

A: Since the IRP was prepared prior to the first FCM auction, and was based on the 2007 CELT forecast, rather than the 2008 CELT, the relevant comparison is to Brattle's update in IR OCC-18. Even the Supplement, despite its August 2008

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[11]Some of the hydro projects in the queue are redevelopment, or perhaps just changes in the transmission connections of existing projects, so it is difficult to determine the amount of propose additions.

[12]For example, the contract between the Maple Ridge wind plant in New York and NStar covers energy and RECs, while leaving the capacity value for Maple Ridge to sell into the New York market.

date, still uses the 2007 CELT and ignores the auction results. A precise comparison is difficult, since Brattle's categories are different from mine, and I cannot determine how much of Brattle's DSM category is demand response that cleared in the first FCM auction, how much is demand response offered in the first auction, and how much is future demand response offering and energy-efficiency efforts. Brattle also includes RPS-driven new renewables only in the Supplement. However, Brattle explicitly rejects the retirement of Norwalk Harbor, despite that plant's failure to clear in the 2010/11 auction (IR OCC-18). With the update, and without any new renewables, Brattle projects a continuing capacity surplus through about 2020.

Q: Is Connecticut likely to become a separate capacity zone under current ISO rules?

A: No. Brattle's analysis in Table 2.3 of the IRP suggests that capacity in Connecticut is likely to exceed the Connecticut local sourcing requirement except in the most extreme circumstances, such as retirement of most of the Connecticut steam capacity combined with high load growth, attrition in demand response, and poor results from the energy-efficiency programs. Table 2.3 includes only 279 MW of capacity from the peaker contracts; the Department actually approved about 670 MW of peakers, so the safety margin between Connecticut supply and the local sourcing requirement is larger than indicated in Table 2.3 of the IRP.

Q: How should the utilities improve the treatment of the forward capacity market in future IRPs?

A: The utilities should update the input assumptions for load, resources, and cost, and should clarify whether they expect market prices to be set by merchant generators or utility contracts.

3. Effect of Additional Resources on Capacity Prices

Q: How would additional resources affect forward capacity prices?

A: All else equal, additional capacity resources—resources that reduce load at peak or add forward capacity that clears in the auctions—will generally reduce FCM prices to customers. The exceptions to this general rule occur when forward capacity prices are at their regulated floor prices, as they were in the first auction, and when the additional resources result in some other capacity dropping out of the ISO capacity supply.

Q: Without further retirements, how long do you expect the forward-capacity price to remain at the ISO's floor price?

A: The floor price in any particular forward capacity auction is a function of the clearing price in previous auctions. The floor in the 2010/11 auction was $4.50/kW-month; in 2011/12 it will be $3.60. If the clearing price continues to fall, the floor price will continue to decline, as shown in Exhibit PLC-2. Given the assumptions I discussed above, the capacity price could continue to follow the floor downward through the 2014/15 auction, at a price of $2.28/kW-month. In all the years from 2009 through May 2015, additional capacity resources would have no effect on the market price.

Q: What would be the effect of additional capacity resources after the 2014/15 auction?

A: Based on the shape of the supply curve for bids just above the floor price in the first auction (in the range $4.50–$5.25/kW-month), I project that the forward capacity price would decrease by about 2¢/kW-year per megawatt of additional capacity. The exact effect will depend on the details of the bids in future auctions; our limited experience with the FCA suggests that the effect may be 1–10¢/kW-year per megawatt over various levels of surplus. Even at the low end of the range, reducing the price of about 7,000 MW of market FCM obligations (Connecticut peak plus reserves minus contract entitlements would be worth about $70,000 annually for the entire state for each megawatt of additional supply or $70 per kW-year. In this period, the price benefit to Connecticut consumers is likely to be greater than the direct avoided capacity cost.

Q: Does that effect per MW stay constant?

A: No. At some point, the bid curve should become flatter, as various new generators become marginal. I would expect the differences in the bids from those generators to be relatively small. In Exhibit PLC-2, I estimate that point to be about 2025.

Q: What are the implications of your results for resource planning?

A: Under these assumptions, the value of capacity is quite low for several years, suggesting the demand-response and other resources that are very dependent on the value of capacity are not likely to be very valuable. Acquiring those resources is not likely to be cost-effective until well into the next decade. Nor are additional resources likely to substantially affect capacity prices until after 2014.

4. Forward Reserve Costs and Effects of Additional Resources

Q: How does the IRP project forward reserve prices?

A: Brattle assumed that the locational-forward-reserve-market (LFRM) price in Connecticut would always be the ISO's cap price, which is $14/kW-month minus the FCM price (IR OCC 31).

Q: Is this a reasonable assumption?

A: No. As Brattle was preparing the IRP, the Department was engaged in Docket No. 07-08-24, and then 08-01-01, to procure long-term cost-of-service contracts with new peaking capacity, particularly to end the shortage of forward reserves in Connecticut and reduce LFRM prices.

Brattle also did not reflect the reduction in uplift costs as fast-start peaking capacity is added, reducing the ISO's dependence on expensive spinning reserves from the old steam plants.

Q: How should the IRP have forecasted LFRM prices as the amount of forward reserves in Connecticut increases?

A: In Docket No. 08-01-01, Resource Insight and Levitan Associates both did extensive analysis of the potential effects of additional forward-reserve capacity on LFRM prices in both the ten- and thirty-minute reserve markets. Given the limited data available, the two firms produced different estimates. The utilities should review the record in that proceeding, and if necessary consult with Resource Insight and/or Levitan, in preparation for modeling LFRM for the next IRP.

Q: How did Brattle allocate LFRM costs to Connecticut ratepayers?

A: Brattle assumed that "The cost allocation factor is...45%, to account for both Connecticut customers' share of the Connecticut LFRM costs (some of which are socialized across New England) and Connecticut's share of FRM costs from the rest of New England" (IRP p. A-14). Brattle appears to assume that Connecticut's FRM bill is always 45% of the payments to Connecticut forward-reserve providers.

Q: Is this a reasonable assumption?

A: No. The allocation of FRM costs among zones depends on on-peak energy loads and FRM prices in each of the zones. Connecticut's allocation is close to the payment to Connecticut forward-reserve providers. In Docket No. 08-01-01, Resource Insight modeled the allocation of FRM costs under the ISO rules. Again, the utilities should review (and, as necessary, improve) the modeling in that docket in preparing the next IRP.

Q: Did the IRP consider the costs and benefits of acquiring additional LFRM capacity in Connecticut?

A: No.

B. Plant Retirements and Resource Needs

Q: How do retirements of generation plants affect integrated resource planning?

A: Given the structure of the ISO-NE markets, retirement of existing generation reduces the capacity available for the forward capacity market, and hence tends to raise the FCM price. To the extent that retired units would also have generated energy or provided reserves (which varies widely among units), their retirement also increases energy prices and/or uplift, as more plants with higher variable costs are called on to perform those services.

Q: How does the IRP model retirements?

A: The IRP (p. A-6) compares the fixed O&M costs of the Connecticut plants with RMR contracts to Brattle's projection of forward capacity prices, using the O&M costs claimed in each plant's RMR filing, and finds that only Norwalk Harbor's costs would not be covered (or nearly so) by FCM revenues. Brattle then says that it

> understand[s] that those units or other new resource may be necessary for reliability in the Norwalk area in order to protect against contingencies when one of the new 345-kV transmission lines into Norwalk is out of service. Therefore, we assumed that Norwalk Harbor 1 & 2 would stay online in spite of our screening analysis. (IRP p. A-7)

Q: What is the basis for this assertion regarding the continuing need for Norwalk Harbor?

A: In response to discovery, Brattle and the utilities admit that a "definitive determination that the units are needed for reliability has not been made," assert vaguely that the "size and location of Norwalk Harbor 1 & 2 (over 300MW of capacity in the Norwalk/Stamford subarea) [make] their removal ...a greater concern than the removal of similar but significantly smaller units elsewhere in CT," and suggest that the need for capacity in the Norwalk area is demonstrated by the fact that FERC's "July 16, 2007 hearing order related to Norwalk Harbor's RMR agreement with ISO-NE...declined to set the reliability need for these units for hearing" (IR OCC-30).

Q: Does this response indicate that Norwalk Harbor, or new generation, is needed in the Norwalk-Stamford area?

A: No. The distinction between the Norwalk Harbor units and "significantly smaller units" is specious. Each of the Norwalk Harbor units is less than 170 MW, compared to 139 MW for Bridgeport 2 and 400 MW for the Middletown 4 and Montville 6 units, all of which the Supplement concludes can be retired. The reference to Norwalk Harbor's "location" does not demonstrate any capacity need in Norwalk. And the "hearing order" in which FERC supposedly "declined to set the reliability need for these units for hearing" was actually an order on a compliance filing in which "no protests or adverse comments were filed," and does not mention, let alone describe, any reliability need for the units.

Q: What reliability need has ISO-NE asserted as justifying special arrangements to keep Norwalk Harbor on line?

A: ISO-NE is quite clear that Norwalk Harbor is required for Connecticut constraints, both in the RMR filing for Norwalk Harbor (Steady State Evaluation of the Reliability Need for Norwalk Harbor 1, ISO-NE, December 15, 2006), and in the filing with FERC on the decision to keep Norwalk Harbor on line, even though its bid in the first FCM auction exceeded the clearing price (Forward Capacity Auction Results Filing, FERC Docket 08-633-000, ISO-NE, March 3, 2008). ISO-NE describes Norwalk Harbor's statewide role as follows:

- to provide adequate "operable capacity in the Greater Connecticut load Sub-area" (Steady State Evaluation, p. 2).
- to maintain "a transmission security margin for the Connecticut sub-area" (FCA Auction Results, p. 11)

Nothing in either document hints at a Norwalk-area need. To the contrary, the Steady State Evaluation suggests that the alternatives to Norwalk Harbor are "the addition of new generation within Connecticut, or an increase in the Connecticut import capability."

Q: How does the Supplement model retirements?

A: In the Supplement (p. 7), Brattle compared SO_2 and NOx emissions of each New England steam unit fired by coal or oil to La Capra estimates of unit-specific emission limits to be applied regionally by 2011 and 2018. The emission rates are based on Connecticut DEP goals in the short term (3–5 years) and long term (5–10 years) (IRP Appendix J, p. 6; IR OCC-46a). It is not clear how La Capra determined that the Connecticut goals would also be applied in other states (most importantly, Massachusetts and Maine).

For units that fail the 2018 limit for either pollutant, Brattle added the costs of SCR (for units failing the NOx goal) and/or scrubbers (for units failing the SO_2 goal) and compared the combined cost of the control equipment and normal plant operation to Brattle's forecast of energy and capacity costs. Brattle actually deviated from this rule in several situations, including the following assumptions:

- that the eight dual-fuel steam units that currently burn mostly gas (Middletown 2 & 3, Montville 5, Brayton Point 4, Mystic 7, Newington 1, and West Springfield 3) would comply by switching to burning 100% gas (and in the case of the first four units, install SCR) and continue operating. This is probably a reasonable assumption, at least as to the effects of emissions regulation on these units.
- that the two dual-fuel steam units that currently burn mostly oil (Canal 2 and New Haven Harbor) would expand their gas supply and switch to burning 100% gas. This is not so clearly a reasonable assumption. Brattle did not consider either the costs of the additional gas supply or the technical ability of the units to operate at full load on gas (IR OCC-52 and 53). New Haven Harbor would require "significant boiler modifications" to operate above 40% of rated power on gas (IR OCC-52). It would not be surprising if the costs of building additional gas supply and modifying the boiler to run at full capacity on gas might exceed the units' projected revenues.

- that the units that serve the district-heating systems in Cambridge and Holyoke would shut down, without consider the need for the Cambridge or Holyoke units (or replacements) for the steam systems (IR OCC-56).[13]

From its economic analysis, Brattle projects that about five Connecticut units (Norwalk Harbor 1 and 2, Montville 6, Middletown 4, and Bridgeport Harbor 2) totaling 1,267 MW, would retire, along with another 1,084 MW at Canal 1 and Cleary 8 in Massachusetts. and Wyman 1–4 in Maine.[14] This would be all of New England's remaining oil-only steam capacity.

Q: Other than the problems you pointed out above, are there other weaknesses in the retirement analysis?

A: Yes. I have identified two such problems. First, while La Capra provided DEP targets for 2011, and Brattle included those targets in the Supplement, Brattle did not evaluate the economics of retirements "separately for the 2011 and the 2018 emission limits due to time constraints. Only 2018 emission limits were evaluated" (IR OCC-49). Hence, the retirements analysis in the Supplement is presented as raising concerns only in the long term. A quick comparison of emission rates and limits suggests that nearly all the units that would be out of compliance in 2018 would also be out of compliance in 2011, as demonstrated in Exhibit PLC-3. Unless the market prices are much higher in 2011 than Brattle anticipates for 2018, nearly 1,700 MW of steam capacity may fail to clear in the

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[13]Brattle also assumed the retirement of a 10-MW Somerset coal plant in Maine. It turns out that the Somerset plant burns biomass, not coal (IR OCC-54).

[14]The Supplement does not reconcile the conclusion that Norwalk Harbor would retire with the IRP's apparently incorrect insistence that Norwalk Harbor (or some replacement in the Norwalk-Stamford area) is essential. The 1,048-MW value is compiled from the capacities listed in the Supplement, which lists Canal 1 as having a capacity of only 254 MW. However, the 2008 CELT lists Canal 1 as having a summer capacity of 550 MW.

2011/2012 FCM auction.[15] If Brattle is wrong about the ability of Canal 2 and New Haven Harbor to economically switch to 100% gas firing, another 1,000 MW may be deactivated.[16] New Haven Harbor appears to have NOx emissions high enough to violate the 2011 emission goals ("Implementing High Electric Demand Day (HEDD) Strategy," Wendy Jacobs, Rick Rodrigue, January 10, 2008, SIPRAC Meeting).

Q: What is CEAB's position on the implications of La Capra's environmental assumptions to the analysis of retirements for 2011?

A: The CEAB was unaware that "nearly all the units that would be out of compliance in 2018 would also be out of compliance in 2011" (IR OCC-50a). Even though the CEAB had requested the effect of emission limits on retirements, the CEAB does not seem to place much faith in that analysis:

> The CEAB does not believe it is reasonable to 'expect' retirements in 2011. These economic tests are indicative of potential for retirement, but are not the exclusive basis for retirement decisions that owners of these assets will consider. (IR OCC-50b)

It is not clear what reliance the CEAB would place on this analysis (if any), or why.

Q: What was your second concern with the retirement analysis?

A: The retirement analysis considered only the effects of emissions controls, added to the basic O&M, fuel, and emission-allowance costs and market-price assumptions. Plant retirements are also triggered by the need for other investments, such as when major plant components (e.g., boiler, turbine, generator) fail or require major reconstruction. Other types of environmental

[15]This computation includes the full 550-MW capacity of Canal 1.

[16]The exact timing of the retirements would depend on the timing of mandatory emissions limits in Connecticut, Massachusetts, and Maine.

improvements, such as the cooling towers that Dominion has agreed to install at Brayton Point, can impose capital costs, operating costs, reduced capacity, and higher heat rates.[17] Brattle did not include any allowance for routine capital additions, or for large additions due to equipment failure or other environmental requirements.

Q: How should the utilities and CEAB improve their treatment of retirements in future IRPs?

A: Retirements of older capacity would have salutary environmental effects, but could have important effects on power supply and price. The utilities and CEAB should improve their modeling of retirement risks by including the following in their analyses:

- realistic projections of unit-specific emission limits (and not just goals) by state, for Connecticut, Massachusetts, Maine, and possibly New Hampshire;
- careful consideration of technical and economic barriers to 100% gas operation by Canal 2 and, especially, New Haven Harbor;
- the potential for lower-cost environmental compliance, including lower-sulfur oil (rather than switching to 100% gas or retiring units) and the use of selective non-catalytic reduction (SNCR) rather than the selective catalytic reduction (SCR) assumed in the Supplement;[18]
- Consideration of potential environmental requirements other than NOx and SO_2 controls;

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[17]The costs of complying with mercury emissions may be important for some coal units.

[18]One major advantage of SNCR for the oil and gas steam units, with their low capacity factors, is the avoidance of the large fixed costs of the catalyst and ductwork required for SCR.

- Recognition of the effects of periodic major equipment failures on the economics of continued unit operation.

C. Potential Future Capacity Balance

Q: Given your analysis of the capacity market with existing and announced changes, and the Supplement's analysis of economic retirements, what is the plausible range of the regional capacity balance over the next decade?

A: The range is quite broad. If the economic assumptions of the La Capra-Brattle retirement analysis are essentially correct, some 1,700 MW of capacity would retire in 2011 or shortly thereafter, depending on the vigor with which DEP and its counterparts in other New England states pursue the emission limits.[19] Those retirements would cause the FCM price to rise above the floor price by the 2013/14 auction (two years earlier than my estimate without the retirements); and rise above the $4.50/kW-month in the 2015/16 auction, six years earlier than without retirements; and reach the ISO's estimate of the cost of new entry in 2020, about six years earlier than without retirements.

Q: Is this particular outcome likely?

A: I do not believe it is. A number of factors may reduce the speed with which the capacity price rises. The rate of implementation of unit-specific emissions requirements may be slower than La Capra assumes, the costs of compliance may be less, more energy-efficiency and renewables may be developed than the 100 MW/year I assumed, and load growth may be less than expected in the 2008 CELT. On the other hand, most of these factors can go the other way, with

[19] This 1,700 MW uses the correct capacity for Canal 1 but does not include the small steam units (Kendall, Holyoke, and the nonexistent Somerset unit) that Brattle includes.

additional retirements, less energy-efficiency and renewable development, and faster load growth.

Q: Is New England likely to require intervention by the states or utilities to maintain sufficient capacity over the next decade?

A: No. Even with the retirements implied by the Brattle analysis, capacity would be adequate beyond 2020.

Q: How should future IRPs deal with the range of uncertainty in the future capacity balance?

A: In addition to improving the economic analysis of retirements, as I describe above, the IRPs should consider how the Connecticut utilities might respond if retirements over the next few years are zero, 1,000 MW, or 2,000 MW. The IRPs should also identify the steps that the utilities and state agencies should take to facilitate appropriate responses if retirements and other factors result in rapid increases in forward capacity prices.

V. Specific Resources

A. Energy Efficiency

Q: In what level of detail should an IRP treat energy-efficiency programs?

A: The IRP should consider the principles and priorities driving the energy-efficiency programs, and the appropriate scope and budget.

In most cases, especially in the restructured market, the IRP will not concern the exact size or location of new generation or retirements, or often even the technology of new generation, which will be determined by the behavior of participants in the ISO-NE markets and bidders in utility RFPs. The IRP appropriately examines generation options on a generic basis, using estimates of typical costs. The review of the IRP should be concerned with the reasonableness of those estimates and the resulting guidance for utility and Department actions in seeking resources. The actual selection of resources, and determination of the optimal amount and type of generation resources, shold be left to the review of the specific procurements (as in Dockets 05-07-14PH2, 07-08-24, 08-01-01, and the long-term contracts for Standard Service being considered in Docket 06-01-08).

Similarly, the IRP should be concerned with the energy-efficiency programs at the portfolio level, using reasonable estimates of potential savings and costs rather than the detailed design of the programs. The review of energy-efficiency programs in the IRP should focus on whether the magnitude, timing, and costs of the potential resources are reasonably estimated, and whether the proposed resource expenditures best promote the minimization of total costs, compared to larger, smaller, or differently structured programs. Guidance from the Department may also be useful on broad policy issues, such as cost-benefit tests, trade-offs between lower bills and higher rates, and priority concerns (by customer class or load segment).

Q: Either at the policy level in the IRP, or in the review of the CLM programs, how should the Department determine the amount of energy efficiency to be pursued?

A: The most important consideration is cost-effectiveness, as I discuss in Section III, above. Mr. Plunkett will testify on approaches to improving the cost-effectiveness of energy-efficiency programs. In addition, the Department must consider the feasible rate at which energy-efficiency costs can be recovered through rates, as well as inter-class equity and similar social considerations.

B. Peakers

Q: Does the IRP consider the acquisition or encouragement of additional peaking capacity in Connecticut?

A: No. Brattle chose not to model the benefits of peakers in reducing uplift, LFRM costs or the allocation of LFRM charges to Connecticut.

Q: How should future IRPs treat peaking capacity?

A: First, the utilities and/or the CEAB need to model LFRM pricing and allocation, and uplift costs, perhaps by building on the work done in Docket No. 08-01-01, updated for future LFRM auctions and changes in uplift costs. Second, the IRP should incorporate the effects on the LFRM of the outcome of the ISO's test of demand response as an LFRM resource, including the resulting ISO-NE rules and the amount of demand response that qualifies as LFRM. Third, the IRP should address the effect of transmission changes (the completion of the Southwest Connecticut project and whatever appears likely to materialize from NEEWS) on uplift and locational reserve requirements.

In any case, it seems unlikely that a strong case can be made for acquisition of additional peaker capacity, given the low prices likely in the FCM market, until at least 2010 or 2011, when the first of the Docket 08-01-01 peakers enter service and the elasticity in Connecticut LFRM supply can be directly observed.[20]

C. Demand Response

Q: What level of demand response is proposed in the IRP and the Procurement Plan?

[20]Should any of the peakers approved in Docket 08-01-01 be canceled, the utilities should use the next IRP to consider the potential benefits of procuring additional peakers.

A: The DSM-focus case of the IRP, endorsed by the Procurement Plan, proposes to implement demand response "more rapidly than efficiency" (IRP p. 33), increasing Connecticut demand response over the reference case by 128 MW by 2013 (IRP, Tables D.3 and D.4).[21]

Q: How did the utilities and CEAB determine that the additional demand response would be cost-effective?

A: That information does not appear to be available in the documents I have reviewed.

Q: What are the benefits of demand-response programs?

A: Demand response provides transitional capacity payments and then FCM revenues to the demand-response provider, and would (in some years) tend to reduce FCM prices. If some demand response eventually qualifies as providing operating reserves, those projects would receive LFRM or other reserve revenues, and would tend to reduce LFRM prices and uplift costs.[22] If the demand response can be dispatched in response to T&D contingencies, it may also have some benefits in deferring utility investments.

As I discuss above in Section IV.A.2, unless additional steam plants retire FCM prices will fall until about 2015, and increased FCM supply would have no effect on FCM prices. Hence, other than small payments to participants by the ISO, the benefits of demand-response will be limited to projects that can serve the LFRM (if any can do so) or T&D deferral.

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[21]Somehow, the DSM-focus case assumes 22 MW of additional demand response in 2007, which was prior to any possible effect of the choice of case in the IRP.

[22]Recognizing "the frequency of the [reserve activation] events and their timing," the utilities "estimate that between 2% and 5% of the participants in the demand response program will choose to also participate in the LFRM" (IR OCC-24).

Q: Given the limited value of demand response over the next several years, how should the utilities be supporting demand response, if at all?

A: The utilities should not be spending substantial ratepayer funds for demand response that will provide only FCM benefits. The utilities currently "provide enrolling customers with the ISO-NE-required internet-based communications system. CL&P and UI also provide enrolling customers with a one-time set-up incentive of $400–$1,500 to cover costs for data, phone, or metering connections" (Conservation and Load Management Plan 2008, CL&P and UI, Docket 07-10-03, October 1, 2007, p. 189). I recommend that those incentives be suspended for FCM-only projects until the forward capacity price appears likely to rise above the floor price. For new FCM-only demand-response projects, utility assistance should be limited to administrative functions, to simplify customer interaction with the ISO.

If the ISO finds that demand response can provide reserves, future IRPs should estimate the effect of additional reserves on Connecticut's allocation of LFRM costs. The market payments for demand response that can clear in the LFRM should be very generous, but there may be some incremental demand-response applications that could reduce LFRM costs to all Connecticut customers but would require some utility support, such as a multi-year forward contract. If the utilities identify such incremental demand-response opportunities, they should bring that information to the attention of the Department and propose responses in future IRPs.

The utilities should also evaluate the extent to which there are major T&D investments that could be deferred, and areas in which substandard T&D reliability could be improved, by local demand response. As they identify those opportunities, the utilities should pursue opportunities for including T&D

conditions in the criteria under which loads can be interrupted both for existing demand-response capability and potential new demand-response installations.

D. Nuclear Costs

Q: Are the assumptions in the IRP regarding nuclear costs realistic?

A: No. Brattle makes the following assumptions:

- A nuclear unit not yet proposed could be built in Connecticut by 2015.[23] The utilities that have filed applications with the NRC and/or state regulators—Georgia Power, FPL, and Progress Energy—are aiming for in-service dates later than 2015.[24]
- An "average" national overnight capital cost of $3,481/kW, adjusted up by 16% for location in Connecticut.
- A short construction period, resulting in just 12.1% real AFUDC. With seven years of inflation to 2015, the nuclear unit considered in the IRP would cost $4,576/kW at a typical site, and $5,308/kW in Connecticut. The filed proposals have total cost in the $6,000–$6,500/kW range, for such relatively low-cost locations as Georgia and Florida.
- "Average" national O&M of $73.7/kW-year kW (adjusted up by 40% for location in Connecticut), while the nuclear plants that report costs to FERC had 2007 O&M of over $100/kW-year, plus property taxes, insurance, and

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[23]A proposal to ISO-NE, cosponsored by UI, opines that the "probability of new NE nuclear/coal plant appears low." UI-CMEEC-MMWEC Request for Economic Study, Planning Advisory Committee, April 30, 2008, p. 3.

[24]Georgia Power has projected in-service dates for Vogtle 3 and 4of 2016 and 2017, Progress Energy Florida has projected 2016 and 2017 for Levy County 1 and 2, and Florida Power & Light has projected in-service dates for Turkey Point 6 and 7 of 2018 and 2020.

general and administrative charges, which probably adds 30% or more to the FERC O&M costs.

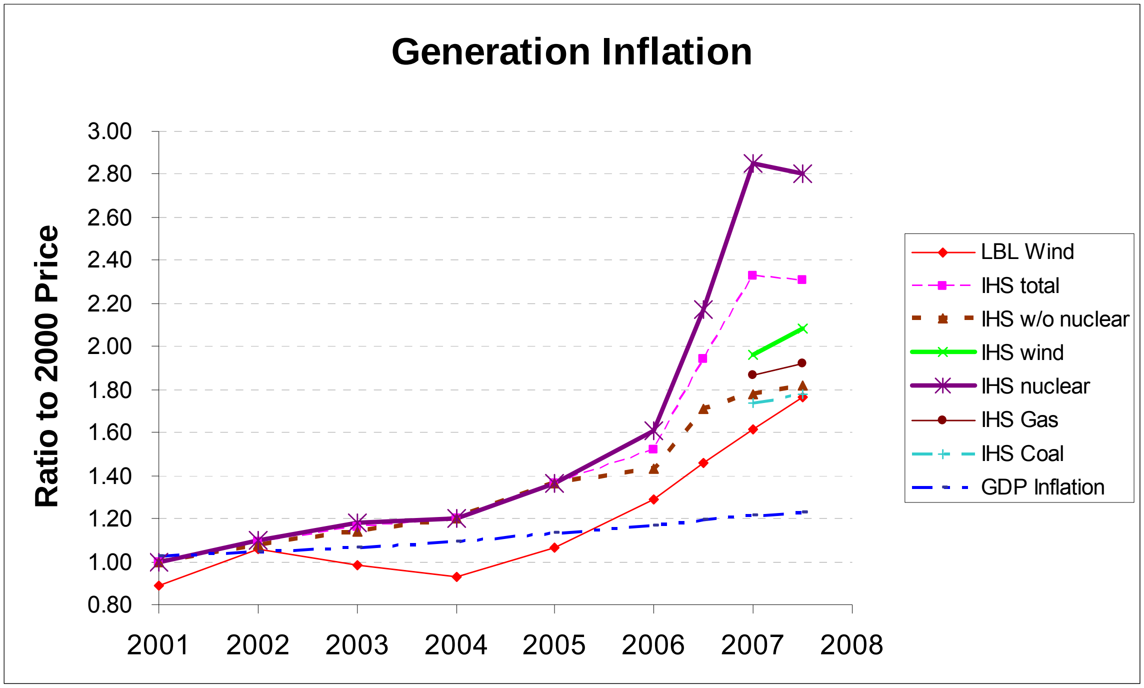
- No post-operation capital additions, which vary widely but average about \$20/kW-year for existing nuclear units.
- The same cost of capital for nuclear as for combined-cycle units, despite the much higher risk of building, owning, and operating a nuclear unit under a fixed-price performance-based contract.
- A 90% capacity factor, which is very optimistic. The average capacity factor of US nuclear units is currently close to 90%, but that took more than a decade of improvement from the 55%–65% range typical of the 1970s and 1980s.[25] Experience suggests that the new reactor designs currently proposed may require many years to reach mature capacity factors.

Q: Have nuclear costs been rising?

A: Yes. Nuclear costs have risen 180% since 2000, most of that since 2004, about twice the increase of gas-fired generation or wind. The following graph summarizes escalation in the costs of various types of generation from the IHS-CERA Power Capital Costs Index with Lawrence Berkeley Lab's estimates of escalation in wind costs and with GDP inflation.

[25]The high average capacity factors also reflect the fact that many plants have low nominal capacities, reflecting regulatory limits that have been relaxed.

Figure 1: Escalation in Generation Prices



Q: What is the source of Brattle's assumptions regarding nuclear costs?

A: Brattle's workpapers (in IR OCC-25) refer to a 2003 study (Ansolabehere et al. 2003), but the assumptions used in Brattle's computations are very different from those of the cited study.[26] The study uses 75%–85% capacity factors, while Brattle uses 90%; the study assumes an overnight capital cost of $2,340/kW, while Brattle uses a more-reasonable if still low $3,500/kW.[27] Ansolabehere et al. assume that non-fuel O&M costs could be reduced 25% "compared to the recent operating cost experience of the average nuclear plant operating in the U.S. in the last few years....because we expect that operators of new nuclear plants in a competitive wholesale electricity market environment will have to

[26]Ansolabehere, Stephen, John Deutch, Michael Driscoll, Paul Gray, John Holdren, Paul Joskow, Richard Lester, Ernest Monz, Neil Todreas, Eric Beckjors, Nathan Hottle, Christopher Jones, and Etienne Parent. 2003. "The Future of Nuclear Power: An Interdisciplinary MIT Study." Cambridge, Mass.: Massachusetts Institute of Technology.

[27]The source cited for the Brattle capital cost is "TBG.."

demonstrate better than average performance to investors" (pp. 38–39). In other words, O&M will go down because it must.

Q: How should future IRPs analyze potential nuclear additions?

A: The cost and performance operation should be more realistically grounded in current data and estimates.

E. Renewables

Q: How are renewables treated in the IRP?

A: Brattle assumes that insufficient renewables will be developed to meet the RPS requirements, so REC prices in Connecticut (and most other states) would remain at the alternative compliance payment (ACP) rates.

Q: How are renewables treated in the Supplement?

A: Based on assumptions provided by La Capra, Brattle evaluated a case in which sufficient renewables are added in New England, New York, Quebec, and New Brunswick to meet the New England aggregate RPS requirements. La Capra estimates that meeting New England renewable requirements would require 10,741 GWh of additional annual renewable energy, above the level available in 2008. La Capra's incremental renewable supply plan for 2018 includes small amounts of hydro and landfill gas, 364 MW of clean biomass (retrofitting existing high-emission biomass to meet RPS requirements and repowering small coal plants to burn biomass), 1,282 MW of wind in New England, 249 MW of wind in New York, and 1,006 of wind in Quebec and New Brunswick. The carrying costs of the plants are estimated assuming that they have contracts that cover their costs, and that each plant would sell its power to utilities at those costs. Brattle assumed that the Canadian wind would require over $2.5 billion in transmission lines (IR OCC-33). That estimate was based on a transmission proposal to ISO-NE cosponsored by UI (IR OCC-33).[28] The $2.5-billion estimate in that proposal was just for a line from New Brunswick to Norwalk; adding transmission to Quebec would almost certainly add to the cost.[29]

Using these assumptions, Brattle estimates that the net cost of meeting the New England RPS standards would average $40/MWh in 2008 dollars, below the alternative compliance payment (ACP) in Connecticut (which does not escalate, and would fall to about $44/MWh in 2008 dollars by 2018) and well below the $59/MWh escalating ACP in Massachusetts, Rhode Island, New Hampshire and Maine. The Supplement treats the difference between the ACP charge and the cost of renewables as a reduction in costs.

Q: Is this analysis likely to be a reliable gauge to future REC prices or appropriate procurement policies for meeting RPS goals?

A: Probably not. Reliably modeling the renewables market would be a tall order for any analysis. The renewables analysis in the Supplement offers a plausible scenario in which the New England states can meet their rapidly-expanding RPS goals without relying on alternative compliance payments. Whether the eventual outcome approximates that shown in Table 1 of the Supplement depends on such factors as

- the actual availability of land for wind development,
- willingness of various authorities to permit wind plants,
- actual wind speeds,

[28]UI-CMEEC-MMWEC Request for Economic Study, Planning Advisory Committee, April 30, 2008.

[29]Brattle is not clear on amount of transmission from either of the Canadian sources (Quebec or New Brunswick) to any of the three New England destinations (New Hampshire, Boston and Norwalk) (IR OCC-39). That information would need to be incorporated in any cost estimate.

- the costs of equipment and development,
- the costs of transmission (or for very small projects, distribution) connections,[30]
- availability of biomass fuel.

There is limited prior experience in comparable resource development to guide the analysis.

Q: In addition to the inherent difficulties of modeling the renewables market, do you have concerns about the renewables modeling in the Supplement?

A: I have several such concerns. First, the Supplement offers rather high-level summaries of La Capra's results, without any detail on the derivation of the costs and potential for various resources, or the selection of the least-cost mix. La Capra provided some of this information on discovery, but more of the data should be available in the next IRP.

Second, I cannot reproduce La Capra's selection of resources from its spreadsheet provided in IR OCC-31. The next IRP should show how the supply curve for renewable resources was compared to the demand for renewables.

Third, Brattle's assumption that each plant will sell power and RECs at cost is implausible. La Capra estimates that some entire categories of generation would have total costs as much as a third less than their energy and capacity revenues, yet Brattle assumes that each plant in that group will sell to the utilities at cost, leaving on the table all the potential REC revenues and a large portion of all other revenues.

[30]La Capra estimated wind potential based on distance to transmission lines, but the existence of a transmission line does not guarantee that it the line or associated substations are able to accommodate additional generation.

Fourth, there is a mismatch between La Capra, who selected 1,006 MW of Canadian wind on the assumption that existing transmission would be adequate, and Brattle, who assumed that over $2.5 billion in transmission would be needed to bring these resources from Canada to New Hampshire, Boston and Connecticut.[31] With the additional transmission costs, the cost of the Canadian resources, net of energy and capacity value, would be about $100/MWh, and the Canadian resources would not be competitive with New England renewable resources. Fortunately, there is already more wind capacity in the New England interconnection queue than the total wind capacity La Capra assumed for 2018 from New England, New York and Canada (IR OCC-38). Perhaps the Canadian renewables can be delivered without transmission; perhaps they would require $2.5 billion in transmission interties (in which case they should be rejected in favor of less-expensive domestic renewables). In either case, the costs of meeting the New England RPS goals—given La Capra's other assumptions—would be less than the $40/MWh reported by Brattle.

The corrected analysis appears to indicate that major new transmission is not needed to meet RPS goals, and the renewable imports would not justify construction of the massive transmission system suggested in the Supplement. Additional transmission capacity between New England and Canada may be cost-effective at some point, but not for delivering wind resources with costs very similar to those of New England resources. Certainly, sizing transmission at a cost of over $2,500/kW to carry the peak generation of the wind plants, but receiving energy at just a 34% capacity factor, would be a poor planning

[31]It is not clear whether the error was due to an inconsistency in La Capra's request, Brattle's misunderstanding of La Capra's assumptions, Brattle's decision that La Capra is wrong regarding the availability of transmission on the existing interconnections, or UI's desire that its proposed transmission project be blessed in the IRP process.

decision. Connecticut consumers would likely be much better off with a smaller transmission link, selling any excess wind energy in the high-generation hours into the Canadian market, purchasing additional energy to firm up the deliveries, and/or purchasing balancing services from Hydro Quebec's large hydro storage capacity.[32]

Fifth, it would be useful to know the marginal renewable cost—which would set REC prices—as well as the average price. I believe that information would be easy to extract from La Capra's model, although the carrying cost would need to be adjusted to reflect merchant financing.

Sixth, the analysis does not compare the renewable supply or REC prices relying on the existing markets with situations in which various amounts of renewables are financed through long-term utility contracts. The decision of whether, and to what extent, utilities should promote construction of new renewables by signing long-term contracts is of considerable current interest in Connecticut and other New England states.[33]

Q: What conclusions should the Department draw from the renewables analysis in the IRP and Supplement?

A: Other than that the future of renewables in New England is highly uncertain and deserves more analysis and scrutiny, the Department should not rely much on the renewables analysis. Sufficient renewable potential to meet regional RPS requirements may be achievable at prices below the ACPs solely within New

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[32] Brattle did not consider any of these more rational uses of the very expensive transmission it incorporated in the renewables case (IR OCC-37).

[33] The Massachusetts Green Communities Act requires utilities to solicit "cost-effective long-term contracts to facilitate the financing of renewable energy generation within the jurisdictional boundaries of the commonwealth, including state waters, or in adjacent federal waters." Chapter 169 of the Acts of 2008, Section 83.

England, or with imports from New York, or perhaps only with imports from Canada, which may or may not require expensive transmission upgrades. Achieving that level of renewable energy may or may not require long-term contracts from utilities or state agencies. And the costs of the RECs may be $15/MWh or $50/MWh.

No precipitous actions should be taken in response to these studies.

VI. Procurement and Cost Recovery

Q: If the Department determines that the utilities should support the development of renewable energy through long-term contracts, how might those contracts be structured?

A: The market value of RECs will tend to vary inversely with the market price of energy and (to a much lesser extent) capacity, as recognized in La Capra's analysis. For example, suppose that renewables cost $130/MWh if developed for the short- term merchant market, and $110/MWh if developed entirely under contract, and that the expected value of energy and capacity for the renewables is $80/MWh. Under these circumstances, the utilities may be able to contract for the RECs alone at $30/MWh (i.e., $110/MWh–$80/MWh), if another party contracts for the power output of the renewables. The market price for RECs would then be $50/MWh (i.e., $130/MWh–$80/MWh). If the actual power and REC prices turn out to be close to those expected at the time of contracting, ratepayers would save $20/MWh with either the REC-only contract or the full-output contract.

However, if actual power prices are much higher, such as $110/MWh, the market price for RECs would fall to $20/MWh. With the REC-only contract, ratepayers would pay both the higher contract REC price and the higher market power costs, for a total price of $140/MWh. With the full-output contract, ratepayers would pay the $110/MWh contract price.

Hence, long-term contracts for new renewables should include all products from the plants (RECs, energy, any environmental credits, and generally capacity as well), to maximize the price stability for consumers.

Q: How should the costs of resources acquired through the IRP process be recovered?

A: The IRP should be designed to minimize the costs to all Connecticut consumers, regardless of whether they receive generation services from the utility's Standard Service or SLR service or from competitive suppliers. Hence, the costs of the IRP, and most of the resources that may be acquired in response to the IRP, should be recovered from all customers, through non-bypassable charges.

Q: How should energy-efficiency costs be recovered?

A: To reduce the near-term effects of energy-efficiency spending on customers as the program ramps up, the Department may find it useful to amortize recovery of DSM costs over several years. The carrying costs of the energy-efficiency investments may be reduced by securitization of the associated debt.

In addition, if the distribution on energy-efficiency investments across classes appears to be very different from the distribution of sales across those classes, the Department should consider the recovery of energy-efficiency costs from the rate classes that receive the services for each program.

Neither of these cost-recovery issues need be resolved in this proceeding, but the Department should be aware that these mechanisms exist. In no case should the energy-efficiency programs be reduced from their most beneficial levels due to concerns about the allocation or timing of cost recovery.

Q: Does this conclude your testimony?

A: Yes, at this time. Considering the timing of responses to discovery, I may need to supplement my testimony prior to or at the hearings.