STATE OF CONNECTICUT

BEFORE THE DEPARTMENT OF PUBLIC UTILITY CONTROL

	)	
Review of Energy Independence Act	**)**	**Docket No. 07-04-24**
Capacity Contracts	**)**	
	)	

DIRECT TESTIMONY OF

PAUL CHERNICK AND JONATHAN WALLACH

ON BEHALF OF

THE OFFICE OF CONSUMER COUNSEL

Resource Insight, Inc.

JUNE 29, 2007

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I. Identification and Qualifications

A. Paul Chernick

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 (PBR) and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-JFW-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 two 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

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

- Dockets 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.
- Docket No. 03-07-02, on behalf of AARP, on the distribution investment plan and rates for CL&P.
- Docket No. 03-07-01, on behalf of AARP, on the application of the rate cap to CL&P's transitional standard offer.
- Dockets No. 03-07-01RE1 and 03-07-15RE2, on CL&P and UI requests for incentives for mitigating transitional standard offer costs.
- Docket 05-07-18, on whether capacity contracts impose costs on the electric utilities.
- Docket 06-01-08, on multiple rounds of procurement results and on lessons learned from the procurements.

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

B. Jonathan Wallach

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

A: I am Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional education and experience.

A: I have worked as a consultant to the electric-power industry for more than two decades. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From

1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the last twenty-five years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My professional qualifications are further summarized in Exhibit PLC-JFW-2.

II. Introduction

Q: On whose behalf are you testifying?

A: Our 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 us to review the projects for which London Economics International (LEI) has recommended the Department approve contracts between the projects and the electric utilities (CL&P and UI). We were asked to review LEI's analysis and reach independent judgments regarding the desirability of each proposed project.

Q: What standards are applicable to this question?

A: The recommended contracts were the result of a request for proposals (RFP) pursuant to Section 12 of Public Act 05-01, June Special Session, known as An Act Concerning Energy Independence (the Act). That section lists two sets of standards for reviewing potential contracts:

> The department shall give preference to proposals that (1) result in the greatest aggregate reduction of federally-mandated congestion charges for the period commencing on May 1, 2006, and ending on December 31, 2010, or such later date specified by the department, (2) make efficient use of existing sites and supply infrastructure, and (3) serve the long-term interests of ratepayers. §12(g)

> No contract shall be approved unless the department finds that approval of such contract would (1) result in the lowest reasonable cost of such products and services, (2) increase reliability, and (3) minimize federally-mandated congestion charges to the state over the life of the contract. §12(i)

Q: Are these standards equally important in your analysis?

A: No. We concentrate on standards (1) and (3) of §12 (g) and standards (1) and (3) of §12 (i). We offer a few comments below on LEI's implementation of standard (2) of §12 (g), but do not attempt to re-compute the value of existing sites and supply infrastructure. We agree with LEI's conclusion that all of the proposed resources will increase reliability, and hence have no other comments on standard (2) of §12 (i).

A. London Economics International's Analysis

Q: What are your sources of information regarding LEI's analysis of the bids for various projects?

A: Our review is based on several sources of data, including the following five documents produced by LEI for the Department:

- "Report on the Electricity Sector Needs of Connecticut, 2007–2021," revised August 25, 2006 (the Needs Assessment),
- "Recommendations on Selection of Projects in the 2006 Connecticut RFP," May 3, 2007 (the Report).
- The confidential version of the Report (the Confidential Report), May 7, 2007, which includes additional non-confidential information, as well as confidential bidder information.

- "Technical Meeting: Modeling, Cost-Benefit Analysis, and Selection of Winning Bids in Docket 07-04-24 Phase II," the public handouts from the first technical meeting (the Technical Meeting Handouts).
- "Technical Meeting: Modeling, Cost-Benefit Analysis, and Selection of Winning Bids in Docket 07-04-24 Phase II, Appendix," additional materials (some of which are confidential) from the first technical meeting (the Technical Meeting Appendix).

In addition, we relied on LEI's responses to discovery questions from the OCC.[1]

We also attended two technical meetings with London Economics at the Department's offices, on May 30 and June 14, during which LEI showed us spreadsheet pages that were not otherwise provided and where we questioned LEI about the modeling process. We refer to the transcripts from those meetings in this testimony.

Q: Did LEI provide OCC a complete set of discovery responses?

A: No. Some of LEI's responses came in so recently that careful analysis of the materials was not possible, and some LEI responses have not yet been received at all. The Office of Consumer Counsel asked us to prepare this testimony on the basis of the information in hand, because the agency is mindful of the Department's announced schedule for this docket. We will review all further LEI materials that become available, and update our testimony as appropriate.

Q: Please summarize the LEI's methodology for evaluating project proposals.

A: Each bid specified (among other things) the project technology (combined-cycle, peaker, demand-response, or energy-efficiency), the amount of capacity

[1]We refer to these responses as "IR OCC-xx," where "xx" is the question number

offered, and the price for that capacity in each year of the contract. Some bids also offered quantities and prices for forward reserves or for an optional energy contract. For each of the three products (capacity, reserves, and energy), the offers were structured as contracts for differences, under which the utilities would pay the bidder the bid price minus the market price of the product.

The LEI analysis of the bids can be broken into the following steps:[2]

- Prescreening, in which LEI computed the present value of bid contract costs for each project and divided that value by the bid capacity. LEI then set a threshold value per kilowatt for each technology and screened out all projects with bid prices above the threshold. Fifteen projects passed prescreening.
- Construction of 29 portfolios, each consisting of two to six of the fifteen projects that passed prescreening. All but three of these modeled portfolios include a combined-cycle unit.
- Definition of nine “baseline” scenarios of generic capacity additions, each of which specifies a set of annual fuel prices, Connecticut and New England loads, supply additions, and retirements. LEI assumes a probability weight for each of these nine scenarios.
- Estimation of baseline market prices for energy, forward capacity and forward reserves for each baseline scenario.[3]

[2]London Economics’ analysis is described in more detail in the Report and in discovery.

[3]LEI frequently refers to the three power-supply products using the terms that ISO-NE uses: Locational Marginal Price (LMP), Forward Capacity Market (FCM), and Locational Forward Reserve Market (LFRM).

- Re-estimation of market prices for each baseline scenario with the addition of one of the fifteen individual projects or one of the 29 portfolios to the baseline scenario.
- Economic evaluation of each of the individual projects or portfolios, based on the discounted difference between annual costs and benefits. In LEI's analysis, "costs" are defined as contract payments less the market value of the contract capacity.[4] LEI defines "benefits" as the reduction in costs to Connecticut load due to the decrease in market prices resulting from addition of the individual project or portfolio to a baseline scenario.[5] This evaluation, including weighting of the results for the nine scenarios, is conducted in LEI's spreadsheet Bid Evaluation Model (BEM).
- Assignment of values to each project and portfolio for other, non-economic factors.

London Economics ultimately selected Portfolio 89, comprising the following projects:

- Project D (a/k/a. Project 358), a 5-MW energy-efficiency project proposed by Ameresco.
- Project E (Project 409), a 620-MW combined-cycle plant proposed by Kleen Energy.

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[4]The market value of the contract in each year is determined as revenues from the forward capacity market – derived as the product of the forward capacity guaranteed under the contract and the forward-capacity market price – plus, for contracts with an LFRM component, LFRM revenues – derived as the product of the contract forward-reserve capacity and the forward-reserve market price.

[5]In other words, benefits are determined by the difference between market prices for the baseline scenario and market prices resulting from the addition of the RFP project or portfolio to the baseline.

- Project O (Project 851), a 66-MW peaking plant proposed by Waterside Power.
- Project R (Project 993), a 96-MW peaking plant proposed by Waterbury Generation.

B. Summary Assessment of London Economics International's Analysis

Q: Please summarize your assessment of LEI's analysis.

A: From our review of LEI's work products and responses to OCC discovery, London Economics' market-price models appear to accurately and comprehensively simulate market rules and operating procedures in each product market, and to reasonably simulate pricing interactions among these product markets.

However, LEI's analysis suffers from a number of methodological errors. As a result, most of the projects that LEI recommends do not appear to be cost-effective.

Q: Please describe the most critical methodological errors in LEI's analysis.

A: While there are several problems in LEI's analysis, three methodological errors apparently led LEI to erroneously recommend approval of uneconomic bids. These three errors were:

- failing to address identified resource needs;
- implausibly assuming that the addition of capacity from request-for-proposals (RFP) projects would not affect the quantity or timing of other supply additions and retirements; and
- relying on unrealistic baseline scenarios and scenario weightings for modeling project impacts.

Q: How did LEI's analysis fail to address identified needs in Connecticut?

A: The RFP was mandated by the General Assembly to improve reliability and reduce federally mandated congestions costs (FMCC), which the General Assembly defines as including "locational marginal pricing, locational installed capacity payments,… and reliability must-run contracts" (Conn. Gen. Stat. §16-1(a)(41)).[6] The Needs Assessment found that locational installed capacity would be sufficient in Connecticut until 2018, but that about 625 MW of quick-start peakers would be needed to meet Connecticut's requirement for forward reserves, both to ensure reliability and to reduce costs (Needs Assessment at 12). In the bid evaluations, LEI increased the projected base-case locational-forward-reserve-market (LFRM) shortfall to 650 MW in 2010, rising to 681 MW in 2012.[7] Due to the structure of the ISO's LFRM market, additions of less than the 650 MW of required forward reserves could actually increase FMCC.

We therefore expected that the evaluation of the RFP bids would focus on procuring forward reserves, determining whether the critical 650 MW of forward reserves could be developed economically, quantifying the effect of project proposals on energy prices in Connecticut, and determining whether various combinations of resources (combined with the start of the forward capacity market in 2010) would eliminate the need for the Connecticut reliability-must-run (RMR) contracts that will be in effect until June 2010.

LEI sidesteps three of these four logical priorities in its evaluation of proposals. Rather than evaluating whether the proposed projects could economically contribute to satisfy the 650 MW reserve shortfall, LEI simply

[6]The Act also allows the Department to take other factors into consideration, but improving reliability and reducing FMCCs appear to be the central purposes of this portion of the Act.

[7]The shortfalls are 20–30 MW larger in the high-growth cases.

assumes that this need is met with the addition of 700 MW of generic combustion turbines in Connecticut in 2010. Consequently, the evaluation never considers the technical or economic feasibility of bringing on 650 MW of LFRM, or the effects of achieving only part of that goal. Instead, the analysis assumes the need for forward reserves is already met by other market additions.[8] Nor did the evaluation attempt to determine whether the need for the RMR contracts would be eliminated by any particular combination of projects. LEI did estimate the effects of various projects on Connecticut market energy prices.[9] But the most important factor in LEI's evaluation turned out to be its estimates of the effects of the RFP projects on New England regional capacity prices, not on Connecticut congestion.

Q: Why do you say that effects on New England regional capacity prices were the most important factor in LEI's evaluation?

A: This is evident in LEI's results. For example, on page 56 of the Report, LEI shows the largest category of benefits for Portfolio 89 to be the capacity-price benefit of $441 million. Since Connecticut capacity prices are the same as New England prices in all of LEI's scenarios, these putative benefits are all from reductions in New England-wide prices. In contrast, LEI reports that Project 89 would have energy-price benefits of $419 million, of which a portion is due to

[8] London Economics has justified its treatment of LFRM costs by noting that its projections of LFRM costs are lower than its projections of energy and FCM costs to load. While that observation is correct, it is also likely that Connecticut can have a much larger proportional effect on the LFRM price. LEI estimates (perhaps unrealistically) that adding 700 MW of peakers would reduce the LFRM price by over 60%. In contrast, adding nearly 800 MW of Portfolio 89 only reduces energy prices about 1%.

[9] These estimates suffered from some serious modeling problems, as described in Section IV.A of this testimony.

reductions in congestion and a portion is due to general price reductions across New England.[10]

Q: With regard to the second serious error you identify, how did LEI assume the RFP projects would affect the addition of other future power plants?

A: London Economics assumed that the type, quantity, and timing of generic additions assumed in the baseline scenarios would not change with the addition of an RFP project. As a result, LEI's analysis overstates the likely amount of *net* capacity additions and, consequently, overstates the reduction in market prices due the addition of an RFP project.

Q: Is LEI's assumption reasonable?

A: No. Whatever rules one might use to estimate the amount of capacity that would be added without the RFP projects, applying those rules with the RFP projects included should result in reduced generic additions. When LEI modeled the New England electricity markets without any RFP projects, LEI assumed that the market would add just enough capacity to meet the ISO's requirements, or slightly more.[11] For example, in the base case, LEI expected the capacity market to be short by 756 MW in 2011, and added 850 MW of new generic resources to meet that need. When LEI added some RFP projects, it ignored its own expansion rule: with the addition of Project E, for example, New England would need only 136 MW more in 2011, but LEI still added 850 MW of new generic

[10] From IR OCC-94, 75% of the energy generated by Portfolio 89 in 2011 would reduce the output of generation outside Connecticut, indicating that a significant share of the energy benefits are from pool-wide price reductions, not reduced congestion. Over time, a higher percentage of Portfolio 89's energy reduces generation in Connecticut, but on average over 2011–2021 less than half of the energy backs down Connecticut generation.

[11] Since the size of power plants do not exactly match the need, LEI usually added a little more capacity than would be needed.

resources. It is unrealistic and unreasonable to assume that capacity is added under one set of rules without the RFP projects and under a different set of rules with the projects included. The excess capacity that LEI forces into the market in the cases with RFP projects unrealistically reduces market capacity and energy prices, creating illusory market-price benefits that LEI attributes to the projects.

This unrealistic treatment of capacity additions reduces market prices so much that market revenues would not cover the costs LEI estimates for some of the generic resources. For example, with the addition of LEI's preferred Portfolio 89, LEI's own results show 1,150 MW of capacity additions (including 300 MW in Connecticut) not earning enough revenue to cover their costs in the base case scenario (i.e., Scenario 2).[12]. Yet LEI assumes those plants would be built and would thereby reduce market prices.

Q: What is the effect of this second major error on LEI's recommendation?

A: The manner in which London Economics treated capacity additions grossly overstates the benefit of RFP projects in reducing market energy and capacity prices. If this error is corrected, *none* of the recommended RFP projects reduce costs to ratepayers.

Q: Are you suggesting that the addition of an RFP project will not have any impact on market prices?

A: No. In fact, in other proceedings, we have recommended procurement of long-term contracts for the purposes of reducing and stabilizing market prices. However, in this case, LEI appears to have dramatically overstated market-price

[12] In the low-load Scenario 4, the non-cleared generic capacity rises above 3,800 MW; in other scenarios, non-cleared generic capacity varies from zero to 1,150 MW.

benefits with its flawed assumption that the quantity and timing of generic additions is invariant following the addition of RFP projects.

Q: Please elaborate on the third major error you identified with LEI's analysis: the unrealistic and implausible weighting of baseline scenarios.

A: The results of LEI's evaluation are heavily influenced by the high weights given to unlikely scenarios. In particular, LEI assigned a combined 35% weight to three scenarios (Scenarios 5, 8, and 9) in which New England capacity remains significantly less than required levels for eight to ten years. In Scenarios 8 and 9 (which LEI gives a 25% combined probability), LEI assumes that New England capacity actually would be less than peak load, resulting in negative reserve margins for seven years.

Q: What is the effect of this third major error on LEI's analysis?

A: It overstates the benefits from the recommended RFP projects, as averaged across the baseline scenarios, by assigning high weights to implausible scenarios that generate relatively large benefits.

Q: What is the result of correcting these major errors?

A: Correcting these errors results in Portfolio 89 no longer being cost-effective. The market-price reductions that LEI claims as benefits of the contracts are grossly exaggerated, and the net benefit of Portfolio 89 is likely to be negative, raising total costs to Connecticut customers. In other words, under a corrected evaluation, Portfolio 89 fails the statutory standard that the RFP contracts "minimize federally mandated congestion charges" and "result in the lowest reasonable cost of such products and services." The same is true for most other portfolios and individual projects, particularly Projects E and R.[13]

[13]Project O is a closer case, as discussed in the next section.

Q: Are there other problems in LEI's analysis, beyond these three major errors?

A: Yes, we have identified the following problems, most of which we discuss further in later sections:

- London Economics miscalculated net contract costs in certain years, by failing to subtract the market value of the contract capacity from the contract payments (Section IV.D).[14]
- London Economics recognized that its energy model randomly over- and under-estimates the effect of project additions on energy prices, but its attempt to correct that problem understates the benefits of small and peaking projects and results in illusory differences between portfolios (Section IV.A).
- The computation of existing generators' fixed costs—used to estimate generators' bids in the forward capacity market and for evaluating the economics of retirement decisions—appears flawed (Sections III.B.2 and IV.B).
- In addition to sidestepping the major LFRM issue (getting about 650 MW of peaking units constructed in Connecticut), LEI's modeling of LFRM prices appears arbitrary (Section IV.C).
- The methods LEI used to value of some of the "other factors" for each project are unreasonably sensitive to the characteristics of other projects, including non-viable proposals.

[14]In IR OCC-110 and IR OCC-111, London Economics acknowledges this error in its calculations. These responses were marked as "confidential", although they apparently contain no materials covered by the protective order. Due to the confidential designation of these responses, we cannot reveal any more information about LEI's explanation at this point in time.

- LEI's approach to screening energy-efficiency projects does not comply with the requirements of the Act.

C. Recommendations

Q: How should the Department dispose of the four contracts recommended by LEI?

A: The Department should reject the proposed contracts for Project D (Ameresco), Project E (Kleen) and Project R (Waterbury), and approve the proposed contract for Project O (Waterside).

Q: Why should the Department reject the proposed contract for Project D (the 5-MW energy efficiency project)?

A: London Economics did not request, and Ameresco did not offer, enough information to determine whether Project D would

- undermine the existing utility-administered energy-efficiency programs;
- overcharge customers for participation in the program, increasing total costs to Connecticut energy consumers;[15]
- skim off the fast, cheap and easily-measured efficiency opportunities, rather than comprehensively capturing savings from treated systems; or
- leave the treated buildings with new mid-efficiency equipment that must be replaced to reach the efficiency levels of the utility-administered programs.[16]

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[15]LEI recognizes that Ameresco would charge the participants. "At the individual ratepayer level, some of the energy savings are offset by the cost of implementation" (Report, at 24).

[16]IR OCC-15(f) asked LEI to explain how it "determined the fraction of the proposed energy-efficiency measures which would have occurred without the RFP due to EE Programs, efficiency standards, routine replacement, and/or higher electric prices, and the net benefit of the proposal

There is nothing in the proposed contract that would assure that Project D would "result in the lowest reasonable cost of such products and services." If Ameresco maximizes its own profit from the contract, it is unlikely to produce significant benefits for Connecticut ratepayers. Without more information and greater oversight, such as that provided by the Energy Conservation Management Board ("ECMB") with respect to the C&LM fund, it is impossible to judge whether this project is more cost-effective than conservation projects overseen by the ECMB.

Q: Why should the Department reject the proposed contract for Project E (the 620-MW combined-cycle plant)?

A: The cost of the proposed contract for Project E would be roughly twice the contract's market value, depending on the baseline scenario. This project's cost is so far above the market value received in return that it cannot be considered to meet the first standard found in the Act, § 12(i), requiring the contract to result in the "lowest reasonable cost" for the project in question. Ratepayers would be net losers from the contract, even under LEI's most extreme projections of market prices. Project E appears to be cost-effective in LEI's analysis only because LEI assumes that the plant will have massive benefits in reduced market capacity and energy prices, especially in scenarios with prolonged shortages of capacity. Those estimates of benefits are grossly overstated, since they depend on the implausible assumptions that: (1) adding a large combined-cycle plant would have no effect on the additions of generic resources or retirements of existing resources; and (2) the shortage scenarios have significant probabilities.

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accounting for only the incremental savings due to the proposed program." LEI's response did not provide any of this information.

Project E's bid price is much higher than LEI's estimate of the cost of new combined-cycle plants in Connecticut. The Kleen plant is among the farthest along in the ISO interconnection queue. If its true cost is competitive with the costs of other new plants, it is among the units most likely to be built in response to the FCM, and ratepayers will receive the market-price benefits from this project without the massive subsidy requested under the contract. If its cost is comparable to its bid price, and LEI's forecast of market prices approximates reality, Project E's contract would be a large net loss to ratepayers.

Q: Why should the Department reject the proposed contract for Project R (the 96-MW peaking plant)?

A: As with Project E, Project R's proposed contract is too expensive compared to the market prices of the capacity delivered under the contract. The cost ratios are more reasonable for Project R: the contract requires a payment of $1.20 to $1.80 per dollar of market value. Still, Project R passes LEI's economic screening only because LEI's simulation of the forward capacity market overstates the reduction in market prices due to the addition of Project R.

Q: Why should the Department approve the contract for Project O (the 66-MW peaking plant)?

A: Unlike Projects E and R, the market revenues from Project O almost cover the contract costs in LEI's base case, and more than cover the contract costs in the scenario with low fuel prices. Forward-capacity prices even modestly higher than LEI's forecast (which we think is on the low side) would result in Project O being a net benefit to ratepayers, even if the project does not reduce market prices at all. Considering the risk-mitigation benefit of a fixed-price contract and the possibility that the unit would have some energy and LFRM price benefit, we believe that approval of this contract is reasonable.

III. Baseline Scenarios and Resource Additions

A. Scenario Definitions and Weights

Q: What were the baseline scenarios that LEI developed?

A: As summarized in the following table, LEI developed nine baseline scenarios that varied in terms of the type, timing, and quantity of generic resource additions, and in terms of assumed retirement of existing resources.

Scenario	Percent Weight	Scenario Definition
1	7.5%	high fuel
2	30.0%	Base Case
3	2.5%	delay transmission
4	5.0%	low fuel
5	10.0%	delay supply
6	10.0%	low demand, early supply
7	10.0%	low demand, low fuel prices, early supply
8	12.5%	high demand, high fuel prices, late supply
9	12.5%	high demand, late supply

In Scenarios 8 and 9, LEI also included some unspecified costs to reflect "more restrictive environmental regulations".[17]

Q: Are these choices of scenarios reasonable?

A: The choice of scenarios is reasonable in concept, but not in implementation. This selection of scenarios reasonably incorporates the major factors that contribute to uncertainty in market outcomes: fuel prices, demand, and supply timing.

However, LEI's specification of Scenarios 5, 8, and 9 is simply unrealistic. These three scenarios, to which LEI assigns a total 35% probability, assume that

[17] IR OCC-39. This aspect of Scenarios 8 and 9 was not described in the Report. LEI may have assumed other characteristics of various scenarios that it has not revealed.

New England would be short of capacity for ten to twelve years. The maximum deficiencies would be over 2,500 MW for all three Scenarios.

Worse still, in Scenarios 8 and 9, reserve margins would be negative for seven years, with installed resources less than peak load. The capacity deficiencies would exceed 5,000 MW. While various power pools and other large utility systems have occasionally operated with less than the target reserve margins for a year or two, we have not been able to identify any situation in which such a system in North America operated with insufficient capacity for longer periods or operated with a negative reserve margin at all. With a negative reserve margin, the utility would not be able to avoid repeated blackouts.

It is not plausible to assume, as in Scenarios 5, 8, and 9, that the DPUC, other regional regulators, ISO-NE, or state legislators would tolerate inadequate reserves for long, or negative reserves at all, without taking steps to bring on additional central or distributed generation, demand response, energy-efficiency, purchases or other resources.[18] Hence, Scenarios 5, 8, and 9 should not have been included in the analysis.

Q: What was LEI's basis for assuming that these scenarios were plausible, and that they should be assigned such high probabilities?

A: LEI has indicated that the high probabilities for Scenarios 5, 8, and 9 are expressions of risk aversion. (Tr. At 64-65) That explanation would make sense for a plausible emergency, but not for unrealistic long-term deficiencies

[18]For example, the ISO dealt with a looming generation shortage in southwest Connecticut for 2004 with a "Gap RFP," under which it secured demand-response, energy-efficiency, and distributed-generation resources on an emergency basis.

Q: What might be a more reasonable weighting of the scenarios?

A: Scenarios 5, 8 and 9 should be omitted, or given probabilities close to zero. Scenarios 6 and 7 are plausible, but only if balanced by other scenarios featuring higher loads and higher fuel prices.

The remaining four scenarios might be weighted in proportion to the weights LEI gave them, which would be as follows:

Scenario	Percent Weight	Scenario Definition
1	16.7%	high fuel
2	66.7%	Base Case
3	5.6%	delayed transmission
4	11.1%	low fuel

Q: How would this more-reasonable weighting affect LEI's conclusions?

A: For Portfolio 89, the elimination of the implausible scenarios would increase LEI's estimate of costs (contract costs minus market revenue offsets) by $42 million and decrease benefits by $96 million, for a reduction in net benefits of $138 million, or about 27% of LEI's estimate.

B. Baseline Resources

1. Additions

Q: How did LEI determine the amount of existing capacity to be included in its baseline scenarios?

A: London Economics started with the existing generation in the 2006 CELT report, added the net external purchases projected in the CELT through 2015, subtracted a 59-MW "hydro adjustment," added various amounts of demand response in 2006 through 2010, held the amount of demand response constant after 2010, and added 100 MW of Connecticut renewables from Project 100.[19]

Q: What generic additions did LEI assume in the baseline scenarios?

A: IR OCC-35 lists the generic generation capacity that LEI adds in each year for each baseline scenario. In Scenarios 1–4, LEI assumes the addition of 700 MW of peakers in Connecticut in 2010 to meet LFRM requirements, combined-cycle units in the rest of New England in almost every year, and a 300-MW combined-cycle in Connecticut in 2020.

Q: How reasonable is LEI's assumption that 700 MW of peaking units would be added in Connecticut in 2010?

A: London Economics simply assumes that 700 MW of peakers would be added in Connecticut in 2010, to cover the LFRM need of 625 MW identified in the Needs Assessment. Enough peaker capacity has applied for space in the ISO-NE interconnection queue to meet this requirement. The question is: will it be built?

The combined price for FCM and LFRM in Connecticut has been \$14/kW-month since the 2006 auction for winter 2006–2007, and that price has been expected since the LFRM mechanism was established in 2005. Yet this price hasn't brought forth a rush of new capacity for 2007, 2008, or 2009. It is not

[19] Due to incomplete responses from LEI on this topic, we pieced together this explanation, which is drawn from the Report, the BEMs, IR OCC-35, IR OCC-36, the file "Supply Resources-Capacity," and explanations in the Technical Meetings. In response to an early interrogatory, LEI stated that "We included existing capacity and projects that were certain to come online. And the only 'certain projects' included in our modeling are the Project 100 projects, as provided by CT DPUC." (IR OCC-36.) The existing capacity is listed in "Supply Resources-Capacity," along with demand-response capacity ignored in IR OCC-36. All of these documents missed the purchases and the hydro adjustment; we first learned of these during the Technical Meeting on June 14.

clear how effective the lower combined price LEI expects for 2010 (in Scenario 2) will be in bringing this capacity on line.

Q: Would rational developers who agreed with LEI's projections build these Connecticut 2010 peakers?

A: No. LEI assumes that the Connecticut 2010 peakers require $10.6/kW-month levelized over ten years to cover their capital and fixed O&M costs.[20] According to LEI's analysis, revenues in 2010 from the forward-capacity, forward-reserve, and energy markets, net of variable costs, would more than cover the peaking units' fixed costs. However, after 2010, LEI's forecasts that the FCM price will fall substantially, leaving the peaking units nearly two dollars per kilowatt-month short of covering their costs. For the 700 MW of peaking units that LEI anticipates for 2010, the shortfall would be almost $17 million. The resulting revenues would be high enough that the peakers would be cost-effective to keep in service, but not high enough to cover the developers' target equity return. If the developers share LEI's estimate of their costs and LEI's expectation for market prices, they would not build the peakers that LEI expects for 2010.

Q: Does the addition of 700 MW of peakers in Connecticut in the baseline affect project evaluation?

A: Yes. So long as Connecticut is short of LFR capacity, the LFRM price in Connecticut is set by the ISO rules at $14/kW-year. The formula for allocating LFRM costs to load in the various pricing zones is complicated, but the basic effect is that adding less reserves than needed to resolve the shortage in Connecticut increases the amount purchased without reducing the price, thereby resulting in higher costs to Connecticut consumers. LEI's model shows this

[20] After ten years, the debt is paid off and the revenue requirements fall.

effect: in Scenarios 1–4, the projects and portfolios that add LFR in 2008 or 2009 increase LFRM costs to load and show negative LFRM benefits in those years.[21] Once LEI assumes the addition of 700 MW of peakers (all of which contribute forward reserves) in 2010, further additions of reserves reduce the LFRM price, but do not increase the amount purchased, and hence reduce the cost to load. For Scenarios 6 and 7, in which the generic peakers are added in 2009, additional LFR reduces cost to load in 2009; for Scenarios 5, 8, and 9, in which the peakers are delayed, additional LFR increases costs until the peakers are added in 2013 or 2014.

Consequently, the 700-MW assumption is critical in determining whether additional LFR resources increase or decrease costs.

Q: Would additional forward reserves in Connecticut have any value if the generic additions were less than the LFRM shortfall?

A: Adding additional forward reserves through the RFP process would increase market charges to load, so long as the sum of generic and RFP additions is less than the shortfall of 625 to 685 MW (depending on which LEI shortfall analysis one relies on). On the other hand, if a contract with an RFP project includes LFRM payments, the contract price would be offset by the high Connecticut LFRM price. The ISO-NE allocation process for the LFRM costs does not allocate to Connecticut customers all the additional costs due to additional Connecticut forward reserves, so the revenue offset would usually exceed the increase in LFRM costs to Connecticut customers. The difference between the LFRM value of the contract and the allocation of the LFRM costs to Connecticut load is not likely to be large enough to cover the contract cost.

[21]On the other hand, the LFRM revenues offsetting the contract costs are highest in those early years.

Consequently, adding forward reserves through contracts with the utilities is likely to increase total customer costs, so long as forward reserves are less than the local requirement.[22]

Q: What generic resource additions other than the 700 MW of peaking capacity does LEI assume for the baseline scenarios?

A: All of the post-2010 generic additions (and the 2010 additions outside of Connecticut) are assumed to be combined-cycle units. The selection of combined-cycle over peaking technology is driven by LEI's determination of the relative economics of these two plant types.

Q: Are LEI's findings with regard to the relative cost-effectiveness of combined-cycle plant reasonably supported?

A: No. The determination of relative economics is driven largely by LEI's apparent under-estimate of annual fixed costs for new combined-cycle plant relative to those costs for new combustion-turbine plant. In turn, this assumed relatively low cost for combined-cycle units is driven by unreasonable assumptions about financing. Compared to the peaking units (Technical Meeting handouts at 63), LEI expects the combined-cycle units to be financed with

- more debt (60% debt, rather than 40%) and less equity.
- lower-cost debt (9% versus 12% interest rate).
- lower-cost equity (16% versus 21% after-tax return).
- longer debt financing (15 years versus 10).
- longer equity recovery (20 years versus 15).

[22] However, having the additional quick-start reserves would improve reliability.

Cumulatively, the differences reduce LEI's estimate of the annual fixed-charge rate for the combined-cycle units to 14%, compared to the 21% LEI estimates for peakers.[23]

It appears from this assumption of lower financing costs for combined-cycle units that LEI assumes that investment in combined-cycle plant is less risky than investment in peaking plant. Such an assumption is counterintuitive, since a higher percentage of the peakers' revenues come through the forward capacity market, in which the developer can get a five-year fixed-price contract starting three years in the future. In other words, a developer can secure five years of FCM cash flow before starting construction on the peaker. The combined-cycle units, on the other hand, depend more on profits in the energy market to cover their fixed costs. This exposes the developer to swings in both fuel prices and market energy prices, which can only be partially hedged through forward markets.

Q: How does LEI's assumption that all resource additions would be combined-cycle units affect project evaluation?

A: The addition of some 7,000 MW of baseload generation reduces energy prices compared to a mix of peaker and combined-cycle additions.

2. Retirements

Q: How does LEI model the retirement of power plants?

A: As we understand LEI's explanation, only three plants are ever retired in LEI's modeling. Those retirements were selected in two ways.

[23] LEI mentioned at the June 14 technical meeting that the construction costs provided in the Report and in the Technical Meeting handouts do not include AFUDC, so the fixed-charge rates may be somewhat lower than we compute here.

First, in Scenarios 4 and 7, in which LEI assumes low fuel prices, LEI assumes the retirement of the Merrimack and Schiller (528 MW total) coal units in 2014, and the 144-MW Mt. Tom coal plant in 2016. These retirements are part of a sensitivity case, and hence require no specific justification.

Second, LEI claims to have assessed the economics of continued operation of each unit in each year in each baseline scenario. In Scenarios 8 and 9, with strong load growth and delayed entry of generic generation, LEI decided that the 400-MW Newington oil unit would be retired in 2010. LEI attributes the Newington retirement to "more-restrictive environmental regulations…, requiring plants to meet higher environmental standards through the purchase of emission allowances in the open market or the installation of emission control equipments" (IR OCC-39).

These more-restrictive environmental regulations are not listed as features of Scenarios 8 and 9 in the Report; they appear only in LEI's discovery responses. LEI has not explained how a general concept like "more-restrictive environmental regulations" was converted to specific costs. Indeed, elsewhere LEI denies that it considered such costs: "While there could be environmental regulations in the future that require additional capital investments, such speculative capital outlays were beyond the scope of the modeling" (Report at 39).

Even more perplexing, LEI assumes that Newington would be retired in a year when New England would already be 2,300 MW short of the installed-capacity requirements and facing an even larger shortage in future years. In our view, the environmental effects of Newington would have to be nearly catastrophic in order for environmental regulators to order such a shutdown;

considering the reliability effect, the New Hampshire PUC would likely order PSNH to meet the regulatory requirements to keep the lights on.[24]

Q: How did LEI model the economics of continued operation and retirement?

A: The retirement assessment apparently consisted of an evaluation of whether the unit would be expected to "recover its fixed costs over a three year period." (Report at 39) Since LEI assumes each unit bids into the forward capacity auction at the difference between its fixed costs and its other revenues, clearing in the forward capacity auction is essentially the same as recovering fixed costs.[25]

London Economics estimated the fixed costs used in determining whether a unit retires (and in setting its FCM bid) as the sum of fixed O&M (including some overhead costs) and debt service, and assumed the same values for those costs for each unit in each of six broad categories and four categories of coal plants.

Q: Are LEI's estimates of fixed costs reasonable?

A: No, for several reasons. First, debt coverage should not be included in the costs used in setting the FCM bids or the decision of whether to stay on line, since those costs cannot be avoided by retirement or deactivation of the plant. Even if debt were avoidable, LEI has not explained how it estimated the debt component of fixed costs.

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[24]Newington is still owned by PSNH, a regulated utility (and, like CL&P, a subsidiary or Northeast Utilities).

[25]"The net revenue shortfall is simply the money that it needs in order to avoid retirement after accounting for its profits from energy and/or LFRM sales" (Report at 25.) See also Report at 61 and IR OCC-39 for further explanations of LEI's approach.

Second, a single fixed-O&M estimate for all gas-fired combined-cycle, combustion turbine, diesel and steam plants in New England is unrealistic. LEI has not explained how much of its fixed-cost estimates are for O&M, but O&M is both much lower and much more variable than LEI's estimates of fixed costs. The O&M for merchant plants is not publicly available, but the 2005 and 2006 FERC Form 1 filings for Public Service of New Hampshire, which still owns several plants, shows total O&M of $1–$7/kW-year for its oil-fired combustion turbines and $24–$37/kW-year for the Newington dual-fueled oil steam plant.

Third, LEI fails to consider the costs that are most likely to lead to retirement of plants, namely the important and lumpy capital additions that various units require at various times, due to aging and environmental requirements.[26] These capital additions may be for major repairs or replacements of worn-out equipment, addition of cooling towers at Brayton to comply with regulatory limits on its once-through cooling system, addition of safety improvements or fish bypass features at small hydro sites, or addition or upgrade of emissions-control equipment on fossil generation. Such additions occur sporadically, but can be large enough to make continued operation uneconomic. In fact, as noted above, LEI invokes the costs of compliance with environmental restrictions to justify the retirement of Newington in Scenarios 8 and 9, but does not appear to apply this factor across the board.

[26]For example, one of the PSNH peakers incurred additional capacity costs of $49/kW in 2006.

Q: Does Newington appear to be a logical choice for retirement?

A: No. Newington is one of the most modern and largest steam units in New England, and burns both heavy oil and gas.[27] Both larger size and later vintage tend to reduce the costs of operating these plants, and the dual-fuel capability also reduces costs and increases net energy revenues. We would expect older and smaller units, or units with histories of operating problems, to be retired first. Obvious candidates would be Wyman 1–3 in Maine, West Springfield 3, and perhaps some of the Connecticut units, despite the higher Connecticut energy prices.

Specifically, New Haven Harbor, Bridgeport 2, and Norwalk Harbor 1 & 2 appear to be credible retirement candidates, since they are currently supported by reliability must-run (RMR) contracts that expire in 2010.

Connecticut Reliability Contracts

Owner/Unit	**2007 CELT Summer Cap** (MW)	**Annualized Fixed Revenue Requirement**	**Dollars per kW per Month**
New Haven Harbor	448	$37,500,000	$6.98
Bridgeport Harbor 2	130	14,000,000	8.94
Norwalk Harbor 1&2	330	38,256,241	9.66

Source: "Reliability Agreements—Annual Fixed Costs Summary," ISO-NE, 4/19/07; Reliability Agreement Status Summary, ISO-NE, 4/30/07

The revenue requirements for these units in their RMR contracts exceed LEI's projection of the FCM price. These units will not be eligible for LFRM revenues, and are not likely to earn much net energy revenue. In other words, once their RMR contracts expire, these units are unlikely to produce sufficient

[27] Only three steam units in New England are much larger than Newington: Wyman 4, Canal 1 and Canal 2. The first two are limited to burning oil, and Wyman in particular is located in Maine, where energy-market prices are generally the lowest in New England.

market revenues to cover their costs. Yet LEI does not retire them in any scenario.

Q: How would a more-realistic treatment of retirements differ from LEI's?

A: Had LEI distributed fixed costs—both continuing costs and occasional large capital additions—more realistically across units, it would probably have found more units retiring in the baseline scenarios with low capacity and energy prices, thereby reducing excess supply and bringing prices back towards normal levels.

Realistic treatment of retirements in the cases with RFP projects would similarly raise prices in those cases, reducing LEI's overstated estimates of benefits in the energy and especially the capacity market. We take up this point in more detail in the next section.

C. Effect of RFP Projects on Other Resources

Q: When LEI runs its models with the addition of the RFP projects, how does it adjust the generic resource additions?

A: London Economics freezes the generic resource additions, and does not adjust the size, type, timing, or location of those additions, regardless of the scale of the RFP projects it adds.

Q: Is this approach consistent with LEI's baseline assumptions?

A: No. In the baseline, LEI assumes that generic resources are added only if they are : (1) needed to meet FCM or LFRM requirements; and (2) profitable to their owners.[28] However, once it adds an RFP project, LEI abandons those rules and adds generic resources that are neither needed nor profitable.

[28]As we noted above, LEI added peakers in Connecticut that would not meet LEI's assumed profit targets.

Q: Does LEI's practice of keeping the same set of generic resource additions—regardless of the RFP projects added—result in a meaningful comparison between the baseline and with-project cases?

A: No. In order to produce a realistic, "apples-to-apples" comparison between baseline and with-project cases, the analysis should identify the effect of the project on the system. When LEI adds a combined-cycle project, it does not merely assume that the rest of the system operates the same way as it would have without the project. Instead, LEI properly re-dispatches the entire system to determine the energy prices and emissions, recognizing the effect of the project on the economics of operating other units in the energy market. London Economics assumes that units whose bids do not clear in the energy market will not be operated.

In the same way, adding the project will change the economics of adding other new units and retaining existing units in the capacity market. If the modeling rule in the baseline is that generic units are added only if they are needed, that should also be the rule in the with-project case, for an "apples-to-apples" comparison. Just as plants that do not clear in the energy market should not be assumed to generate, plants that do not clear in the capacity market should not be assumed to be built.

Q: How does this failure to adjust the generic resource additions affect the supply situation?

A: The most obvious result is that reserve margins are much higher with the RFP projects than without.

In addition, with many of the RFP portfolios, significant amounts of the generic additions fail to clear in the FCM, and thus would not be profitable to build, including, in Scenario 2, 150–700 MW of the 2010 Connecticut peakers, up to 1,500 MW of combined-cycle capacity in other parts of New England in 2017–2021, and the 300 MW Connecticut combined-cycle plant LEI assumes for 2020. However, LEI assumes those units are added anyway.

Q: Is this result plausible?

A: No. The capacity that did not clear would not receive any FCM payment and hence would not even cover its costs in the first year, let alone over a sufficient period to pay back investors. As we explained in Section III.B.1, the 2010 Connecticut peaking units do not cover their costs over the first ten years, even in the baseline scenarios, and even if they clear in the FCM auction.[29] Many more of the generic additions would become uneconomic with the RFP projects added, since the generic units would not clear as new capacity (and hence would get zero FCM payment in their first year) and would also receive lower market energy and capacity payments.

Even for the new generic units that LEI expects to clear with that addition of the RFP projects, LEI's analysis mixes apples and oranges. As noted above, without the RFP projects, generic capacity is added only if it is needed; with the RFP projects, generic capacity is added anyway.

Consistent application of an expansion rule (either addition of all economic projects or addition of only economic additions needed to meet installed-reserve requirements) would have produced more reasonable results than LEI's mix-and-match modeling. If LEI had added all economic new capacity, the baseline case would have had more generic additions (probably thousands of MW more)

[29]The same appears to be true for the generic combined-cycle unit added in Connecticut in 2020.

and a comparable increase in retirements of uneconomic generation.[30] Adding a set of RFP projects and re-running the capacity addition and retirement computations with the all-economic rule would reduce generic additions and/or increase retirements. The same is true if LEI had applied its needed-capacity-only addition rule and allowed economic retirements in the runs with RFP projects, just as it does in the baseline scenarios.

Q: When LEI runs its models with the addition of the RFP projects, how does it adjust the retirements of existing units?

A: London Economics does not change the assumed retirements to reflect the addition of the RFP projects. Whatever retirement LEI includes in the baseline for a scenario is also included with the RFP projects, and no more. As with LEI's assumption that RFP projects do not affect generic additions, this assumption is implausible.

Q: Have you identified any existing generation that would fail to clear the FCM auction and would likely be retired?

A: Yes. Under LEI's assumptions, the 541-MW Ocean States Power plant would never clear in the FCM in 2011–2021 under Scenario 2 (the only scenario for which LEI has provided the FCM bids), and would certainly be retired. Pawtucket Power (63 MW) would not clear in 2011–2013, 2015, 2016, 2018, 2020 and 2021, and would clearly fail LEI's three-year test. Similarly, Montville

[30] If in Scenario 2, generic combined-cycle units were added in the rest of New England until they no longer cleared in the FCM, the Connecticut peakers would not clear and would not be added, keeping baseline LFRM prices at the $14/kW-month cap. Moreover, using LEI's retirement approach, thousands of megawatts of existing units would be retired in the baseline scenarios.

5 would not clear in 2015 and 2016, and would certainly fail to "recover its fixed costs over a three year period" (Report at 39) and would be retired.[31]

Q: What is the effect on screening of LEI's implausible assumptions about generic additions and retirement?

A: This error has a substantial effect on the capacity benefit that LEI attributes to the RFP projects. LEI simply *assumes* that the market will permanently have more capacity with the RFP projects than without. Hence, LEI artificially and arbitrarily suppresses FCM prices with the RFP project, creating illusory benefits for these projects.[32]

The effect of the RFP projects on energy prices is more difficult to determine. Baseload generation and energy efficiency in Connecticut would reduce Connecticut energy prices in the first several years, even if they displace equivalent generic peaker capacity in Connecticut or generic combined-cycle capacity elsewhere in New England. Nonetheless, since some generic units would be avoided by the RFP projects, the energy benefits would be less than LEI assumes. In addition, under the logic that LEI uses to determine baseline additions, RFP projects of more than 300 MW would eliminate the 300 MW Connecticut combined-cycle in 2020, further reducing the energy benefits after that date.

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[31] We do not believe these units are really the best candidates for retirement, but clearly some generation would be retired in response to addition of more combined-cycle capacity.

[32] If the conditions that LEI assumes in Scenarios 5, 8, and 9—a freeze on all other generation additions—were to come to pass, the RFP projects would have large market-price benefits. But those scenarios are implausible, as we discuss in Section III.A.

IV. Market Modeling

Q: Please describe LEI's model simulation of market prices.

A: Using a trio of market models of its own creation, LEI simulates annual market-clearing prices separately for the energy, forward-capacity, and forward-reserve markets. For each of the three product markets, LEI derives 15-year forecasts of market prices for:

- each of the nine baseline scenarios ("baseline market prices");
- each of the nine baseline scenarios with the addition of a single RFP project; and
- each of the nine baseline scenarios with the addition of a single portfolio of RFP projects.

Hence, LEI's analysis produces a set of eighteen price forecasts for each RFP project or portfolio: nine for the baseline scenarios with just generic additions, and nine more for the baseline scenarios with the addition of the RFP project or portfolio.

Each forecast of market prices involves running the three market models in a particular sequence, in order to simulate price interactions among the three product markets. London Economics first runs its POOLMOD simulation model to forecast energy-market prices. These energy prices are used to estimate annual operating profits (i.e., energy revenues less operating costs) for each generating plant. In addition, each POOLMOD run produces annual values for the Forward Reserve Strike Price. This strike price is used in LEI's modeling of the forward-reserve market to determine which resources are eligible to participate in the forward-reserve market. LEI then models the forward-reserve market, determines which resources are eligible to participate, determines which of the eligible resources clears the market in each year, and estimates annual LFRM revenues for each cleared resource.[33] London Economics then estimates price offers for each existing resource participating in the forward-capacity market as plant fixed costs (plus debt interest) less operating profits in the energy market and less LFRM revenues. Likewise, LEI estimates FCM price offers for new capacity as total capital and fixed cost less operating profits in the energy market and less LFRM revenues. The FCM model clears the forward-capacity market based on these estimates of price offers and LEI's estimates of capacity requirements. Finally, LEI determines the LFRM clearing price based on its simulation of the FCM clearing price.

Q: How are these various forecasts of market prices incorporated in LEI's economic evaluations of RFP projects and portfolios?

A: These forecasts of market prices are used to estimate both the "costs" and the "benefits" associated with each RFP project or portfolio. In LEI's analysis, "costs" are defined as contract payments for forward capacity less the market value of the contract forward capacity.[34] Contract market value, in turn, is derived as the product of contract capacity (either forward or reserve) and the market price for that capacity. Each RFP project or portfolio actually has nine estimates of market value, and thus cost, corresponding to the nine forecasts of market prices for that project or portfolio.

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[33]As discussed below, unlike for the energy and capacity markets, LEI does not estimate forward-reserve market prices on the basis of a simulation of market clearing of generator bids into the market. Instead, LEI estimates the LFRM price premium over the FCM clearing price based on a regression analysis of the historical relationship between supply margins in the forward-reserve market and the forward-reserve price premium.

[34]For those projects that offer forward reserves, project cost includes contract payments for reserve capacity and the offsetting market value of reserve capacity.

"Benefits" in LEI's analysis are defined as the reduction in costs to Connecticut load due to the decrease in market prices resulting from addition of the individual project or portfolio to a baseline scenario. In other words, benefits are determined by the difference between market prices for the baseline scenario and market prices resulting from the addition of the RFP project or portfolio to the baseline. As with the estimate of project cost, each RFP project or portfolio has nine estimates of market-price benefits, corresponding to the market-price forecasts (with and without the addition of the project or portfolio) for the nine baseline scenarios.

A. Energy Market Price Benefits

Q: Have you identified any problems with LEI's modeling of energy market benefits?

A: Yes. We have identified two potentially significant problems: (1) LEI's treatment of the random variation in the results of the POOLMOD model; and (2) LEI's failure to account for the Auction Revenue Rights that are credited to customers from the sale of Financial Transmission Rights.

1. Treatment of Random Variation

Q: Why are there random variations in the results of the POOLMOD model?

A: The POOLMOD model, like most production-costing models, computes the market price for each hour by matching the quantity of energy offered by available generators with the load in that hour, and then identifying the bid price for the most expensive unit dispatched in that hour.[35] In actual practice, the

[35]The computation is complicated by the need to schedule hydro plants that do not have enough water to generate at their maximum capacity in all hours and must be dispatched in the highest-price hours; pumped-storage generation, which must consume energy in some hours to produce

available generation is reduced by scheduled maintenance outages and by random forced outages, both of which must be approximated in the model. The scheduling of maintenance outages depends on the full set of units that must be maintained over the year and the number of days each unit must be offline.[36] Forced outages of generators are generally modeled as random occurrences, using a series of random numbers. For example, if the random numbers vary from zero to one, and a unit has a 5% forced outage rate, the model might treat the unit as being on forced outage every time its random number is above 0.95. Models generally have a formula that generates a list of apparently random numbers; the specific forced outages depend on the order in which the units are listed and matched against the random-number list, and on the starting point, or "seed", for the random-number generator. (Tr. at 376–378)

Any outage of a plant that would otherwise have operated in an hour will increase the market-clearing price in that hour, since the ISO (or the model) will need to dispatch additional units, which must have offered a higher bid price than the already-dispatched plants (or else those units would already have been operating). If forced outages occur in low-load hours, the market price of power will likely increase only modestly, as the market price is set by a slightly more expensive bid. But if a large amount of capacity happens to be out of service at a high-load hour, the market-clearing price is likely to rise much more.[37]

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energy in other hours; and thermal units (especially steam units) that may take hours to ramp up output to generate at full power.

[36]Determining the optimal maintenance schedule to minimize energy costs and the probability of having insufficient capacity (let alone approximating the ISO's maintenance schedules) is a difficult aspect of production-cost modeling.

[37]For a given load level, prices may also be much more sensitive to outages in the winter, when prices for the gas burned in the marginal units are high, than in the summer.

As a result, the energy market prices estimated for a year depend on the timing of maintenance outages and forced outages. The timing of maintenance outages in the model may change if additional generators are added, since the model will generally reshuffle maintenance schedules to accommodate the additional generation.[38] The forced outages vary with the list of units and the random-number seeds.

Q: How does random variation in the energy-price model affect LEI's analysis?

A: London Economics, like anyone using a production-cost model to estimate market prices, must accommodate the random variation in model results.[39] Because of the unpredictable effects of maintenance scheduling and the truly random assignment of forced outages, several runs of the same baseline case may produce several different market energy prices. Similarly, one set of model runs of three different cases (e.g., baseline capacity, the baseline plus Project X; and the baseline plus Project Y) may result in a different relative ranking of prices for these three cases than would another set of runs of the same three cases. For example, one set of runs might find the case with Project X to be least expensive, another might find the case with Project Y to be least expensive, while a third might find the baseline to be least expensive.

Assuming that Projects X and Y are both economic to operate, they would reduce energy prices in the real world, since the ISO would dispatch those units

[38]The same may be true if loads change.

[39]All of LEI's models depend on assumptions about future prices, loads, supplies, market structures, and other factors which, like any forecasting assumptions, may prove wrong. Only POOLMOD includes random-number generation.

only when they reduced costs. Yet POOLMOD might report that they would increase prices.

Q: How did LEI deal with this problem?

A: As we understand the situation, LEI took the following three measures to minimize the randomness of the POOLMOD results:[40]

- Freezing the maintenance schedule for each unit in the baseline, both pre-2010 existing units and later generic additions, and using that schedule for all the runs with RFP projects.
- Using the same random-number seed for the forced outages in all POOLMOD runs of either baseline scenarios or baseline scenarios with the addition of RFP projects or portfolios.
- Setting the energy benefits from most peaker resources to zero.

Q: Are these appropriate responses?

A: The first two measures are reasonable. The third is an incorrect and inappropriate response to the limitations of POOLMOD.

Q: Please describe the process by which LEI set the energy benefits from peakers to zero.

A: London Economics correctly observed the wide variation in its energy modeling results and realized that the random variation was making it difficult to determine the energy-market benefits of projects and portfolios. Rather than focusing on the problem by narrowing the uncertainty of the energy benefits, LEI decided that the solution to the shortcomings of POOLMOD was to set the energy benefits of certain resources to zero.

[40] Technical Meeting Handout at 29-31 and Tr. at 376-379.

In the Report (at 66), LEI says that its "testing involved running certain projects and portfolios over and over again with 30 different random number seeds and then cataloguing the distribution of projected price impacts.". Specifically, LEI ran 30 POOLMOD runs for each of seven hypothetical resources:[41]

- A generic 630-MW combined-cycle unit
- A generic 75-MW demand-response project in southwest Connecticut (SWCT).
- A generic 150-MW demand-response project outside SWCT.
- A generic 240-MW peaker outside SWCT.
- A generic 80-MW peaker in SWCT.
- A 5-MW energy-efficiency project.
- A combination of peaker and hydro capacity, to reflect the Shepaug proposal.

London Economics further explains that:

> We then constructed a confidence interval from this distribution, which then allowed us to distinguish whether the projected annual energy price impact (which were sometimes as low as $0.10/MWh) was statistically significant or not. Where the effects were found to not be statistically different from the baseline, we discarded the random impacts and conservatively used the baseline energy prices instead of the energy price impacts produced by these projects." (Report at 67).[42]

Based on this analysis, LEI decided that the energy benefits from all of these resource projects, except the combined-cycle unit and the 240-MW peaker,

[41]See IR OCC-95 and Tr. 6/14 at 379–382 (where LEI also claims to have run this analysis for a 50-MW energy-efficiency project).

[42]Report at 67. From IR OCC-98, it appears that the price effects for the hypothetical resources were often lower than $0.10/MWh.

had no energy benefits in any scenarios, and that the 240-MW peaker had energy market-price benefits in only Scenarios 8 (in three years) and 9 (in one year) (Report at 40). LEI thus set the energy benefits to zero for the following projects:[43]

- all of the energy-efficiency, demand-response and peaker projects of less than 188 MW;
- the larger peakers in almost all years and scenarios;
- portfolios with a combined-cycle project in all years before the combined-cycle unit comes on line; and
- all but one portfolio with combinations of energy-efficiency, demand-response, and peakers.[44]

Once LEI had identified its preferred Portfolio 89, it repeated the process for that portfolio, and again set energy savings equal to zero prior to the in-service date for Project E.[45]

Q: Would a $0.10/MWh reduction in annual energy price be an insignificant benefit for Connecticut consumers, as LEI implies?

A: No. LEI reports Connecticut electric energy use of 34 million to 45 million MWh in various years and scenarios, so a $0.10/MWh reduction in annual

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[43] Indeed, in IR OCC-108c, LEI states that it discarded the energy-price data from the runs. We do not understand why LEI would find it necessary or appropriate to discard this relatively small amount of data.

[44] Somehow, LEI determined that Project 114, a portfolio of 628 MW of peakers, has "statistically significant" energy savings in all years after 2011, when added to baseline scenarios 1, 2, 3, 5, and 8. LEI has not explained how it got those results, or why a 240-MW peaking unit has energy benefits in one year for Scenario 9, but a 628-MW portfolio of peaking units has none.

[45] London Economics ran POOLMOD 30 times for Portfolio 89, but reports only the results from one run.

energy price would be worth $3.4 million to $4.5 million annually, and tens of millions in present value benefits over the 15-year planning horizon. Adding those benefits would dramatically improve the cost-effectiveness of peaking, and possibly demand-response, projects.

The $5 million difference in energy-price benefits that LEI reports between Scenarios 87 and 89, for comparison, is driven by an average $0.05/MWh difference in energy prices over the life of the contracts. The $417 million energy-price benefit of Scenario 89 is the result of an average decrease in energy prices of about $0.85/MWh. Clearly, a $0.10/MWh reduction in energy prices is material.

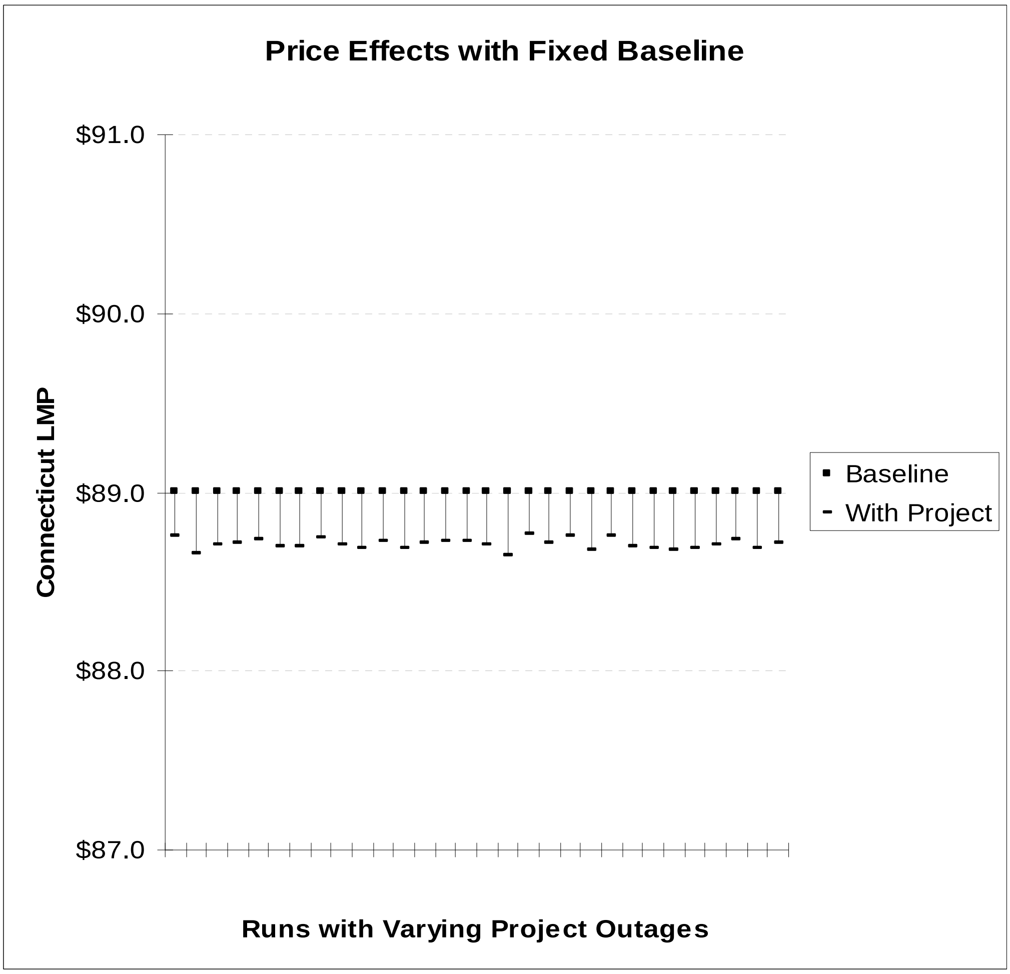
Q: Was LEI's test of statistical significance an appropriate way to assess the energy-market benefits of projects?

A: No, since LEI: (1) set up its comparisons inappropriately; (2) computed the confidence interval incorrectly; and (3) tested the wrong hypothesis.

Q: Are there any problems with LEI's comparisons of energy prices with and without the hypothetical projects?

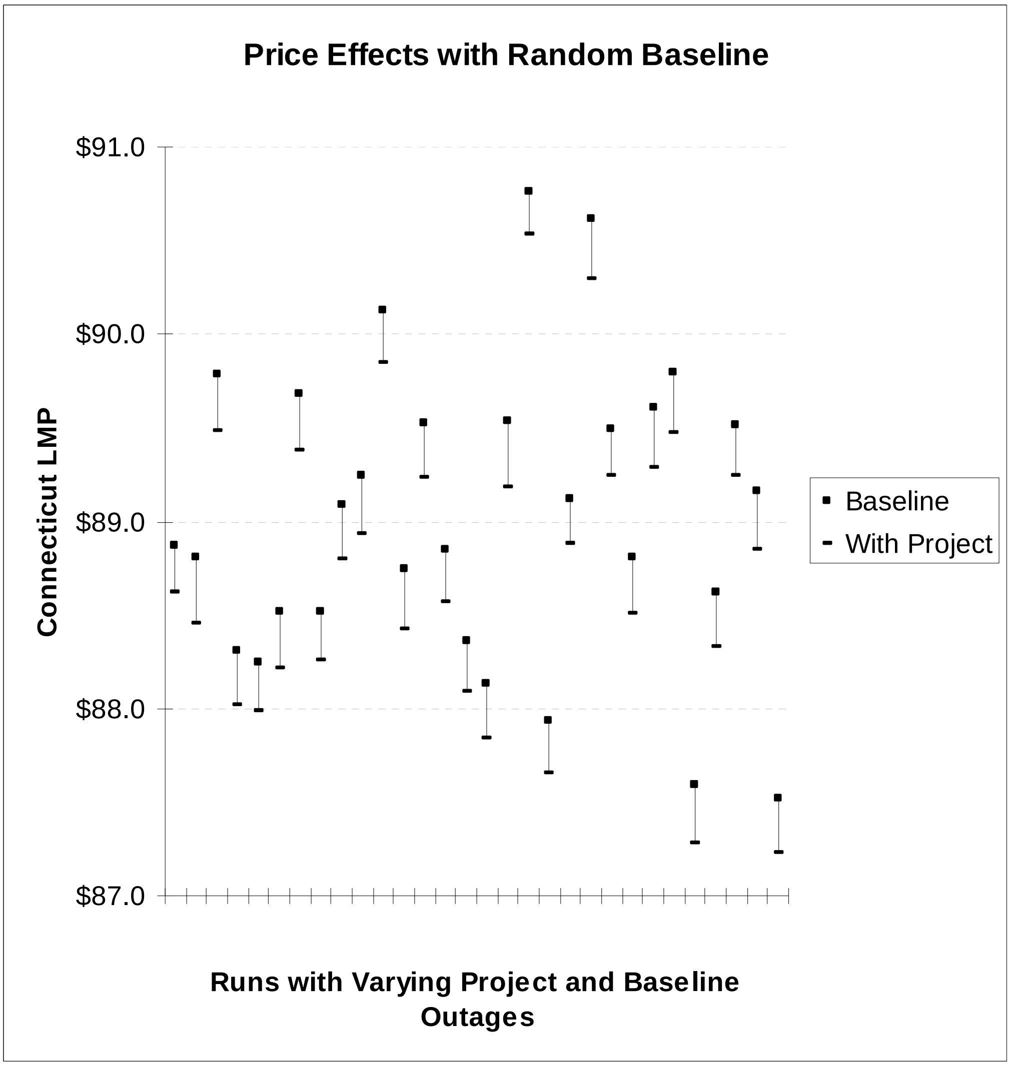
A: Yes. London Economics was trying to determine the variability in the incremental price effect of each project on the baseline system. Hence, LEI should have created a baseline scenario, with fixed maintenance and forced outage, and then estimated the effect on energy prices of adding the project with 30 (or whatever number of trials were needed) different outage patterns for the project.

The following two figures illustrate the differences between the logical approach, looking at the random variation in the effect of the project's outage, and LEI's approach, which conflates the effects of random variation in the hypothetical project's outages with the effects of the randomness of the outages of some 300 existing resources in the baseline.[46] The first figure shows what the 2011 prices might look like for a fixed baseline (equal to the $89/MWh average of LEI's 30 baseline runs) and for a set of runs that includes a hypothetical project. In this illustrative example, the hypothetical project reduces the market energy price by $0.2/MWh to $0.4/MWh, for an average over the 30 runs of $0.3/MWh and a standard deviation of $0.03/MWh. These price reductions are real, if inherently uncertain.



[46]See the response to IR-OCC-95. This is an illustrative example; LEI did not give us the actual data from its 30 runs, as we requested in IR OCC-98.

In contrast, LEI varied the outages for each of the baseline resources, as well as the project outages, resulting in prices more like the following figure, which varies the baseline price with a normal distribution and standard deviation of $0.8/MWh, lower than LEI's estimated standard deviation of $0.9/MWh. We set the price effect of the project in each run equal to the corresponding run in the previous figure.



With the randomness of the baseline system thrown into the analysis, the prices, with or without the project, are much more variable than in the first analysis. LEI saw the wide combined variability and concluded erroneously that the projects had no energy benefits.

Q: Were there any problems with LEI's computation of the confidence interval?

A: Yes. LEI estimated the variance of the difference in prices between the baseline and the case with an added hypothetical project as the sum of the variances of the prices in the two cases. This computation would be correct *if* the distributions of the two variables (baseline price and with-project price) were independent. But clearly, the baseline price and the with-project price for runs with the same random-number seed will be highly correlated: if a couple of large units are out of service at the time in the baseline run, they will also be out of service at the same time in the with-project run. Since the variation in price between the baseline cases with different random-number seeds must be much larger than the variation in price due to the performance of the hypothetical project, the baseline price and the with-project price are probably nearly perfectly correlated.

Q: How would taking correlation between the baseline price and the with-project price affect the confidence interval?

A: The variance of the difference between two correlated random variables *x* and *y* is

$$\text{Variance(x)} + \text{Variance (y)} + 2 \times \rho \times \sqrt{\text{Variance(x)} \times \text{Variance(y)}}$$

where ρ is the correlation between *x* and *y*.

Using the correct formulation in the calculation of the variance and confidence interval in IR OCC-98, and assuming perfect correlation between the variables, the price effect of the large peaker for Scenario 2 and 3 is significantly different from zero in ten of the twelve years that LEI models. However, with LEI's incorrect computation, this price effect never passes the significance test.

Q: What do you mean that LEI tested the wrong hypothesis about the significance of projects' effects on the energy market price?

A: LEI chose to test whether the difference in the energy-market prices between the baseline POOLMOD run and the run with a particular project was statistically significant. That test is appropriate if one suspects that the projects have no real energy benefits, and the differences between the baseline and the project runs are accidental. However, in this case, it is likely that at least the peaking units and energy-efficiency resources would reduce energy prices, and the real question is how large that reduction would be.[47]

In essence, LEI tested whether a value of zero fell within 1.96 standard deviations of the average estimate of energy benefits from the 30 POOLMOD runs.[48] In other words, LEI tested whether the actual mean can be differentiated from zero at a specific confidence level. If a value of zero fell within 1.96 standard deviations of the observed mean, LEI determined that the actual mean could not be differentiated from zero, and then set energy benefits to zero.

This is a meaningless test, since we know that the actual benefits are not zero, and the large standard deviation in the POOLMOD results is a measure of POOLMOD's wide margin of error. Moreover, LEI misinterpreted and misapplied

[47]The DR projects may have little or no energy benefit, depending on how rarely they are dispatched.

[48]LEI provided conflicting information regarding this computation. In the Technical Meeting handouts (at 31), LEI states that it required the sample mean to be 1.64 standard deviations from zero, which would be consistent with seeking a 95% confidence that the true mean is greater than zero. In IR OCC-98, LEI actually required the sample mean to be 1.96 standard deviations from zero, which would be consistent with seeking a 97.5% confidence.

the test results. If a zero value fell within the assumed confidence interval (i.e. mean value – 1.96 standard deviations), it is also the case that a value greater than the observed mean would fall within the assumed confidence interval (i.e., mean value + 1.96 standard deviations.) Thus, by LEI's logic, it would have been just as reasonable to set energy benefits to a value that exceeds the mean of the 30 runs as it would have been to set the value to zero.

Q: Did any of LEI's modeling assumptions exacerbate the noise in model results?

A: Yes. In its 30 runs of the hypothetical peaking units, LEI modeled the hypothetical peaking plant as a single combustion turbine. This is inconsistent with the actual bids: all but one of the peaking projects offered in response to the RFP consisted of multiple units. If LEI had assumed, consistent with actual bids, that the hypothetical peaking plant consisted of multiple smaller combustion turbines, and then modeled each of these combustion turbines as separate resources, then the effect of hypothetical-plant outages would have tended to be more uniform across runs. As a result, LEI's analysis of statistical significance would likely have shown less variation in energy savings, thereby improving the odds of passing LEI's statistical-significance test.

Q: Did LEI's approach for addressing random variation fully resolve the problem of noise in model results?

A: Apparently not. Even with these measures, LEI's simulation of energy prices for many portfolios resulted in *lower* energy benefits (i.e., higher energy prices) when additional resources were added to the portfolio.

We identified 22 pairs of portfolios differing only by one peaker (K, M, O, Q, R) or demand-response project (B, C, or I), and four more pairs differing by two such projects (Q and M or I and C). One pair (Portfolios 85 and 113) have identical prices. Of the remaining 25 pairs, every one showed negative benefits for the incremental projects in at least one of the years 2009–2021, with an average of over 7 years with negative benefits. Of some 382 annual runs (excluding 2009 for those portfolios for which LEI set benefits to zero), 181 runs, or 47%, showed the incremental peaking or demand-response capacity raising market energy costs. Thus, almost half the time, the POOLMOD results showed energy prices moving in the wrong direction as peaking or demand-response resources were added.

Since demand-response or peaking plant should either have no effect or perhaps decrease prices, the negative differences and perhaps some of the positive ones must be due to noise in LEI's modeling.

Q: Why does this noise persist?

A: Apparently, this persistence is due to the inability to freeze maintenance or forced outage schedules for new resources in POOLMOD. For example, POOLMOD would likely schedule outages for a new combined-cycle plant differently in a run with just the new combined-cycle plant added to a baseline scenario than it would in a run that adds both the combined-cycle plant and a new demand-response resource. As a result, the difference in energy prices between these two runs may simply be an artifact of the fact that the combined-cycle's outage schedule was not frozen in the two runs.

This noise affects energy benefits because of an inconsistent application of LEI's test of statistical significance. When evaluated in isolation, the impact on energy prices, whether positive or negative, from the addition of a demand-response project to a baseline scenario would be deemed to be statistically insignificant and thus set to zero. In contrast, when considered to be part of a larger portfolio, the *incremental* impact of the demand-response project on energy prices would be deemed to be statistically significant, so long as any other resource in the portfolio had statistically significant impacts when evaluated in isolation. (Tr. at 387) Thus, when included as part of a larger portfolio, the noise associated with the modeling of the demand-response project persists in the form of illusory increases to energy prices.

Q: Does this noise affect LEI's comparison among portfolios?

A: Yes. This noise, along with the inconsistent application of the statistical-significance test, produces the counter-intuitive result that energy benefits for Portfolio 87 (which is Portfolio 89 plus two demand-response projects) are $5 million lower than those for Portfolio 89. Assuming more-realistically that energy benefits are the same in these two portfolios, Portfolio 87 would prove to be superior to Portfolio 89 under LEI's analysis.

In short, LEI's choice of Portfolio 89 was largely the result of the random-number generator in POOLMOD, which apparently picked better times for outages of the combined-cycle in the Portfolio 89 run than it did for the Portfolio 87 run, and perhaps for many other runs.

Q: How should LEI have dealt with the limits in its model?

A: London Economics should have run POOLMOD with enough small units (and not just model many small resources as one large unit, as LEI did with its hypothetical 240 MW peaker) to get useful estimates of the energy benefits, and scaled those benefits for projects too small to model directly in POOLMOD. LEI should also have checked its energy-price results to ensure that adding resources did not erroneously increase energy prices.

2. Failure to Account for Auction Revenue Rights

Q: What are Auction Revenue Rights?

A: Auction Revenue Rights (ARR) are a financial product created by ISO New England that gives the bearer the right to revenues from the auction of Financial Transmission Rights (FTR); such ARRs are for the most part allocated to load. Financial Transmission Rights, in turn, are a financial product that gives the bearer the right to congestion revenues on a specified transmission path. For example, the owner of a 50MW FTR from the Massachusetts Hub into the Connecticut zone would receive congestion revenues (or make congestion payments) in each hour equal to 50 MW times the difference between energy prices at the Massachusetts Hub and in the Connecticut zone. Financial Transmission Rights are sold at auctions conducted by ISO New England at prices that, in theory, reflect buyers' expectations regarding future congestion costs. Consequently, the auction revenues credited to load through ARRs provide an indirect hedge against congestion costs.

Q: How does this ARR hedge affect the energy-price benefits to load from an RFP project?

A: Auction Revenue Rights moderate the benefits to load associated with the reduction in energy prices from an RFP project. Since FTR prices, and hence ARR values, rise as expected congestion costs rise, and fall when expected congestion costs fall, projects that reduce Connecticut Locational Marginal Prices will also tend to reduce the value of Connecticut ARRs. So, for example, if a portfolio reduced Connecticut market prices by $0.1/MWh, it would reduce the market value of energy in Connecticut by about $3.5 million annually. The portfolio would also reduce congestion into Connecticut, perhaps by

$0.07/MWh, or about $2.5 million for all Connecticut load. Since ARRs have covered about 30%–40% of congestion, the value of the ARRs to Connecticut load would decline about $0.8 million annually. Hence, in this example, total benefits for Connecticut customers from the energy-market effects of the portfolio would be about $3.5 million minus $0.8 million, or $2.7 million.

Q: Did LEI account for the impact of ARRs on energy benefits?

A: No. As a result, LEI's estimates of energy benefits to Connecticut load are likely overstated.

B. Forward Capacity Market Benefits

Q: How does LEI model Forward Capacity Market prices?

A: London Economics developed a spreadsheet model that simulates annual market clearing in accordance with the market rules and procedures for the forward-capacity market. London Economics estimates price offers for each existing resource participating in the forward-capacity market as plant fixed costs (plus debt interest) less operating profits in the energy market and less LFRM revenues. Likewise, LEI estimates FCM price offers for new capacity as total capital and fixed cost less operating profits in the energy market and less LFRM revenues.[49] The FCM model stacks these price offers in ascending order to create an FCM "supply curve," and then clears this supply curve against LEI's estimate of capacity requirements to determine the market price.

[49]New resources are assumed to bid like an existing resource, i.e., at fixed cost plus debt interest less energy and LFRM revenues, in all auctions following the first auction where the resource clears.

Q: Is LEI's approach to building an FCM supply curve reasonable?

A: Conceptually, yes. As long as the market is expected to be workably competitive, it is reasonable to assume as LEI did that bidders will price their capacity offers at avoidable capital and fixed costs less profits from other product markets.

However, as described in Section III.B.2 above, LEI misestimated likely price offers by

- relying on artificially uniform estimates of avoidable fixed costs for existing units;
- failing to reflect the wide range of capital additions required by various units in various years;
- inappropriately including debt interest as an avoidable fixed cost for existing resources; and
- relying on inconsistent finance assumptions for new generic combined-cycle and combustion-turbine resources.

In addition, LEI apparently did not consider how uncertainty in the quantities or prices offered by bidders (which, in turn, depend on uncertain expectations regarding avoidable cost, LFRM revenues, energy profits, etc.) or in the amount of eligible new resources might have affected the composition of the supply curve and market-clearing prices.[50]

Q: How might consideration of uncertainty have affected LEI's simulation of FCM prices?

A: One example involves LEI's simulation of market clearing for the baseline scenarios in 2020. In that year, the FCM model forecasts that clearing prices for

[50] Likewise, LEI did not account for uncertainty in setting the capacity requirement for clearing an FCM auction three years in advance of the delivery year.

existing and generic new capacity will jump to their respective price caps. Almost all of the RFP projects avoid this price jump and are accordingly credited with capacity-price benefits in that year that are large enough to materially affect project economics. However, these benefits are extremely sensitive to assumptions regarding capacity requirements and the amount of capacity eligible to participate in the FCM auction and thus are highly uncertain.

Prices spike to capped levels in 2020 because of a complicated interaction between two special pricing rules that LEI's model triggers in that year. One of these pricing rules forces the market to clear the Connecticut zone separately from the rest of New England. This rule is implemented in any year when the amount of capacity offered into the previous year's auction is less than the current year's capacity requirement. The other pricing rule forces prices to clear at capped levels in any zone and any year where the amount of zonal capacity offered into the auction is less than the zonal capacity requirement.

In essence, these pricing rules were triggered in 2020 by LEI's deterministic forecast of capacity requirements for the Connecticut zone and for the rest of the New England region.[51] Needless to say, such forecasts are subject to considerable uncertainty. Given this substantial uncertainty, LEI should have determined how sensitive the FCM model results for 2020 were to their pinpoint estimates of capacity requirements and supply quantities, and appropriately

[51]These rules were also triggered due to LEI's deterministic forecast of generic new additions. The first pricing rule triggered in 2020 because LEI assumed unrealistically that no new capacity other than its forecasted generic additions would be offered into the 2019 auction. A more likely scenario is that there would be additional peaking or demand-response projects that are in early stages of development in 2016 (when the 2019 auction would be conducted) that are available to bid into the 2019 auction. Even if these additional resources failed to clear in the 2019 auction, they would have still been counted as available 2019 capacity under the first pricing rule.

discounted such results to reflect the likelihood that the two pricing rules would actually be triggered.

Apparently, LEI did not evaluate this likelihood. If LEI had done so, it would have realized that the price result in 2020 was sensitive to small changes in the forecast of capacity requirements and offers. This is clear from LEI's economic evaluation of the RFP projects, where the addition of any RFP project to the baseline scenario, except for the very smallest 5MW Project D, avoids the triggering of the two pricing rules and the spike in the FCM clearing price.

Q: You previously noted that LEI was unreasonable in assuming that the schedule for adding generic units would not be changed by the addition of RFP projects. What would be the effect on FCM prices of correcting this error?

A: If an RFP project displaced an equal amount of generic new capacity, or led to the retirement of an equal amount of existing capacity, the price reductions that LEI forecasts in the forward capacity market would essentially vanish. In fact, to the extent that this RFP project also reduces energy prices, it would tend to increase the FCM price and lead to negative capacity benefits.[52]

C. Forward Reserve Market Benefits

Q: How did LEI estimate the forward-reserve benefits of adding RFP projects to baseline scenarios?

A: As described in IR OCC-89, LEI estimated the LFRM premium, the difference between the LFRM price and the FCM price, in $/kW-month as

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[52]Capacity prices may also be slightly lower (or higher) if more (or less) than the project capacity is not built or retired; these differences would just be unpredictable noise, and should not be included as costs or benefits of particular projects.

$$2.93 - 0.8 \times \text{LFRM margin},$$

where the LFRM margin is the percentage by which forward reserves offered exceeds the forward-reserve requirement. Using ISO-NE estimates, LEI assumed that the forward-reserve requirement would be 1,340 MW for Connecticut as a whole. So long as the forward reserve offered in Connecticut is less than 1,340 MW, the LFRM premium would be set by the ISO cap of $14/kW-month minus the FCM price. Once the amount of forward reserves offered exceeds 1,340, LEI expects that the LFRM premium would fall to $2.90/kW-month, and decline by another 8¢ for every 10% increase in reserves offered.

While LEI has not described in any detail its derivation of the amount of forward reserves offered, it appears that LEI made some judgment regarding which resources choose to bid in the LFRM. Specifically, as energy-market prices rise, LEI apparently assumes that more resources will decline to participate in the LFRM, which requires lower-cost resources to raise their energy bids and participate less often in the energy market.[53]

Q: What problems have you identified with LEI's modeling of the LFRM?

A: We have identified four problems with LEI's modeling of the LFRM:

- As discussed in Section III.B.1, LEI's decision to assume that the market would solve Connecticut's LFRM problem (both for cost and for reliability) is inconsistent with the Act's purpose for conducting this RFP.
- Also as discussed in Section III.B.1, the 700 MW of generic peaking additions assumed by LEI to resolve the Connecticut LFRM shortage

[53] See Needs Assessment at 50.

would likely not have been built, since they do not earn enough revenues to cover required return in LEI's simulations.

- The formula by which LEI related the LFRM margin to the LFRM premium appears to be derived from regressions on historical data unrelated to the LFRM margin. Moreover, LEI inconsistently forecasts the LFRM premium using a different measure of the LFRM margin in its formula than was used in the regression analysis to derive the formula.
- The projected LFRM prices do not reflect the market power of some generators.

Q: Is it reasonable to assume, as LEI did, that the LFRM premium would vary with the LFRM margin?

A: Yes. London Economic's conceptual approach of estimating the premium as a function of the margin was a reasonable simplification of the complex pricing dynamics of the forward-reserve market.

Q: Did LEI estimate in a reasonable manner the relationship between the LFRM margin and the LFRM premium?

A: No. There are problems in the data that LEI used in deriving the formula, the regression analysis that LEI performed, and the formula results.

Q: What were the problems with the data and regression that LEI used to derive the relationship between the LFRM margin and the LFRM premium?

A: London Economics did not analyze the FRM premium as a function of the FRM margin. There were only six ISO-wide FRM auctions for LEI to analyze (from winter 2003–04 through summer 2006), and the margins and premiums did not follow a clear pattern. Instead, LEI regressed the FRM premium from each of the FRM auctions against the share of total cleared FRM capacity represented by each of the cleared resources. (IR OCC-89) This step would appear to create a more observations for the independent variable in the regression, and thus create more robust results, but actually just generates 70 data points for each auction, all with the same price for the dependent variable. We do not understand what LEI thinks it gained by this reformulation of the problem. Moreover, it is not clear why LEI thinks that this asset-based independent variable – the ratio of each cleared asset's capacity to total cleared FRM capacity – is a reasonable proxy for total FRM margin.

Q: Did LEI use this asset-based ratio to forecast the premium in future LFRM auctions?

A: No. To forecast the annual premium, LEI substituted the aggregate LFRM margin as the independent variable in the regression equation. (Tr. at 281) Thus, LEI inconsistently developed the regression formula using one measure of the independent variable, and then forecast the LFRM premium using a different measure of the independent variable in the regression formula.

Q: Does the resulting formula yield reasonably plausible results?

A: No. The regression equation LEI provides in IR OCC-89 and uses in its analyses estimates that the LFRM premium for Connecticut would be $2.93/kW-month with essentially zero margin, such as with 1,341 MW bidding into the auction (which would be a margin of about 0.1%). The price would fall by $0.008/kW-month for each 1% increase in the LFRM margin, to $2.13 for a 100% margin (i.e., twice the needed reserves bidding into the auction).

There are two problems with this formula. First, it assumes a precipitous drop in LFRM prices once the offered LFRM is even slightly above the required 1,340 MW. At a zero margin, the premium is set at the ISO cap of $14/kW-month minus the FCM price. Assuming an FCM price of $6/kW-month, the

LFRM premium at zero margin would be about $8/kW-month. With the offer of any additional forward reserves, the premium in Connecticut would fall by over 60% to $2.93. That outcome is simply implausible, especially given the very gradual price change LEI expects as margin increases beyond 1 MW.

The regression results also do not look much like the historical results. Of the six FRM auctions, three resulted in premiums of $3.53 to $4.23/kW-month, with supply margins of 85% to 108%; LEI's formula would predict premiums of $2 to $2.25 for this range of margins. A fourth auction resulted in a premium of $1.30 with a supply margin of 48%, for which LEI would predict a $2.55 premium.

In addition, LEI does not increase the LFRM price over time to reflect inflation from the 2003–2006 historical period to the 2009–2021 forecast period.

Q: Did LEI attempt to assess the desirability of additional peakers to serve the LFRM market, if the market does not supply the 700 MW of generic peakers?

A: LEI claims to have done that analysis:

> Our Economic Analysis revealed that it was not cost-effective to procure the full 600 MW amount of peaking capacity needed to meet Connecticut's locational forward reserve requirements. Although substantial peaking capacity was bid into this RFP, the potential benefits of that peaking capacity did not outweigh its expected costs.[54]

However, this claim appears to be untrue. All of the analyses LEI has provided assume the addition of the 700 MW of generic peakers (in 2010 for Scenarios 1–4). When the generic peakers are delayed, in Scenarios 5, 8, and 9, the amount of LFRM capacity that LEI adds is not enough to satisfy the Connecticut requirement and reduce the LFRM price from its cap. In the most

[54]Report at 9. The reference to 600 MW in this quote should read 650 or 700 MW.

aggressive portfolio, LEI adds 628 MW of peakers, just enough to meet the LFRM requirements in the Needs Assessment. In the Bid Evaluation Model, LEI now assumes that, without the generic peakers, Connecticut's LFRM deficiency would be at least 650 MW in 2010, and higher in later years, apparently because LEI expects less on-line capacity to opt into the LRFM.[55]

Thus, LEI never tested whether it was cost-effective to procure the full 700 MW of peaking capacity needed to meet Connecticut's LFRM requirements if the market provided none. In most scenarios, LEI compares the 700 MW of market generic peakers to 770 MW of market and RFP peakers, or 800 MW, or 1,328 MW. In the delayed-capacity cases, LEI compares 0 MW to 70 MW, 100 MW, or even 628 MW, but never enough to affect the LFRM price.

Q: Did the Department offer any other explanation for LEI's failure to consider the addition of enough LFRM to meet the Connecticut requirement?

A: In its Final Decision in Docket No. 05-07-14Ph02 (Attachment 5 at 12), the Department states that

> the timing of when plants come online – and how much capacity comes online - is extremely important in the LFRM due to the fixed procurement target set by ISO-NE. A significant amount of LFRM capacity is needed in the short term to create a positive net benefit. The Department did not receive bids for a sufficient amount of peaking capacity that would be online in the near term to decrease LFRM prices from what they would otherwise be.

This explanation suggests that the Department is under the impression that the LFRM problem would be solved by the market within a few years, so only

[55]The Decision in Docket No.05-07-14Ph02 (Attachment 5, p. 13) indicates that the LFRM need was 610 MW. This finding is not consistent with the values in the Needs Assessment or LEI's Bid Evaluation Model.

the "peaking capacity that would be online in the near term" would be helpful in reducing LFRM price or improving reliability. The Department may also be under the impression that LEI had some evidence that the 700 MW of generic Connecticut peaking units in its baseline would actually be built in 2010. In fact, as we note elsewhere, the 700 MW of peaking additions are just an assumption, which is inconsistent with LEI's own modeling:

- In Scenarios 5, 8 and 9, the in-service date for the generic peaking units is delayed to 2013 or 2014. As a result, all of the resources bid in the RFP would be on-line before the market solved the forward-reserve shortage. LEI gives these scenarios a combined 35% probability.
- The Connecticut peaking units would be underbid by out-of-state combined-cycle units in the FCM, not clear in the capacity market, and not be built.
- Even if the peaking units could have cleared in the FCM at the bid prices LEI assumes for them, the developers would not go ahead with the plants if they agreed with LEI's projection of falling FCM price, since they would not recover their targeted return.

Both LEI and the Department have presented conflicting comments regarding what analyses LEI actually performed to determine the need for Connecticut LFRM supply. So far as we have been able to determine, LEI did not analyze this issue, but rather assumed it away.

Q: Did LEI properly reflect the likely response of existing plants that provide LFRM to the addition of peaking units?

A: No. It appears that it would be beneficial for NRG and PPL to withhold some of their peaking capacity from the LFRM, at least given LEI's assumptions about LFRM prices. NRG owns about 270 MW of peakers in Connecticut, which, again assuming an FCM price of $6/kW-month, would make about $8/kW-month in the LFRM market if the market were short, or something like $2.90/kW-month if there were any surplus. NRG would be better off pricing its LFRM in the $8 range and clearing as little as 100 MW, than allowing the Connecticut LFRM price to fall to the price LEI assumes. For PPL, with its 214 MW of peakers, clearing 80 MW at $8/kW-month is preferable to clearing all of its capacity at $2.90/kW-month. Hence, a 300-MW surplus of LFRM would be required in Connecticut to offset this withholding and bring down the LFRM price to $2.90, even if none of the generic peaker additions participated in the withholding.

These examples demonstrate that the steep drop in LFRM prices that LEI anticipates is unlikely, and that the Department should reconsider how best to reduce LFRM costs in Connecticut.

D. Modeling Project Costs

Q: You explained in Section II.A that LEI compares the market-price benefits discussed in the preceding sections to what it calls "costs," the contract payments minus the market value of the contract capacity. Does LEI properly compute contract costs?

A: Yes, except in certain circumstances, when LEI fails to subtract the market value of the contract capacity from the contract payments in some years. Specifically,

- London Economics does not subtract the FCM market price from the FCM contract cost if Connecticut capacity is insufficient. In other words, LEI assumes that FCM settlement revenues are not credited against contract payments if Connecticut does not have enough capacity to meet its local sourcing requirement. This situation happens only in Scenarios 8 and 9 and then only for a couple years.

- Similarly, LAI does not subtract the LFRM price from the LFRM contract cost if Connecticut forward reserves are insufficient. In other words, LEI assumes that LFRM settlement revenues are not credited against contract payments if Connecticut is short of forward reserves. This condition applies in all scenarios through 2009, in 2012 in Scenario 5, in 2013 in Scenario 8, and in 2014 in Scenario 9.

The years for which LEI fails to credit market prices against the cost of the contract are the years with the highest prices.

In IR OCC-110 and IR OCC-111, London Economics acknowledges this error in its calculations.[56]

Q: Is there any logical reason for LEI to exclude the settlement value in estimating the contract costs in these years?

A: No. Any RFP project that offers to provide forward-capacity or forward-reserves must credit back to contract costs all revenues received from bidding into these product markets in every year, whether the market is short or long. For example, suppose the Connecticut LFR market is 400 MW short, resulting in the LFRM premium being set at its cap of $14/kW-month minus the FCM price, or about $8/kW-month in with an assumed FCM price of $4/kW-month. In this case, the ISO will pay a 100 MW RFP peaking project $1 million ($10/kW times 100,000 kW) per month for the LFR capacity it offers into and clears the market. If the RFP project is under contract to provide forward reserves, the utilities' monthly bills from the project will be credited with the same $1 million.[57]

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[56]These responses were marked as "confidential", although they apparently contain no materials covered by the protective order. Due to the confidential designation of these responses, we cannot reveal any more information about LEI's explanation at this point in time.

[57]As discussed in Section III.B.1, if the forward-reserve market is still short after the addition of an RFP project, then the addition of the RFP project will increase LFRM costs to Connecticut

E. Corrected Analyses

Q: Have you corrected the Bid Evaluation Model?

A: Yes. We have corrected LEI's model logic for Portfolio 89 and each of its component generation projects in the following ways:

1. We eliminated all capacity-price benefits from the model, since addition of the RFP resources would displace roughly equal amounts of other resources in the forward-capacity auction.
2. We eliminated half the energy savings from Portfolio 89 and Project E from 2020 onward, when they would displace the 300 MW combined-cycle unit that LEI scheduled for Connecticut in the baseline.[58]
3. We credited projects O and R with an estimate of their energy-price benefits, interpolated from LEI's results for the 240 MW peaker (IR OCC-98).[59] The price reductions were generally proportionately greater for the 80 MW peaker and for Project 114 (for the scenarios in which LEI reported the energy savings) than for the 240 MW peaker, so we may have understated the interpolation of peaker energy benefits.
4. We corrected LEI's error regarding the treatment of the market revenue from the contracts. We credit the market revenue against the contract price in all years, as provided in the contracts, while LEI ignores the market

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consumers. London Economics reflects this increased cost in its Bid Evaluation Model as a negative market-price benefit.

[58]London Economics also overstated the energy benefits of these portfolios, by ignoring both the impact of ARRs and the fact that combined-cycle units added through the RFP would reduce the addition of generic baseload outside Connecticut.

[59] We computed the $/MWh price reduction per 100 MW (the change in energy price due to the 240 MW project, divided by 2.4) for each year and scenario and multiplied that ratio by the capacity of the Projects O and R.

revenue in years for which Connecticut is short of forward reserves or capacity. (See Section IV.D)

5. We weighted the results across scenarios to exclude the implausible Scenarios 5, 8, and 9 (and for balance, Scenarios 6 and 7), as in the table on page 22.

Otherwise, our data are taken entirely from LEI's results.

The results of these corrections are summarized in the table below, which follows the structure of Section 6.4 of the Report.

Project Results: Corrected Benefits, Corrected Costs, Plausible Scenarios

Portfolio Name	Portfolio 89	Project E	Project O	Project R
Projects	E, D, O, R	409	851	993
Portfolio Mix	1 CC, 1 EE, 2 Peaker	CCGT	Peaker	Peaker
Portfolio Size (Total MW)	787	620	66	96
Average Benefits - ENERGY ($/kW)	$456	$458	$42	$22
Average Benefits - ENERGY ($ million)	$301	$280	$3	$2
Average Benefits - CAPACITY ($/kW)	$0	-	-	-
Average Benefits - CAPACITY ($ million)	$0	-	-	-
Average Benefits - LFRM ($/kW)	$4	$2	($37)	$40
Average Benefits - LFRM ($ million)	$2	$1	($2)	$4
Average Benefits ($/kW)	$460	$459	$5	$62
Average Benefits ($million)	$303	$281	$0	$6
Average Costs ($/kW)	$579	$542	($14)	$410
Average Costs ($ million)	$346	$301	($1)	$39
Average Net Benefits (NB) ($/kW)	($120)	($82)	$20	($348)
Average Net Benefits (NB) ($ million)	($43)	($20)	$1	($33)

Portfolio 89, Project E and Project R have negative net benefits for the base case and on average over all baseline scenarios with just these adjustments. Other corrections of the modeling—such as reductions in energy benefits to reflect the impact of ARRs and to reflect the effect of avoiding some non-Connecticut combined-cycle capacity—would result in Portfolio 89 and Project E looking even worse than shown above.

Q: How important is the weighting of scenarios in explaining the differences between your results and LEI's?

A: The scenario weightings are material. Using all of LEI's weights for all nine scenarios—including the implausible Scenarios 5, 8, and 9—would show Project E as having $19 million in net benefits.[60]

Q: What do your results indicate regarding Project O?

A: Project O has negative costs and positive net benefits.[61] The actual benefits will depend on what else is built in Connecticut, especially in terms of LFRM resources. Overall, considering the price hedge of Project O, its contribution to reliability, and the progress it makes toward reaching the Connecticut forward-reserve requirement, we believe that Project O is an appropriate commitment for Connecticut consumers.

V. Recommendations for Future RFPs

Q: If the Department is in the situation of reviewing the structure or results of a future RFP for new resources, what lessons should it learn from the problems with the LEI analysis?

A: First, the analysis should address the key issues in this case, such as:

- how much LFRM capacity is likely to be added in response to market prices;
- whether additional LFRM capacity from the RFP would increase or decrease costs to Connecticut load; and

[60] This net benefit is a tiny percentage of the Project's costs.

[61] The negative costs result from the high FCM prices credited to the contracts in Scenario 4.

- whether increasing LFRM costs to increase reliability would be in the public interest.

Second, the Department should insist on consistent assumptions for scheduling resource additions: the rules used in determining how much generic capacity would be added without RFP contracts should be consistent with the rules used to determine the amount of generic additions with RFP contracts included.

Third, any scenario analysis should use plausible scenarios and reasonable weighting of the probabilities of those scenarios. It is reasonable to give greater weight to some adverse outcomes than their probability alone could justify, to reflect some risk aversion, but overall the scenarios and the weights must be reasonable.

Fourth, if the Department allows contracting for energy-efficiency projects (which may not be necessary or prudent), it should impose stringent standards and continuing oversight to ensure that the energy-efficiency projects are actually beneficial.

Fifth, the Department should discourage arbitrary rejection of projects prior to consideration of their benefits.

Sixth, the Department should not allow the use of factor-weighting approaches (as LEI uses for emissions and the overall other-factor weight) in which each project's score can vary with the scores of other bids.

Seventh, the Department should attempt to structure any future RFP so that an independent third party is able to review the RFP evaluation process as it occurs. As we demonstrate through this testimony, LEI made a number of errors that should and could have been caught and corrected prior to the issuance of the Report. In this case, OCC was not given access to the evaluation process until after the Report was filed and the utilities were in the process of working out contracting details.

Q: Does this conclude your testimony?

A: Yes.