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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Connecticut Municipal Electric Energy Cooperative and Richard Blumenthal, Attorney General for the State of Connecticut, Complainants, v. Milford Power Company, LLC, and ISO New England Inc., Respondents.	Docket No. EL08-___

COMPLAINT OF CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE AND RICHARD BLUMENTHAL, ATTORNEY GENERAL FOR THE STATE OF CONNECTICUT, SEEKING IMMEDIATE TERMINATION OF RELIABILITY MUST RUN AGREEMENT AND REQUESTING FAST TRACK PROCESSING

1. Pursuant to Section 206 of the Federal Power Act ("FPA"), 16 U.S.C. § 824e, and Rule 206 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.206, the Connecticut Municipal Electric Energy Cooperative ("CMEEC") and Richard Blumenthal, Attorney General for the State of Connecticut ("CTAG") (collectively, "CMEEC/CTAG" or "Complainants") file this complaint against Milford Power Company, LLC ("Milford") and, to the extent necessary, ISO New England Inc. ("ISO" or "ISO-NE").[1] Because of the importance of the matters at issue and because

[1] As explained *infra*, CMEEC/CTAG are willing to withdraw this Complaint as concerns the ISO if the Commission finds that it is unnecessary to bring suit against ISO to obtain the relief sought herein.

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refund protection under FPA Section 206 might otherwise lapse before the matters raised herein are resolved, CMEEC/CTAG request that the Commission use its "Fast Track" processing procedures for this Complaint.

2. CMEEC/CTAG seek an order from the Commission terminating the "Cost-Of-Service Agreement by and between Milford Power, LLC and ISO New England Inc.," which is a "Reliability Must Run" ("RMR") Agreement that went into effect pursuant to Commission authorization on November 3, 2004. This RMR Agreement has been designated as Milford Power, LLC FERC Electric Tariff, Original Volume No. 2. *Milford Power Company, LLC*, 110 F.E.R.C. ¶ 61,299, *reh'g denied and clarification granted*, 112 F.E.R.C. ¶ 61,154 (2005) ("*Milford I*"). As explained *infra*, the RMR Agreement provides cost-of-service rate treatment for Milford's two-unit, 555 MW, combined-cycle generating facility ("Milford Station").

3. Termination of the Milford RMR Agreement is appropriate because cost-of-service rate treatment is no longer needed to keep the Milford Station in operation, and, absent such need, the continued use of an expensive, market-disrupting RMR agreement is not just and reasonable. As explained in the attached Affidavit of Brian E. Forshaw ("Forshaw Affidavit"), CMEEC's Director of Energy Markets, the combination of Milford's Forward Capacity Market ("FCM") transition payments, inframarginal revenue, and other available revenue is more than enough to cover Milford's "Facility Costs," and thus to enable Milford to operate without an RMR agreement. As such, Milford is ineligible to continue receiving guaranteed full cost recovery under the existing RMR agreement, which should be terminated immediately.

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4. Because full cost-of-service rates — including a return of and on investment — may no longer be needed to keep the Milford units in operation, the Commission should initiate a Section 206 proceeding to investigate the justness and reasonableness of the continuation of the Milford RMR Agreement, and should set the earliest possible refund effective date. CMEEC/CTAG request that the Commission process this Complaint and the ensuing proceeding under its "fast track" standards, in order to maximize the chances that Milford's RMR agreement can be terminated before the completion of the 15-month refund period established by Section 206(b), 16 U.S.C. § 824*e*(b).

5. We note that the analysis presented below regarding Milford's costs and revenues is, of necessity, an estimate based upon the best available public information. If the Commission concludes that the estimated data contained herein are insufficient to support termination of the RMR Agreement, we ask the Commission to: (a) issue the Model Protective Order in this proceeding; (b) direct Milford and/or the ISO to produce (subject to the Model Protective Order) the non-public data described *infra* concerning Milford's market revenues and RMR Agreement payments since the RMR Agreement went into effect in November 2004; and (c) provide CMEEC/CTAG with an opportunity to evaluate and comment upon these data before the Commission takes further action.

SUMMARY OF COMPLAINT

6. The Commission has held repeatedly that RMR agreements are a "last resort"[2] that should be in place for as brief a time period as possible,[3] that should be

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[2] *E.g.*, *Norwalk Power, LLC*, 120 F.E.R.C. ¶ 61,048, P 2 & n.3 (2007) ("*Norwalk Power"*), *reh'g pending*; *Berkshire Power Co., LLC*, 112 F.E.R.C. ¶ 61,253, P 22 (2005) ("*Berkshire I"*) ("[A]n RMR agreement should be viewed as a tool of last resort for a generator."); *Devon Power LLC*, 110 F.E.R.C. ¶ 61,315, P 40

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eliminated as soon as reasonably possible,[4] and that must not become a "crutch" for generator cost recovery.[5] Nonetheless, as this Commission well knows, Connecticut consumers have paid (and continue to pay) many millions of dollars to generators that opted out of the region's "restructured" and "competitive" markets and opted into full cost-of-service, RMR agreements. During the current year alone, Connecticut consumers will pay charges imposed pursuant to RMR agreements covering roughly 2700 MW of Connecticut-based generation, at rates set based upon aggregate annual fixed revenue requirements totaling nearly $240 million.

7. The Commission's "Order on Contested Settlement Agreements," *Milford Power Company, LLC*, 119 F.E.R.C. ¶ 61,167 ("*Milford II*"), *reh'g denied,* 121 F.E.R.C. ¶ 61,042 (2007), accepted in part a Settlement Agreement concerning the rates to be imposed under the Milford RMR agreement, while continuing to acknowledge that the agreement should be terminated if and when circumstances warrant. The Commission rejected the proposed inclusion in the Settlement Agreement of a *Mobile-Sierra* provision that would have insulated Milford's RMR agreement against challenge and, instead, agreed with CMEEC and the CTAG that future review of Milford's RMR agreement would be under the "just and reasonable" standard rather than "public interest" standard. *Milford II* at P 31. Moreover, the Commission stated specifically that, if Milford's financial circumstances change sufficiently to eliminate the need for an RMR agreement,

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(2005) ("The Commission has stated on several occasions that it shares the concerns… that RMR agreements not proliferate as an alternative pricing option for generators, and that they are used strictly as a last resort so that units needed for reliability receive reasonable compensation."); *Devon Power LLC*, 103 F.E.R.C. ¶ 61,082, P 31 (2003) (finding "that RMR agreements should be a last resort").

[3] *New England Power Pool*, 103 F.E.R.C. ¶ 61,304, P 41 (2003).

[4] *Id.*

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parties may "file a separate section 206 complaint proceeding" seeking to terminate the Agreement. *Id.* P 48; *see also* 121 F.E.R.C. ¶ 61,042 at n.41.

8. CMEEC/CTAG demonstrate herein that there is good reason to terminate the Milford RMR Agreement immediately. Since December 1, 2006, Milford has since been receiving FCM "transition payment" revenues that we estimate exceed $17 million per year.[6] Milford receives these amounts, subject to availability adjustments, in addition to any inframarginal or other revenue that the Company receives through the market.

9. The FCM transition payments follow — and supplement — significant increases during 2005 and 2006 in the level of energy market and ancillary service revenues available to New England generators. Beginning in 2003, and each year thereafter, the ISO's "Annual Markets Report" has calculated the maximum net revenue (*i.e.*, net of variable costs) available to a hypothetical natural gas-fired combined-cycle unit in New England at Hub-based prices. As explained in the Forshaw Affidavit, on an annual dollars per-MW basis the net revenue available to a hypothetical gas-fired combined-cycle unit in New England — *excluding* capacity revenues — jumped from $74,000/MW and $64,350/MW in 2003 and 2004, respectively, to $113,843/MW and $103,659/MW in 2005 and 2006, respectively. *See* Forshaw Aff. Ex. No. 2 (excerpts from ISO Annual Markets Reports for 2003-06). The advent of FCM transition payments of approximately $36,000/MW per year brings the 2005 and 2006 figures up to $150,043/MW and $140,048/MW per year. By way of comparison, ISO's 2004 Annual

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[5] *Bridgeport Energy, LLC*, 118 F.E.R.C. ¶ 61,243, P 41 & n.34 (2007) ("*Bridgeport Settlement Order*").

[6] The FCM was created pursuant to a Settlement Agreement that was approved by the Commission in 2006. *Devon Power LLC*, 115 F.E.R.C. ¶ 61,340, *order on reh'g*, 117 F.E.R.C. ¶ 61,133 (2006), *appeal pending*.

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Market Report estimated that the annual non-variable costs of a new combined-cycle plant (*i.e.*, Facility Costs *plus* depreciation, debt repayment, and return on equity) ranged from $100,000/MW to $125,000/MW. *Id.* at 8. Milford's Facility Costs are between $54,000/MW and $74,000/MW, depending on whether debt service is included in the Facility Cost numerator. *See* Forshaw Aff. Ex. No. 1 (spreadsheet setting forth Milford's Facility Costs with and without debt service; dividing by 555 MW yields dollars/MW figures).

10. While CMEEC/CTAG are not permitted access to the generator-specific ISO settlement information needed to determine with certainty the level of market revenues earned by Milford since its RMR Agreement became effective, there are solid grounds based on publicly available data to assert — and for the Commission to find — that Milford is currently earning "market" revenues that more than cover any reasonable estimate of Milford Station's "Facility Costs." In these circumstances, the Milford RMR agreement should terminate forthwith.

11. Alternatively, if the RMR Agreement is not terminated summarily, CMEEC asks that, at a minimum, Milford's "financial eligibility" for its RMR Agreement be set for hearing. In connection with this action, CMEEC/CTAG request that the Commission direct Milford and ISO to produce data regarding the inframarginal revenues earned by Milford Station while operating under the RMR Agreement since its inception — including, but not limited to, the payments made to Milford under the RMR Agreement and the revenue credits that were used in calculating these payments. These data, which are in the possession of the Respondents but are not available to us, will be used to verify what CMEEC/CTAG believe can be demonstrated from publicly-available

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information: *i.e.*, that Milford no longer meets the Facility Cost test for a generating resource to be RMR agreement-eligible. Once the data have been produced, CMEEC/CTAG ask that they be given an opportunity to review and comment upon them before the Commission rules on the issues raised in this Complaint.

I. PARTIES

12. The parties to this proceeding are:

A. Complainants

13. **CMEEC** is a political subdivision of the State of Connecticut created in 1976 pursuant to Conn. Gen. Stat. §§ 7-233a *et seq*. It is a non-profit municipal joint action electric agency which provides the power supply requirements, at wholesale, of six municipal electric department participants with retail service territories in Connecticut (five of whom are members of CMEEC) as well as several other Connecticut customers purchasing power at wholesale.[7]

14. CMEEC is an active participant in the New England wholesale power markets, a NEPOOL Participant, and a load-serving entity of long-standing. As a representative of Connecticut-based, load-serving entities participating in New England's wholesale electric generation markets, CMEEC and its members are obligated to pay a share of the charges imposed upon Connecticut consumers for payments imposed under the Milford RMR Agreement.

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[7] Specifically, CMEEC provides power supply service to members: the City of Norwich Public Utilities, the City of Groton Department of Utilities, the Borough of Jewett City Department of Public Utilities, the South Norwalk Electric Works, the Third Taxing District of the City of Norwalk Electric Department; and to a participant: the Town of Wallingford Department of Public Utilities – Electric Division; and to customers: the Bozrah Light & Power Company (owned by the City of Groton Department of Utilities) and the Mohegan Tribal Utility Authority.

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15. The CTAG is the chief legal officer of the State of Connecticut, and is an elected Constitutional officer of the State. Among the CTAG's responsibilities are interventions in various types of proceedings to protect the State, the public interest and the people of the State of Connecticut, and assuring the enforcement of a variety of laws of the State of Connecticut, including Connecticut's Unfair Trade Practices Act and Antitrust Act, so as to promote the benefits of competition and to assure the protection of Connecticut's consumers from anti-competitive abuses.

16. Since November 2004, Connecticut consumers (including those served by CMEEC members) have made payments to ISO for charges imposed under the Milford RMR Agreement totaling approximately $115 million.

B. Respondents

17. ***Milford***, a Delaware limited liability company, is the owner of an approximately 555 MW, combined-cycle electrical generating facility consisting of two units, known collectively as Milford Station. The "Winter Claimed Capability" of Unit No. 1 is approximately 267 MW; the corresponding figure for Unit No. 2 is 288 MW. Milford Station is located in New Haven County, Connecticut.

18. Milford is a party to the Milford RMR Agreement.

19. ***ISO-NE*** is a FERC-jurisdictional "public utility" and a Commission-approved "Regional Transmission Organization" serving the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO is an independent, not-for-profit corporation formed in 1997. ISO provides minute-to-minute reliable operation of New England's bulk electric power system, providing centrally dispatched direction for the generation and flow of electricity across

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the region's interstate high-voltage transmission lines; development, oversight and administration of New England's wholesale electricity marketplace; and management of comprehensive bulk electric power system and wholesale markets' planning processes.

20. ISO-NE has been included as a Respondent out of an abundance of caution. As the purchaser of services furnished by Milford, ISO is a party to the Milford RMR Agreement. CMEEC/CTAG are uncertain whether it is necessary to name the purchaser under the Agreement as a "Respondent" in order to obtain the Section 206 relief sought in this Complaint. To the extent the Commission determines that ISO-NE need not be joined as Respondent, CMEEC/CTAG ask that the Commission consider the instant Complaint withdrawn as to ISO-NE.[8]

II. COMMUNICATIONS

21. All communications concerning this filing should be addressed to:

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[8] We note that certain data in the possession of the ISO may be needed to adjudicate the issues raised in the Complaint. ISO should be retained as a Respondent if it is necessary to do so to facilitate the production of the needed data.

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III. BACKGROUND

22. On November 1, 2004, as supplemented on January 21, 2005, Milford initiated Docket No. ER05-163-000 by submitting a proposed, unexecuted RMR agreement with ISO-NE covering Milford Station. The RMR agreement provides for Milford to collect a monthly payment based upon the difference between the revenues it earns "in the market," and the monthly share of its Annual Fixed Revenue Requirement ("AFRR"). In return, Milford participates in the market in accordance with the restrictions set forth in the RMR Agreement, including as to stipulated bidding and unit availability.

23. In *Milford I*, the Commission accepted the proposed RMR Agreement for filing, suspended it for a nominal period, made it effective November 3, 2004, subject to refund, and set it for hearing and settlement judge procedures. The Commission held the hearing in abeyance pending the outcome of settlement judge procedures.

24. On April 19, 2006, Milford, ISO-NE, the Connecticut Department of Public Utility Control ("CT DPUC"), and the Connecticut Office of Consumer Counsel ("CT OCC") (collectively, "Settling Parties") filed a Joint Offer of Partial Settlement ("Partial Settlement Agreement"), which was intended to resolve all issues in the proceeding, except for Milford's cost-of-service under its RMR Agreement. Following

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further negotiations, the Settling Parties submitted a second Settlement Agreement (the "Defined COS Settlement Agreement") on October 27, 2006, which included their agreement concerning the cost-of-service to be used to set rates under the Milford RMR Agreement.

25. CMEEC and the CTAG filed separate comments opposing the Partial Settlement Agreement and the Defined COS Settlement Agreement. CMEEC objected to the Settling Parties' proposal that future challenges to the Milford RMR Agreement be subject to the "public interest" standard rather than the "just and reasonable" standard set forth in Section 206 of the Federal Power Act. The CTAG joined in raising this concern, and filed separate comments disputing the eligibility of Milford Station for an RMR agreement.

26. On May 18, 2007, the Commission issued *Milford II*, in which it rejected the Settling Parties' proposal to require that RMR agreement eligibility challenges brought by non-signatories be evaluated under the "public interest" standard of review. Instead, the FERC found that "any challenges to the RMR agreement by non-parties under section 206 of the FPA shall be reviewed by the Commission under the just and reasonable standard." *Id.* P 31.

27. The Commission also addressed the CTAG's challenge to Milford's eligibility for the RMR agreement. In its comments on the settlements, the CTAG alleged, *inter alia*, that initiation of the "transition payments" under the FCM would lead to an improvement in Milford's financial status, such that Milford "will most likely fail to qualify for an RMR agreement under the Commission's Facility Costs Test." *Milford II* at P 33.

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28. The Commission rejected the CTAG's objections regarding Milford's initial eligibility for an agreement, finding that they had been resolved by previous Commission orders in the *Milford* proceeding, *id.* P 46 (footnotes omitted). However, the Commission noted that its prior orders "have not … addressed whether the transition payments Milford will receive under the LICAP/FCM Settlement will result in Milford becoming financially ineligible for the RMR agreements." *Id.* P 47. The Commission went on to state:

> Although the Connecticut Attorney General has raised the continuing eligibility issue here, the issue of whether transition payments will result in Milford becoming financially ineligible for continuing RMR treatment is beyond the scope of this settlement proceeding …. Furthermore, the Connecticut Attorney General's unsupported claim that the transition payments render Milford financially ineligible for the RMR agreement is not directed to whether the Settlement Agreements are just and reasonable.

Id. P 47.

29. While the Commission denied the CTAG's challenge to the RMR agreement at that time, the Commission specifically noted that it did so because the question of continuing eligibility was beyond the scope of the two settlement agreements at issue. *Id.* P 48. In other words, the Commission held that its previous orders had not addressed whether the transition payments Milford will receive under the FCM Settlement will result in the Milford Station becoming financially ineligible for an RMR agreement. *Id.* P 47. The Commission then stated that "if the Connecticut Attorney General has evidence indicating that the transition payments will render Milford financially ineligible for an RMR agreement, he may file a separate section 206 complaint proceeding." *Id.* P 48 & n.92. In issuing this ruling, the Commission cited its

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decision in *Blumenthal v. ISO New England, Inc.*, 117 F.E.R.C. ¶ 61,038, P 71 (2006), holding that "to the extent that any party feels that an RMR agreement is no longer necessary (especially in light of transition payments under the FCM Settlement Agreement), that party is free to file for relief with the Commission under section 206." On rehearing of *Milford II*, the Commission reiterated that "if [a party] has evidence indicating that the transition payments will render Milford financially ineligible for RMR treatment, such evidence should be offered in a separate section 206 complaint." 121 F.E.R.C. ¶ 61,042 at n.41.

30. This is the first complaint filed with the Commission seeking to terminate an RMR agreement on financial eligibility grounds following the advent of FCM transition payments. However, in other recent cases involving *proposed* RMR agreements, the Commission has recognized that the receipt of FCM transition payments, in addition to other revenues, may eliminate a generator's financial need for an RMR agreement, and it has set for hearing all issues related to financial eligibility. *See Bridgeport Energy, LLC*, 118 F.E.R.C. ¶ 61,243, PP 61-62 (2007); *Norwalk Power* at P 27; *Mystic Development, LLC*, 116 F.E.R.C. ¶ 61,168, P 30 (2006).

31. If the Commission does not terminate Milford's RMR agreement on the basis of the evidence and arguments presented in this Complaint, it should similarly set for hearing all matters related to Milford's continued financial eligibility for such an agreement.

IV. STATEMENT OF FACTUAL AND LEGAL BASES FOR REQUESTED RELIEF

32. CMEEC/CTAG assert that the Milford RMR Agreement should be terminated immediately because it appears that Milford Station is recovering sufficient

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market revenues to enable it to cover its Facility Costs without the RMR Agreement.[9] As explained below, this assertion is consistent with data provided by Milford to the Commission. We first review below the Commission-created RMR agreement eligibility criteria, and then explain why the application of those criteria to the facts at issue here justifies an order terminating the Milford RMR Agreement immediately.

A. An RMR Agreement Is A "Last Resort" Option To Be Kept In Place No Longer Than Absolutely Necessary

33. The Commission has explained repeatedly that generators operating in ostensibly competitive markets are not entitled to a guarantee that they will recover their full cost of service, but only to a reasonable *opportunity* to recover their costs in the market. This means that the Commission will not even entertain the notion of approving a proposed RMR agreement absent a demonstration that the financial situation facing a generating resource is sufficiently dire. As explained in the *Bridgeport Settlement Order*, 118 F.E.R.C. ¶ 61,243, P 60 (2007), the basis for RMR agreement approval is "the concern that, absent an RMR contract, the facility will be unable to continue operation." The reason for the Commission's reluctance to approve RMR agreements is also well-known; the Commission has repeatedly expressed dissatisfaction with RMR agreements as "non-market mechanisms," and has determined that RMR agreements

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[9] We use the phrase "market" revenues for ease of reference and to distinguish non-RMR agreement revenues from those received under the RMR agreement. However, we note that Milford's "market" revenues, or non-RMR agreement revenues, are not limited to the revenues it receives through any particular ISO-operated market(s). Generators may have other potential revenue sources (such as bilateral contracts, contract buyout payments, or hedging arrangements) that contribute to its ability to operate without an RMR agreement. We use the term "market" revenue inclusively to encompass all revenues received by or attributable to the generator under an RMR agreement, other than revenues derived from the RMR agreement itself.

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should be used only as a last resort because of their negative impacts on the market. *E.g.*, *Milford II* at P 31 & n.51.[10]

34. There are generally two criteria that must be met in order for a generating resource to be eligible for RMR Agreement relief. First, there must be a determination that the generating resource is needed for reliable system operation. This is a determination made in the first instance by the ISO, and subject to review by the Commission. *E.g.*, *Pittsfield Generating Co., L.P.*, 119 F.E.R.C. ¶ 61,001, P 25 (2007). Second, the Commission must determine whether an RMR agreement is needed in order to keep the facility in operation. In order to make that determination, the Commission compares a generating unit's historic market revenues to its "costs ordinarily necessary to keep a facility available," or "Facility Costs." *Mystic Development, LLC*, 116 F.E.R.C. ¶ 61,168, P 20 & n.10 (2006). The Commission has determined that a resource's "Facility costs" generally include fixed O&M, A&G, and taxes. *Id.* In addition, the Commission has held (in our view, erroneously) that debt service payments may be included as facility costs — at least in some cases. In *Mystic Development, LLC*, the Commission held that it will "review each RMR agreement on a case-by-case basis to determine whether particular debt service payments should be considered as Facility Costs." 116 F.E.R.C. ¶ 61,168 at P 25; *see also Norwalk Power* at P 27.

35. Moreover, the Commission has made clear that the Facility Cost Test does not establish the floor for a merchant generator's market revenue in a given year. *E.g.*, *Consolidated Edison Energy Massachusetts, Inc.*, 112 F.E.R.C. ¶ 61,263, P 36 (2005) ("[I]t is not the position of the Commission that cost-of-service agreements should be the

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[10] *See also* the cases cited in nn.2-5, *supra*.

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recovery floor for generators that are unable to earn a profit for a given year."); *Bridgeport Energy, LLC*, 112 F.E.R.C. ¶ 61,077, P 39 (2005). Instead, consistent with the Commission's treatment of RMR agreements as "last resort" measures, the Facility Cost Test focuses on whether a generator has *persistently* failed to recover its facility costs in the market. As the Commission has explained:

> The purpose of the historical cost recovery assessment is to determine whether an RMR contract is necessary to keep Bridgeport available to provide reliability service. This consideration is not tied to any specific date, but to the general ability of Bridgeport to recover its costs. *It is reasonable and expected in a competitive market that there will be periods where full cost recovery is not realized.*

Bridgeport Energy, LLC, 113 F.E.R.C. ¶ 61,311, P 47 (2005) (emphasis added).

36. Consistent with their "transitional" and "last resort" nature,[11] the Commission has ruled that RMR agreements are subject to continuing challenge. Thus, a generating resource's eligibility for an RMR agreement can always be attacked where it can be shown that (a) the resource is no longer needed for reliability; or (b) the resource is able to earn sufficient revenues "in the market" to cover at least its Facility Costs. *E.g.*, *Bridgeport Settlement Order* at P 62; *Milford II* at P 48.

37. More specifically, the Commission has made clear, both in *Milford II* and elsewhere, that the transition payments available to generators under the now-approved FCM settlement (and related market rules) should be taken into account in assessing a generator's financial need for an RMR agreement. *E.g.*, *Bridgeport Settlement Order* at n.50 ("going forward, transition payments must be included in the Facility Costs Test that

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[11] *Norwalk Power* at P 28 ("On numerous occasions, the Commission has stated its view that RMR agreements represent 'tools of last resort' and are transitional in nature.").

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will be addressed in the hearing"); *Norwalk Power* at P 27 & n.18. Under the FCM settlement and related market rules, generating resources will be paid fixed, per-kW capacity rates during the period between December 1, 2006 and June 1, 2010, the date for the commencement of the first "Commitment Period" under the FCM.[12] The transition payments range from $3.05 per kW-month for the 2006-2007 timeframe, to $4.10 per kW-month for the 2009-2010 time frame. *Norwalk Power* at n.18.

B. Publicly-Available Data Demonstrate That Milford Is Recovering The Station's "Facility Costs" Through "Market" Revenues

38. While CMEEC/CTAG lack access to non-public Company or ISO data concerning the payments made by ISO to Milford and the market revenues earned by Milford during the term of its RMR Agreement, it is possible to estimate these amounts based upon publicly-available information. As explained in the attached affidavit of Brian E. Forshaw, Complainants have estimated the level of inframarginal revenues earned by Milford during the 2005-2007 period using data extracted from Milford's Electronic Quarterly Reports ("EQR").[13] Forshaw Aff. at 4, ¶ 9. These data, sorted into relevant categories, are included in spreadsheet form as Exhibit No. 1 to Mr. Forshaw's Affidavit.[14] The data show that, had the FCM transition payments been available to Milford prior to December 1, 2006, the Company would not have needed an RMR agreement in order to recover its Facility Costs. *Id.* at 4, ¶ 10. Thus, absent a significant,

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[12] The Milford RMR Agreement will terminate on that date, if it is not terminated before that time.

[13] http://www.ferc.gov/docs-filing/eqr/data/spreadsheet.asp.

[14] Mr. Forshaw has grouped the two Milford units together for purposes of conducting these analyses. Mr. Forshaw explains that data on the estimated number of starts were based on an assumption of four (4) starts per month, which would comport with a generation cycle of operating during the week and shutting down on the weekend. Forshaw Aff. at 5, ¶ 13. Ex. No. 1 to Mr. Forshaw's Affidavit is a pdf summarizing Mr. Forshaw's analysis of Milford's revenues and Facility Costs. The spreadsheet from which Ex. No. 1 was produced will be made available to parties upon request and, to the extent necessary,

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negative change in market circumstances, there are sound reasons to believe that the advent of FCM transition payments renders Milford Station ineligible for RMR agreement coverage. Indeed, the data culled by Mr. Forshaw from the EQRs indicate that Milford Station recovered its Facility Costs during 2006 even *without* taking the FCM transition payments into account. *Id.*

39. Mr. Forshaw explains that his analysis estimates the net margin earned by Milford Station during each year of the historical period (from 2005 through September 2007) by using (1) EQR data concerning Milford's energy revenues, uplift payments, and supplemental reserve payments; (2) EQR data regarding Milford Station's generation levels; and (3) estimates of Milford's generation costs, derived by Mr. Forshaw through the use of the stipulated bid parameters contained in the Milford RMR Agreement and index data (including both publicly available and commercially-obtained proprietary data) for the relevant months. *Id.* at 4-5, ¶¶ 11, 12.[15] The monthly estimate of inframarginal revenues is the difference between the monthly estimated energy payments and the monthly estimated total cost. *Id.* at 5, ¶ 14.

40. Mr. Forshaw explains that he has added estimated transition payments to the estimated inframarginal revenues for 2005, 2006, and the first nine months of 2007. This adjustment is necessary in order to provide an accurate picture of whether Milford Station remained financially eligible for an RMR agreement as of December 1, 2006.[16]

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upon adoption of a protective order.

[15] Mr. Forshaw explains that per-start cost data were based on parameters stated in the Milford RMR Agreement. *Id.* at 5, ¶ 13.

[16] Through May 31, 2008, the FCM transition payment rate is $3.05/kW per month, which amounts to roughly $17 million per year for the Milford Station, excluding any availability adjustments. From June 1, 2008, though May 31, 2009, the FCM transition payment rate increases to $3.75/kW per month. From

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41. Mr. Forshaw then compared this combination of inframarginal revenues and transition payments with Milford's estimated Facility Costs. The estimate of the two units' Facility Costs is culled from data provided by Milford as part of its initial filing in Docket No. ER05-163-000; specifically, the information is taken from the Affidavit of Alan C. Heintz, a consultant to Milford who submitted an affidavit as part of Milford's application for RMR agreement approval. Forshaw Aff. at 5, ¶ 16. Mr. Forshaw's analysis shows that, during 2005, Milford's combination of inframarginal revenues and transition payments (had they been available) would have totaled roughly $41.9 million, which was significantly in excess of the $29.8 million figure for Facility Costs gleaned from Mr. Heintz's affidavit. *Id.* at 6, ¶ 17.

42. For 2006, Mr. Forshaw estimates that Milford's inframarginal revenues alone, exclusive of FCM transition payments, totaled nearly $34 million and by themselves exceeded the Station's Facility Costs. The combination of inframarginal revenues and transition payments amounted to more than $51 million, which was roughly $22 million more than the applicable Facility Costs.

43. This trend appears to be continuing into 2007, as data for the first nine months of the year show that the combination of Milford's inframarginal revenues and transition payments is substantially in excess of a nine-month share of the annual Facility Costs. The sum of Milford's estimated inframarginal revenue and FCM transition payments during the first nine months of 2007 was approximately $38.4 million, compared to Facility Costs of $22.4 million during the same period. *Id.* at 6, ¶ 19.

June 1, 2009, though May 31, 2010, the rate will be $4.10/kW per month. These rate increases are not reflected in Mr. Forshaw's analysis but will further improve Milford's financial performance over time.

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44. Mr. Forshaw notes that, while the 2005 and 2006 data are not current, there is no reason to believe that Milford's financial performance will be worse in the near future than it was in the recent past. Milford is now bidding into the market under the RMR Agreement using stipulated bid parameters that are intended to approximate the Station's marginal costs. As such, Mr. Forshaw notes that this is a "dispatch maximizing" strategy, which should result in the Station being dispatched as often as is economically rational. Assuming the RMR Agreement were terminated, Milford could continue to bid the unit into the markets on the same basis, with presumably equivalent results. In addition, the FCM transition payments received by Milford will increase over time as the FCM transition payment rate increases.

45. Mr. Forshaw states that his Facility Cost figures do not include a debt service cost component for Milford. Forshaw Aff. at 7, ¶ 21.[17] As noted above, the Commission "review[s] each RMR agreement on a case-by-case basis to determine whether particular debt service payments should be considered as Facility Costs." *Mystic Development, LLC*, 116 F.E.R.C. ¶ 61,168 at P 25; *Norwalk Power* at P 27. Here, CMEEC/CTAG lack information about Milford's actual debt service obligations (if any), as Milford's original RMR application (a) preceded use of the Facility Cost test for RMR agreement eligibility, and (b) employed a hypothetical capital structure and cost of debt in its cost-of-service filing. Specifically, with respect to the debt service issue, Mr. Heintz's Affidavit, Exhibit No. ACH-1 to the filing initiating Docket No. ER05-163-000, stated that:

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[17] As demonstrated below, however, Milford's inframarginal revenue and FCM transition payments appear to be sufficient to cover both the Company's Facility Costs and debt service.

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> The Company is proposing to use in this filing a capital structure that is 50% long-term debt and 50% equity, as recently approved by the Commission in similar circumstances. [citation omitted] The long-term cost of debt of 6.60% reflects the most recent reported average yield to maturity for "A" rated electric utilities in the Standard & Poor's Corporate Bond Guide. This is conservative because Milford is much riskier than the average "A" rated utility and 6.60% is well below the actual debt costs incurred by Milford.

Exh. No. ACH-1 at page 6 of 9:7-14.

46. This passage does not demonstrate that Milford is in fact incurring debt service payment obligations of the kind the Commission could consider a part of the Station's Facility Costs. Mr. Heintz's testimony does not indicate the identities of any lenders, the terms and conditions of any purported loans, or any consequences of non-payment. Purported "loans" and related "debt service" payments may be proven, upon examination, to be unsecured "loans" provided by corporate parents or affiliates that amount to equity infusions from the project's owners in substance if not form. Absent detailed information about Milford's financing arrangements — information that is not available to the Complainants — it is impossible either to quantify Milford's actual "debt service" costs or to tell whether those costs qualify as Facility Costs for RMR agreement eligibility purposes.

47. Even assuming *arguendo* that Milford's "debt service" payments are found to be properly includable as part of the Station's facility costs, Mr. Forshaw states that Milford likely would remain ineligible for an RMR Agreement. Forshaw Aff. at 7-8, ¶ 24. Using Milford's 6.60% cost of debt and a rate base that Mr. Heintz calculated as roughly $339.5 million, Mr. Forshaw assumes for the sake of discussion that Milford's debt service costs are roughly $11.2 million. *Id.*

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48. If that debt service cost were included as part of the Station's facility costs, it would not change Complainants' conclusion with respect to RMR agreement eligibility. Mr. Forshaw shows that, when combined with FCM transition payments, Milford's market revenues exceeded the sum of its Facility Costs and debt service by nearly $1 million in 2005, by more than $10 million in 2006, and by more than $7.5 million during the nine months of 2007. *Id.*; Forshaw Aff., Ex. No. 1.

49. As these data make clear, Milford does not need an RMR Agreement in order to recover its Facility Costs and to keep the Milford Station in operation. CMEEC/CTAG therefore request that the Commission issue an order terminating the Milford RMR agreement immediately.

C. The Commission Should Require Milford and ISO to Produce Non-Public Cost and Revenue Data Subject to a Protective Order

50. ISO-NE has taken the position that its Commission-approved "Information Policy" precludes it from releasing unit-specific cost, bid, and revenue data, without authorization from the relevant generator. While Complainants have been able to estimate Milford's Facility Costs, inframarginal revenues, and FCM transition payments from publicly-available data, the most direct evidence regarding Milford's need for an RMR agreement consists of non-public, unit-specific information to which CMEEC/CTAG do not have access. If the Commission does not find Complainants' analysis based upon publicly-available data to be sufficient to demonstrate Milford's ineligibility for an RMR agreement, the Commission should require Milford and ISO to produce, subject to an appropriate protective order, monthly data regarding (a) Milford's Facility Costs, (b) the payments made by ISO to Milford under the RMR agreement, and

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(c) the revenue credits (*i.e.*, non-RMR agreement revenues) applied by ISO New England in calculating the payments to be made to Milford under the RMR agreement.

51. The justification for restricting the availability of unit-specific cost, bid and revenue data — the desire to limit opportunities for collusive pricing — can be satisfied through the entry of an appropriate protective order preventing public disclosure of the requested information and limiting its use to the conduct of this case. Rules adopted for the purpose of protecting the market should not be turned on their head to stifle litigation designed to eliminate unnecessary, market-disrupting cost-of-service agreements.

52. To the extent necessary to facilitate data disclosure, we ask that the Commission issue the Model Protective Order in this proceeding.

V. FAST TRACK PROCESSING REQUESTED

53. Time is of the essence in resolving the issue presented here. First, the Commission itself has expressed concern over the adverse impacts of cost-of-service guarantee contracts on ostensibly competitive markets. These impacts cannot be undone retroactively. Therefore, eliminating RMR agreements for which a generator is no longer eligible should be a matter of first priority for the Commission. Second, Connecticut consumers are overpaying a substantial amount of money on each day that the Milford RMR agreement remains in effect. Absent fast track processing, we are concerned that Milford's agreement may not be terminated within the 15-month refund period established by Section 206 of the Federal Power Act. *See* 16 U.S.C. § 824*e*(b). Fast track processing of the instant complaint is therefore warranted in order to resolve this

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dispute promptly and to avoid the unnecessary and unjust imposition on Connecticut customers of unwarranted cost-of-service payments to Milford.

VI. STATEMENT OF COMPLIANCE WITH SPECIFIC REQUIREMENTS OF RULE 206

54. Rule 206(b)(1): The continued maintenance of the Milford RMR Agreement is contrary to the Commission's eligibility criteria and has therefore become unjust and unreasonable.

55. Rule 206(b)(2): Milford is no longer eligible for RMR agreement coverage. As such, it is no longer just or reasonable for Milford to continue to receive guaranteed cost-of-service payments from ISO under the RMR Agreement, which should be terminated.

56. Rule 206(b)(3): The failure to terminate the Milford RMR Agreement means that Connecticut customers (including those served by CMEEC member systems) will continue to make excessive, unjust and unreasonable payments to Milford. In addition, and as the Commission has stated repeatedly, RMR agreements have deleterious impacts on the market, including suppressing market-clearing prices and deterring investment in new generation. Moreover, the market participants that pay for RMR agreements pay out-of-market prices for the service provided under the RMR agreements, which broadly hinders market development and performance.

57. Rule 206(b)(4): We estimate that Connecticut consumers have paid roughly $115 million in charges under the Milford RMR Agreement during the period January 2005 through September 2007.

58. Rule 206(b)(5): Complainants are unaware of any environmental, safety or reliability impact associated with the termination of the Milford RMR Agreement.

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59. Rule 206(b)(6): The issues presented in this Complaint are not pending in an existing Commission proceeding or in a proceeding in any other forum in which CMEEC or the CTAG is a party.

60. Rule 206(b)(7): CMEEC/CTAG seek immediate termination of the Milford RMR Agreement.

61. Rule 206(b)(8): Complainants have attached to this Complaint the documents in their possession or attainable by them that "support the facts in the complaint." Through the Forshaw Affidavit, the Complainants have presented the facts and information in their possession or attainable by them that document the revenue earned by Milford through participation in the New England markets and that estimate the Facility Costs incurred by Milford in order to remain available to provide service. However, and as explained *supra,* the data presented by Mr. Forshaw are estimates based on data on-file with the Commission and publicly- or commercially-available indices. Complainants' figures are not based upon actual data regarding Milford's costs and revenues because we do not have access to that information. Data on Milford's market revenues, inframarginal revenues, and payments received under the RMR Agreement are not publicly available and, so far as CMEEC/CTAG are aware, are in the sole possession of Milford and ISO. Complainants request that Commission require Milford and ISO to produce these data, which are central to validating our assertion that Milford is earning sufficient revenues through the marketplace to recover at least its "Facility Costs." To the extent that the ISO is no longer a Respondent, we ask that Milford be required to direct the ISO to produce the requisite data.

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62. Rule 206(b)(9): CMEEC/CTAG have not engaged in any dispute resolution process with respect to the matters at issue in this Complaint, though CMEEC and the CTAG participated in the settlement talks that preceded the settlement agreement approved by the Commission in *Milford II.* We do not believe that dispute resolution would be effective in resolving the matters at issue because they involve termination of the Milford RMR Agreement. Presumably, Milford would not agree in settlement to terminate its RMR agreement. Complainants are concerned that devoting substantial time to an ultimately-unsuccessful settlement process could harm Connecticut customers by increasing the likelihood that the 15-month refund period would run before the case can be finally decided. Assuming the Commission believed that settlement talks could resolve or at least narrow the matters at issue, CMEEC and the CTAG would be willing to participate in brief, time-limited settlement discussions for a period up to 30 days.

63. Rule 206(b)(10): A form of Notice is Attachment – to this Complaint.

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VII. RELIEF REQUESTED

64. For the reasons set forth above, the Commission should (1) process this complaint under its fast track procedures; (2) terminate the Milford RMR agreement; and (3) provide any other relief it deems necessary or appropriate.

Respectfully submitted,

/s/ Scott H. Strauss

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December 4, 2007

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Affidavit of Brian E. Forshaw
in Support of Complaint

COMPLAINT OF CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE AND RICHARD BLUMENTHAL, ATTORNEY GENERAL FOR THE STATE OF CONNECTICUT, SEEKING IMMEDIATE TERMINATION OF RELIABILITY MUST RUN AGREEMENT AND REQUESTING FAST TRACK PROCESSING

Filed December 4, 2007

in

FERC Docket No. EL08-___-___

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Connecticut Municipal Electric Energy Cooperative and Richard Blumenthal, Attorney General for the State of Connecticut, Complainants, v. Milford Power Company, LLC, and ISO New England Inc., Respondents.	Docket No. EL08-___

AFFIDAVIT OF BRIAN E. FORSHAW
IN SUPPORT OF COMPLAINT

STATE OF CONNECTICUT) SS:

PERSONALLY appeared before me the undersigned, who, after being duly sworn, states on his oath as follows:

1. My name is Brian E. Forshaw. I am the Director of Energy Markets for the Connecticut Municipal Electric Energy Cooperative ("CMEEC"). My place of business is 30 Stott Avenue, Norwich, Connecticut, 06360-1526.

2. CMEEC is a political subdivision of the State of Connecticut created in 1976 pursuant to Conn. Gen. Stats. §§ 7-233a *et seq*. It is a non-profit municipal joint action electric agency which provides the power supply requirements, at wholesale, of six municipal electric department participants with retail service territories in Connecticut (five of whom are members of CMEEC) as well as several other Connecticut customers purchasing power at wholesale. Specifically, CMEEC provides power supply service to members: the City of

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Norwich Public Utilities, the City of Groton Department of Utilities, the Borough of Jewett City Department of Public Utilities, the South Norwalk Electric Works, the Third Taxing District of the City of Norwalk Electric Department; and to a participant: the Town of Wallingford Department of Public Utilities – Electric Division; and to customers: the Bozrah Light & Power Company (owned by the City of Groton Department of Utilities) and the Mohegan Tribal Utility Authority.

3. My primary responsibilities at CMEEC involve oversight of strategic planning activities, monitoring and evaluating the impact of energy market changes on customers of Connecticut's municipally-owned electric systems, and reporting on such impacts to the CMEEC Board of Directors. In addition, I serve as CMEEC's primary representative in matters pertaining to the New England Power Pool ("NEPOOL") and Independent System Operator New England Inc. ("ISO-NE" or "ISO"). I also serve as the Vice Chair of the NEPOOL Participants Committee representing NEPOOL's Publicly Owned Entity Sector. On behalf of New England's consumer-owned power systems, I have directly participated in virtually all of the restructuring efforts undertaken by NEPOOL since the mid-1980s. This has included service on the NEPOOL Review Committee, the NEPOOL Restructuring Committee, the NEPOOL Operations Committee, the NEPOOL Market Operations Committee, the NEPOOL Markets Committee, the NEPOOL Planning Committee, the NEPOOL Executive Committee, the NEPOOL Members Committee and the NEPOOL Participants Committee, among others.

4. This Affidavit is offered on behalf of CMEEC and Richard Blumenthal, Attorney General for the State of Connecticut ("CTAG"), in support of their Complaint in this proceeding seeking the immediate termination of the "Cost-Of-Service Agreement by and between

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Milford Power, LLC and ISO New England Inc.," which is a "Reliability Must Run" ("RMR") Agreement that went into effect on November 3, 2004.

5. Since November 2004, we estimate that Connecticut customers have made payments to ISO for charges imposed under the Milford RMR Agreement totaling roughly $115 million.

6. CMEEC and the CTAG assert that the Milford RMR Agreement should be terminated immediately because Milford Station appears to be recovering sufficient "market" revenues (*i.e.*, non-RMR agreement revenues) to enable it to cover its "Facility Costs" without the RMR Agreement. This assertion is consistent with and based upon data provided by Milford to the Commission.

7. There are generally two criteria that must be met in order for a generating resource to be eligible for RMR Agreement relief. First, there must be a determination that the generating resource is needed for reliable system operation. Second, the Commission must determine whether an RMR agreement is needed in order to keep the facility in operation. In order to make that determination, the Commission compares a generating unit's historic market revenues to its "Facility Costs." The Commission has determined that a resource's "Facility Costs" are those costs ordinarily necessary to keep a facility available, and generally include fixed O&M, A&G, and taxes. As I understand it, debt service may (or may not) be considered a facility cost depending on the specifics of the arrangement that are in place.

8. CMEEC and the CTAG lack access to non-public Company or ISO data concerning the payments made by ISO to Milford and the market revenues earned by Milford during the

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term of its RMR Agreement. However, it is still possible to estimate these amounts based upon publicly-available information.

9. I was able to estimate the level of inframarginal energy market revenues, uplift, and supplemental reserve payments earned by Milford during the 2005-2007 period using data extracted from the Milford's Electronic Quarterly Reports ("EQR"). As of today, EQR data for Milford are available through the end of September 2007. These data, sorted into relevant categories, have been included in a spreadsheet attachment to my Affidavit (Exhibit No. 1).

10. The data show that, had the FCM transition payments been available to Milford prior to December 1, 2006, the Company would not have needed an RMR agreement in order to recover its Facility Costs. In fact, the data I have culled from the EQRs indicate that Milford Station recovered its Facility Costs during 2006 even *without* taking the FCM transition payments into account.

11. I began my analysis by using EQR revenue data (which my spreadsheet sorts into columns based on the categories used in Milford's reports — specifically, energy revenues, uplift payments,[1] and supplemental reserve [or real-time spinning reserve] payments)[2] to calculate "Total Energy Payment ($)" to Milford for each month. I then used EQR transaction-quantity data (aggregated by month in the "Generation" column of my spreadsheet) to calculate a weighted average "Total Energy Payment ($/MWH) for each

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[1] Milford's EQR separately list "uplift" revenues and "reactive supply and voltage control" payments. In my spreadsheet, I did not include these "reactive supply and voltage control" payments.

[2] Note that "Supplemental Reserve" transactions are distinct from FCM payments, which Milford reports separately as "Capacity" transactions.

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month. I note that historical capacity revenues, which are included in EQR revenue data, were not included in my spreadsheet calculations.

12. I then estimated Milford's generation cost (including both variable costs and start-up costs) through the use of the stipulated bid parameters contained in the Milford RMR Agreement, along with both publicly available and commercially-obtained index data for the relevant months.

13. I note that data on the estimated number of unit starts were based on an assumption of four (4) starts per month, which would comport with a generation cycle of operating during the week and shutting down on the weekend. Per-start cost data were based on parameters stated in the Milford RMR Agreement.

14. I added the "Estimated Variable Cost" and the "Estimated Start-Up Cost" for each month to derive an "Estimated Total Cost" for each month. I subtracted these "Estimated Total Costs" from the EQR-derived "Total Energy Payments" for each month in order to estimate monthly inframarginal revenues, exclusive of capacity revenues.

15. After performing this calculation, I then added the "transition payments" available to the Milford Station pursuant to the "Forward Capacity Market" arrangements in place in New England to the estimated inframarginal revenues for 2005, 2006, and the first nine months of 2007. This adjustment is necessary in order to provide an accurate picture of whether Milford Station remains financially eligible for an RMR agreement as of December 1, 2006.

16. The sum of Milford's "Estimated Inframarginal Revenues" and its "Capacity Revenues @ FCM Transition Rate" represents the margin available to cover Milford's Facility Costs. I estimated the two units' Facility Costs using data culled from the information provided by

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Milford as part of its initial filing in Docket No. ER05-163-000. Specifically, the information is taken from the Affidavit of Alan C. Heintz, a consultant to Milford who submitted an affidavit as part of Milford's application for RMR agreement approval.

17. My analysis shows that, during 2005, Milford's combination of inframarginal revenues and transition payments (had they been available) would have totaled roughly $41.9 million, which was significantly in excess of the $29.8 million figure for Facility Costs gleaned from Mr. Heintz's affidavit.

18. For 2006, as shown on the spreadsheet, I estimate that Milford's inframarginal revenues *alone* — *i.e.*, without FCM transition payments — totaled nearly $34 million, which is itself in excess of the Station's Facility Costs. The combination of inframarginal revenues and transition payments exceeds $51 million, which is roughly $22 million more than the applicable Facility Costs.

19. It appears that this trend is continuing into 2007, as data for the first nine months of the year show that the combination of Milford's inframarginal revenues and transition payments ($38.4 million) is substantially in excess of a six-month share of the annual Facility Costs ($22.4 million).

20. I note that while the 2005 and 2006 data are not current there is no reason to believe that Milford's revenue production in the time period between now and the termination of the RMR Agreement should be markedly different. Milford is now bidding into the market under the RMR Agreement using stipulated bid parameters that are intended to approximate the Station's marginal costs. This is a "dispatch maximizing" strategy, which should result in the Station being dispatched as often as is economically rational. Assuming the RMR Agreement were terminated, Milford could continue to bid the unit

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into the markets on the same basis, with presumably equivalent results. The only difference would be that Milford would not be entitled to recovery of its full cost-of-service, but would instead be limited to its recoveries in and from the markets.

21. The figures on my spreadsheet do not include a debt service cost component for Milford. At this time, I lack sufficient information to conclude whether Milford is in fact paying "interest" on "debt" that should be considered part of the facility cost calculation.

22. With respect to the debt service issue, Mr. Heintz's Affidavit, Exhibit No. ACH-1 to the filing initiating Docket No. ER05-163-000, states (Exh. No. ACH-1 at page 6 of 9, ¶ 15):

> The Company is proposing to use in this filing a capital structure that is 50% long-term debt and 50% equity, as recently approved by the Commission in similar circumstances. [citation omitted] The long-term cost of debt of 6.60% reflects the most recent reported average yield to maturity for "A" rated electric utilities in the Standard & Poor's Corporate Bond Guide. This is conservative because Milford is much riskier than the average "A" rated utility and 6.60% is well below the actual debt costs incurred by Milford.

23. This passage does not demonstrate that Milford is in fact incurring debt service payment obligations as would fall within the scope of the Facility Cost Test. Absent information about the specifics of the "debt" obligations, it is impossible to determine, for example, whether the interest payments on the "debt service" amount to an equity infusion from the project's owners.

24. Even if Mr. Heintz's approximation of the "debt service" component of Milford's cost of service were found to be properly includable as part of the Station's Facility Costs, it would still remain the case that Milford is ineligible for an RMR Agreement. Using Milford's 6.60% cost of debt and a rate base that Mr. Heintz calculated as roughly $339.5 million, it can be assumed for the sake of discussion that the annual debt service component of Milford's proposed cost-of-service was roughly $11.2 million ($339.5 million * 50% *

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6.60%). If this debt service estimate were included as part of the Station's Facility Costs, it would not change my conclusion about whether Milford has been and would be able to recover its Facility Costs without an RMR agreement. Even if my calculated debt service amount were added to Milford's Facility Costs, the Company's 2005 revenue still would have covered its Facility Costs and its 2006 revenue still would have exceeded its Facility Costs by roughly $11 million, and for the first nine months of 2007, by more than $7.5 million.

25. The improvement in Milford's financial performance appears to track larger trends in New England. Each year, the ISO's Annual Markets Report calculates the maximum net revenue (net of variable costs) available to a hypothetical gas-fired combined-cycle generating unit in New England receiving Hub-based prices. Exhibit No. 2 to this Affidavit contains excerpts from the Annual Markets Reports for 2003 through 2006. As shown in the ISO's reports, net energy revenues were $74,000/MW in 2003, $63,000/MW in 2004, $111,635/MW in 2005, and $100,969/MW in 2006. Ancillary service revenues were minimal in 2003 and increased from $1,350/MW in 2004 to $2,600/MW in 2006.

26. At current rates, the ISO estimates that FCM transition payments amount to approximately $36,000/MW per year.

27. Thus, had FCM transition payments been available, the estimated total energy, ancillary service, and capacity revenues available to a hypothetical gas-fired combined-cycle New England generator would have reached approximately $150,000/MW in 2005 and $140,000/MW in 2006, had FCM transition payments been available.

28. By way of comparison, Milford's Facility Costs can be converted into $/MW terms by dividing Milford's Facility Costs ($29.8 million/year without debt service or $41

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million/year with debt service) by its 555-MW capacity. In these terms, Milford's Facility Costs are $54,000/MW (without debt service) or $74,000/MW (with debt service).

29. This concludes my Affidavit.

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Exhibit No. 1 to
Affidavit of Brian E. Forshaw
in Support of Complaint

COMPLAINT OF CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE AND RICHARD BLUMENTHAL, ATTORNEY GENERAL FOR THE STATE OF CONNECTICUT, SEEKING IMMEDIATE TERMINATION OF RELIABILITY MUST RUN AGREEMENT AND REQUESTING FAST TRACK PROCESSING

Filed December 4, 2007

in

FERC Docket No. EL08-___-___

Milford Power Facility Cost Analysis

Summer Capacity Rating: 492.09 MW
FCM Transition Rate: $ 3.05 per kW-month
Assumed EFOR'd value: 5%

	Generation (MWh)	Energy Market Revenues ($)	Uplift Payments ($)	Suppl. Reserve Payment ($)	Total Energy Payments ($)	Total Energy Payment ($/MWh)	Estim. Variable Cost Rate ($/MWh)	Estimated Variable Cost Cost ($)	Estim. # of Starts	Estimated Start-up Cost ($)	Estimated Total Cost ($)	Estimated Inframarginal Revenues ($)	Capacity Revenues @ FCM Transition Rate ($)	Margin to Cover Facility Cost	Facility Cost	Facility Cost including Debt Service	
Jan-05	454,711	$27,353,073	$0	$0	$27,353,073	$60.15	$71.19	$32,370,896	4	$ 112,239	$32,483,135	-$5,130,062	$1,425,831	-$3,704,231	$2,486,748	$ 3,420,748	-$7,124,979
Feb-05	329,091	$18,676,880	$0	$0	$18,676,880	$56.75	$54.14	$17,817,595	4	$ 92,108	$17,909,702	$767,178	$1,425,831	$2,193,009	$2,486,748	$ 3,420,748	-$1,227,739
Mar-05	311,356	$20,286,631	$0	$0	$20,286,631	$65.16	$59.02	$18,375,447	4	$ 97,865	$18,473,312	$1,813,319	$1,425,831	$3,239,150	$2,486,748	$ 3,420,748	-$181,598
Apr-05	162,200	$11,072,312	$0	$0	$11,072,312	$68.26	$58.88	$9,550,962	4	$ 97,707	$9,648,669	$1,423,643	$1,425,831	$2,849,474	$2,486,748	$ 3,420,748	-$571,274
May-05	283,696	$16,494,149	$0	$0	$16,494,149	$58.14	$53.28	$15,114,354	4	$ 91,086	$15,205,440	$1,288,709	$1,425,831	$2,714,539	$2,486,748	$ 3,420,748	-$706,208
Jun-05	247,944	$18,353,762	$0	$0	$18,353,762	$74.02	$58.62	$14,533,565	4	$ 97,391	$14,630,957	$3,722,806	$1,425,831	$5,148,636	$2,486,748	$ 3,420,748	$1,727,889
Jul-05	329,462	$25,954,545	$0	$0	$25,954,545	$78.78	$62.09	$20,455,482	4	$ 101,490	$20,556,972	$5,397,572	$1,425,831	$6,823,403	$2,486,748	$ 3,420,748	$3,402,655
Aug-05	343,046	$31,884,408	$0	$0	$31,884,408	$92.95	$75.42	$25,873,020	4	$ 117,235	$25,990,255	$5,894,153	$1,425,831	$7,319,984	$2,486,748	$ 3,420,748	$3,899,236
Sep-05	260,499	$28,352,973	$0	$0	$28,352,973	$108.84	$95.07	$24,764,885	4	$ 140,434	$24,905,319	$3,447,654	$1,425,831	$4,873,485	$2,486,748	$ 3,420,748	$1,452,737
Oct-05	271,573	$33,083,927	$76,414	$0	$33,160,341	$122.10	$106.02	$28,791,766	4	$ 153,365	$28,945,131	$4,215,209	$1,425,831	$5,641,040	$2,486,748	$ 3,420,748	$2,220,292
Nov-05	150,181	$12,929,245	$50,336	$0	$12,979,581	$86.43	$78.50	$11,789,936	4	$ 120,876	$11,910,813	$1,068,769	$1,425,831	$2,494,600	$2,486,748	$ 3,420,748	-$926,148
Dec-05	125,250	$13,890,453	$176,124	$0	$14,066,577	$112.31	$104.24	$13,056,290	4	$ 151,267	$13,207,557	$859,020	$1,425,831	$2,284,851	$2,486,748	$ 3,420,748	-$1,135,897
Total	3,269,008	$258,332,358	$302,875	$0	$258,635,233	$79.12	$71.12	$232,494,199		$1,373,064	$233,867,263	$24,767,970	$17,109,969	$41,877,939	$29,840,974	$41,048,974	$828,965
Jan-06	151,379	$12,973,905	$48,424	$0	$13,022,329	$86.02	$71.59	$10,836,949	4	$ 112,709	$10,949,658	$2,072,671	$1,425,831	$3,498,502	$2,486,748	$ 3,420,748	$77,754
Feb-06	240,643	$18,656,399	$54,233	$0	$18,710,632	$0.00	$65.71	$15,813,615	4	$ 105,772	$15,919,387	$2,791,245	$1,425,831	$4,217,075	$2,486,748	$ 3,420,748	$796,328
Mar-06	305,161	$19,863,572	$55,702	$0	$19,919,274	$65.27	$58.42	$17,828,132	4	$ 97,162	$17,925,294	$1,993,981	$1,425,831	$3,419,812	$2,486,748	$ 3,420,748	-$936
Apr-06	258,137	$16,420,541	$78,392	$0	$16,498,934	$63.92	$58.79	$15,176,696	4	$ 97,600	$15,274,296	$1,224,638	$1,425,831	$2,650,468	$2,486,748	$ 3,420,748	-$770,280
May-06	205,620	$12,805,996	$56,824	$0	$12,862,820	$62.56	$51.33	$10,554,461	4	$ 88,787	$10,643,248	$2,219,572	$1,425,831	$3,645,403	$2,486,748	$ 3,420,748	$224,655
Jun-06	240,686	$16,736,376	$37,180	$0	$16,773,555	$69.69	$52.08	$12,535,338	4	$ 89,675	$12,625,013	$4,148,543	$1,425,831	$5,574,373	$2,486,748	$ 3,420,748	$2,153,625
Jul-06	273,076	$19,810,783	$16,809	$0	$19,827,593	$72.61	$53.42	$14,587,113	4	$ 91,253	$14,678,366	$5,149,227	$1,425,831	$6,575,057	$2,486,748	$ 3,420,748	$3,154,310
Aug-06	280,740	$21,628,996	$33,033	$0	$21,662,029	$77.16	$62.29	$17,487,551	4	$ 101,730	$17,589,281	$4,072,747	$1,425,831	$5,498,578	$2,486,748	$ 3,420,748	$2,077,830
Sep-06	289,522	$14,606,722	$29,087	$0	$14,635,809	$50.55	$41.61	$12,045,704	4	$ 77,304	$12,123,008	$2,512,801	$1,425,831	$3,938,632	$2,486,748	$ 3,420,748	$517,884
Oct-06	318,726	$19,161,654	$17,853	$57,504	$19,237,011	$60.36	$47.42	$15,114,616	4	$ 84,173	$15,198,789	$4,038,222	$1,425,831	$5,464,053	$2,486,748	$ 3,420,748	$2,043,305
Nov-06	152,635	$10,914,529	$105,917	$855	$11,021,301	$72.21	$60.19	$9,186,688	4	$ 99,246	$9,285,935	$1,735,366	$1,425,831	$3,161,197	$2,486,748	$ 3,420,748	-$259,551
Dec-06	231,394	$15,083,934	$148,046	$348	$15,232,328	$65.83	$56.81	$13,145,903	4	$ 95,260	$13,241,163	$1,991,165	$1,425,831	$3,416,996	$2,486,748	$ 3,420,748	-$3,752
Total	2,947,719	$198,663,407	$681,501	$58,707	$199,403,615	$67.65	$55.74	$164,312,765		$1,140,672	$165,453,437	$33,950,178	$17,109,969	$51,060,147	$29,840,974	$41,048,974	$10,011,173
Jan-07	266,910	$17,909,084	$50,985	$527	$17,960,595	$67.29	$59.39	$15,853,054	4	$ 98,311	$15,951,364	$2,009,231	$1,425,831	$3,435,062	$2,486,748	$ 3,420,748	$14,314
Feb-07	240,865	$20,535,038	$45,368	$0	$20,580,407	$85.44	$80.15	$19,304,685	4	$ 122,816	$19,427,501	$1,152,906	$1,425,831	$2,578,737	$2,486,748	$ 3,420,748	-$842,011
Mar-07	185,998	$14,002,873	$26,579	$177	$14,029,628	$75.43	$63.83	$11,871,904	4	$ 103,545	$11,975,449	$2,054,179	$1,425,831	$3,480,010	$2,486,748	$ 3,420,748	$59,262
Apr-07	261,897	$19,783,514	$32,250	$192	$19,815,955	$75.66	$64.84	$16,982,217	4	$ 104,744	$17,086,961	$2,728,994	$1,425,831	$4,154,825	$2,486,748	$ 3,420,748	$734,077
May-07	272,368	$19,248,808	$202,433	$4,303	$19,455,544	$71.43	$62.79	$17,101,410	4	$ 102,317	$17,203,727	$2,251,816	$1,425,831	$3,677,647	$2,486,748	$ 3,420,748	$256,899
Jun-07	199,567	$15,072,399	$75,327	$0	$15,147,727	$75.90	$60.54	$12,081,370	4	$ 99,660	$12,181,030	$2,966,697	$1,425,831	$4,392,528	$2,486,748	$ 3,420,748	$971,780
Jul-07	276,792	$19,268,701	$11,407	$0	$19,280,108	$69.66	$52.17	$14,439,882	4	$ 89,778	$14,529,659	$4,750,449	$1,425,831	$6,176,279	$2,486,748	$ 3,420,748	$2,755,532
Aug-07	324,886	$23,409,956	$7,816	$0	$23,417,772	$72.08	$53.57	$17,405,079	4	$ 91,436	$17,496,514	$5,921,258	$1,425,831	$7,347,089	$2,486,748	$ 3,420,748	$3,926,341
Sep-07	100,008	$6,676,514	$21,627	$0	$6,698,142	$66.98	$49.29	$4,929,042	4	$ 86,374	$5,015,416	$1,682,726	$1,425,831	$3,108,557	$2,486,748	$ 3,420,748	-$312,191
Total	2,129,292	$155,906,887	$473,793	$5,198	$156,385,878	$73.45	$61.04	$129,968,642		$898,981	$130,867,622	$25,518,256	$12,832,477	$38,350,733	$22,380,731	$30,786,731	$7,564,003

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Exhibit No. 2 to
Affidavit of Brian E. Forshaw
in Support of Complaint

COMPLAINT OF CONNECTICUT MUNICIPAL ELECTRIC ENERGY COOPERATIVE AND RICHARD BLUMENTHAL, ATTORNEY GENERAL FOR THE STATE OF CONNECTICUT, SEEKING IMMEDIATE TERMINATION OF RELIABILITY MUST RUN AGREEMENT AND REQUESTING FAST TRACK PROCESSING

Filed December 4, 2007

in

FERC Docket No. EL08-___-___

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ISO NEW ENGLAND
The people behind New England's power

2003
ANNUAL MARKETS REPORT

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Table 13 – ISO Model Market Price Measures, 2002 and 2003

Price Measure	2003 Price ($/MWh)	Quantity-Weighted Lerner Index	
		2002	2003
Competitive Benchmark Price	48.10		
Energy Clearing Price (Real-Time Hub Price as of March 1,2003; ECP prior to March 1, 2003)	52.91	11%	9%
Aggregate Bid-Intercept Price	46.03	6%	-4%

The model results suggest that the market continued to behave competitively through 2003. The QWLIs are somewhat lower than those estimated for 2002. This result could be due to a number of factors, including the introduction of SMD, the dispatch of PUSH units out-of-merit at their Economic Minimums to provide local reserves[37], and additional large gas-fired units placed into service during 2003 that created a larger number of hours during which minimum generation conditions prevailed.[38] These QWLIs indicate that the New England markets continue to be workably competitive.

Benchmark analysis will continue to play an important role in diagnosing the potential for the exercise of market power in the SMD environment. In its role as market monitor, the ISO intends to update this benchmark assessment over time to maintain its usefulness in providing timely diagnostic information.

12.5.4. Conclusion

The analyses conducted show that New England's wholesale power market has been workably competitive since the beginning of the markets and continued to be competitive in 2003. The continued competitiveness is consistent with the increase in generation capacity during 2003 and with the analysis of net revenues and market entry that follows in Section 12.6.

12.6. Net Revenues and Market Entry

Another market barometer compares market revenues with the revenue requirements for a new generating unit entering the market. In the long run, the revenues from the energy, capacity, and ancillary services markets must cover the costs of a new generating plant, including a competitive return on investment. Revenues consistently below this level would discourage entry into the market, eventually putting upward pressure on prices. On the other hand, revenues above this level should lead to new entrants and exert downward pressure on prices. The margin between a plant's market revenues and its variable costs (primarily fuel for fossil units) contributes to the recovery of its fixed costs, including non-variable operating and maintenance expenses and capital costs. This margin can be estimated, given the variable costs of a typical new generating unit, hourly energy-clearing prices in New England, and estimates of capacity and ancillary services revenue.

[37] Units dispatched at economic minimum are generally ineligible to set nodal LMPs, so the LMPs are lower than they would be if these units were part of the system-wide price-setting. See ISO New England Market Monitoring Department (2003) *A Review of Peaking Unit Safe Harbor (PUSH) Implementation and Results.*

[38] Bushnell, Mansur and Saravia (2004) find in a study of the California, PJM and New England markets that another explanation for the negative QWLIs is the presence of suppliers who are also large load aggregators who exercise monopsony power. While out-of-merit operation may be one driver of the New England outcome observed, the authors failed to reject the hypothesis that vertical integration of generation owners and retail suppliers who are overall "net buyers" also contributes to negative QWLIs in New England. This study covers the May 1999-September 2001 period; The Market Monitoring Department is investigating the extent to which this continues to be true. See Bushnell, Mansur and Saravia "Market Structure and Competition: A Cross-Market Analysis of U.S. Electricity Deregulation", UCEM Working Paper WP126. http://www.ucei.berkeley.edu/PDF/csemwp126.pdf (Accessed April 1, 2004).

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Figure 27 shows the net revenue from electric energy for a hypothetical generator bidding one (1) MW into the energy market at various price points. Net revenue was calculated using the ECP for hours in the Interim Markets period and the real-time Hub LMP for hours in the SMD period. It was assumed that the generator ran in every hour in which the electric energy price was equal to or greater than its bid. Net revenue was calculated by subtracting the bid from the electric energy price for each hour, and this value was summed over the year.[39] This calculation was performed for each bid point shown in the graph.

Figure 27

Net Revenue from Energy at Various Bid Points

Calendar Years 2000, 2001, 2002, 2003

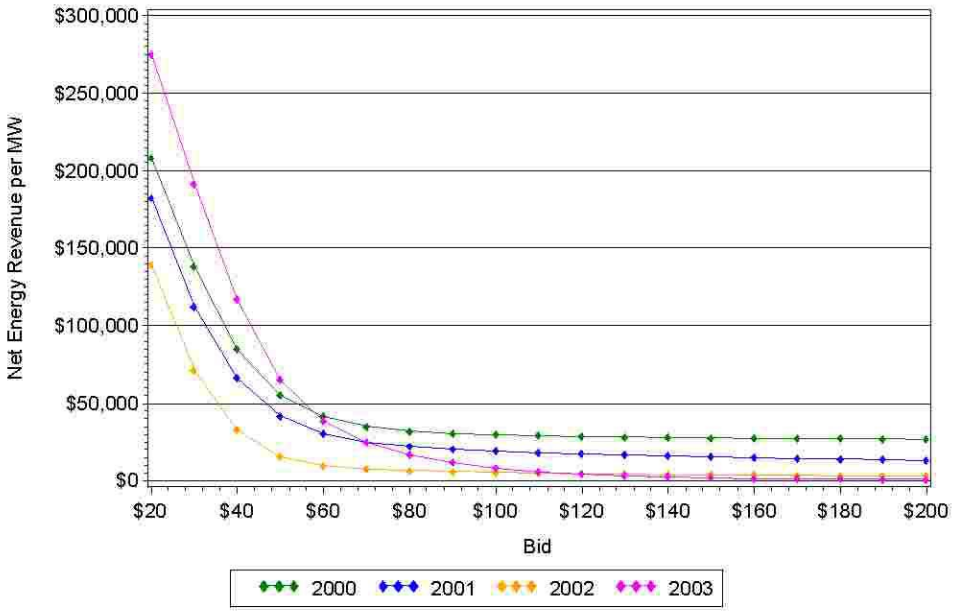

Figure 27 shows that a unit with variable costs of $40/MWh that ran whenever prices exceeded that level would have received approximately $120,000/MW in net revenue from New England's electric energy market in 2003. A New England generator with variable costs of $30/MWh (approximating a coal unit in New England) would have earned approximately $190,000/MW in net energy revenues in 2003. Note that it is only appropriate to calculate net revenues using this methodology for units or contracts with stable costs over time such as nuclear, hydro, and coal generators.

Table 14 presents an estimate of net revenues for hypothetical generators in New England during 2003. Daily marginal costs are calculated using spot fuel prices, the assumed heat rates, and other production costs, for each hour for a representative combined-cycle, natural gas-fired plant with a heat rate of 6,800 BTU/kWh and a typical gas-fired combustion-turbine unit with a heat rate of 10,500 BTU/kWh. It was assumed that the generator ran each hour that the price was above its marginal cost. Under these assumptions, the combined-cycle plant would have earned about $74,000/MW during 2003, while the combustion-turbine plant would have earned approximately $12,000/MW. For purposes of this analysis, unit outages and physical operating parameters are ignored.

The anticipated annual non-variable costs of a new combined-cycle plant in New England, which include fixed O&M, taxes, depreciation, debt repayment, and a competitive return on investment, are in the range of $100,000/MW to $125,000/MW. The corresponding values for a combustion-turbine plant are in the

[39] This assumes that the generator is a price-taker, bidding its marginal cost.

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range of $60,000/MW to $80,000/MW.[40] These calculations, therefore, suggest that neither of the plants burning natural gas at the delivered spot price in 2003 would have recovered its annual fixed costs plus a return on investment from energy market revenues alone. In fact, the net revenue curve tends to overestimate the contribution toward generators' fixed costs and investment return since it ignores plant outages and other operational constraints that may prevent a plant from running in every profitable hour. On the other hand, this calculation underestimates revenues by excluding revenue sources such as ancillary services and capacity payments. Though ancillary market opportunities in 2003 were modest, capacity payments are estimated to be in the range of $2,000/MW, while ancillary service revenues are negligible. Table 14 summarizes these findings.

Long-run equilibrium analysis is not applicable to a single year in isolation since market outcomes will vary over time. Nevertheless, it appears that at 2003 electric energy prices and fuel costs, the hypothetical generators' net revenues were lower than the amount needed to cover a new entrant's fixed costs and competitive rate of return on investment. This observation is consistent with relatively robust reserve margins, the lack of announcements of new projects, few units in the early stages of construction, and the cancellation of some new generation projects.

Table 14 - Net Revenue for Hypothetical Generators

Generator	Marginal Cost	Heat Rate	2003 net revenue ($/MW-Year)	Annual Non-Variable Costs – New Unit
Generator X	$30/MWh		$190,000	
Generator Y	$40/MWh		$120,000	
Representative CC/Gas fired	Daily fuel cost times heat rate	6,800 Btu/KWh	$ 74,000	$100,000 – 125,000/MWh
Representative CT/Gas fired	Daily fuel cost times heat rate	10,500 Btu/KWh	$ 12,000	$60,000 – 80,000/MWh
Approximate revenue from capacity sales	$2,000 /MW			
Approx. ancillary services revenue	$0/MW			

In recent studies of the New England electricity markets, Dr. Paul Joskow of MIT also used a form of net revenue benchmark analysis to demonstrate that the energy markets do not provide sufficient scarcity rents to recover the annualized fixed costs (defined as amortized capital costs + fixed O&M) of a unit operating only during periods of scarcity. He concludes that, without enhancements, the existing New England electric energy and reserves markets are unlikely to provide the necessary incentives for investment in new generating capacity to maintain existing reliability levels. Although raising the offer cap could encourage this level of investment, Dr. Joskow cautions that this may simply increase incentives for the exercise of market power. Rather, he states, the proper policy is to develop market rules that facilitate prices rising to the existing offer cap during reserve-deficiency hours.[41]

[40] These estimates are intended to be the relevant annual returns required for an entity contemplating new generation investment.

[41] "*The Difficult Transition To Competitive Electricity Markets In The U.S.*", Joskow, Paul L., Ph.D., Prepared for the conference "Electricity Deregulation: Where From Here?" at the Bush Presidential Conference Center. Texas A&M University, April 4, 2003. http://econ-www.mit.edu/faculty/download_pdf.php?id=537 (Accessed June 2, 2004).

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ISO new england

2004

Annual Markets Report

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2004 Annual Markets Report

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4.2.7 Net Revenues and Market Entry

Another market barometer compares market revenues with the revenue requirements for a new generating unit seeking to enter the market. In the long run, the revenues from the energy and capacity markets and the Ancillary Services Markets must be expected to cover the costs of a proposed new generating plant, including a competitive return on investment. Revenues consistently below this level would discourage entry into the market, eventually putting upward pressure on prices. On the other hand, revenues above this level should lead to new entrants and exert downward pressure on prices. The margin between a plant's market revenues and its variable costs (primarily fuel for fossil units) contributes to the recovery of its fixed costs, including nonvariable operating and maintenance expenses and capital costs. This margin can be estimated, given the variable costs of a typical new generating unit, hourly energy-clearing prices in New England, and estimates of capacity and ancillary services revenue.

Figure 54 shows the net revenue from electric energy for hypothetical generators offering one megawatt into the energy market each hour of the year at various price points. Net revenue was calculated using the energy-clearing price, for hours in the Interim Markets period, and the real-time Hub LMP, for hours in the SMD period. It was assumed that the generator ran in every hour in which the electric energy price was equal to or greater than its offer. Net revenue was calculated by subtracting the offer from the electric energy price for each hour, and this value was summed over the year.[54] This calculation was performed for each offer point shown in the graph. Note that it is appropriate to use this methodology to calculate net revenues only for units or contracts with stable costs over time, such as nuclear, hydro, and coal generators.

Figure 54 shows that a unit with variable costs of $40/MWh that ran whenever energy prices exceeded that level would have received approximately $121,000/MW-Year in net revenue from New England's electric energy market in 2004. A New England generator with variable costs of $30/MWh (approximating a coal unit in New England) would have earned approximately $199,000/MW-Year in net-energy revenues in 2004. The net revenue for low price levels has been highest in the last two years, reflecting increased electricity prices driven primarily by high fuel costs. At high price levels, net revenues have been low for the past three years, due to relatively few high-priced hours compared to previous years.

[54] This assumes that the generator is a price taker, offering at its marginal cost.

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Figure 54

Net Revenue from Energy per MW at Various Offer Points
Calendar Years 2000, 2001, 2002, 2003, and 2004

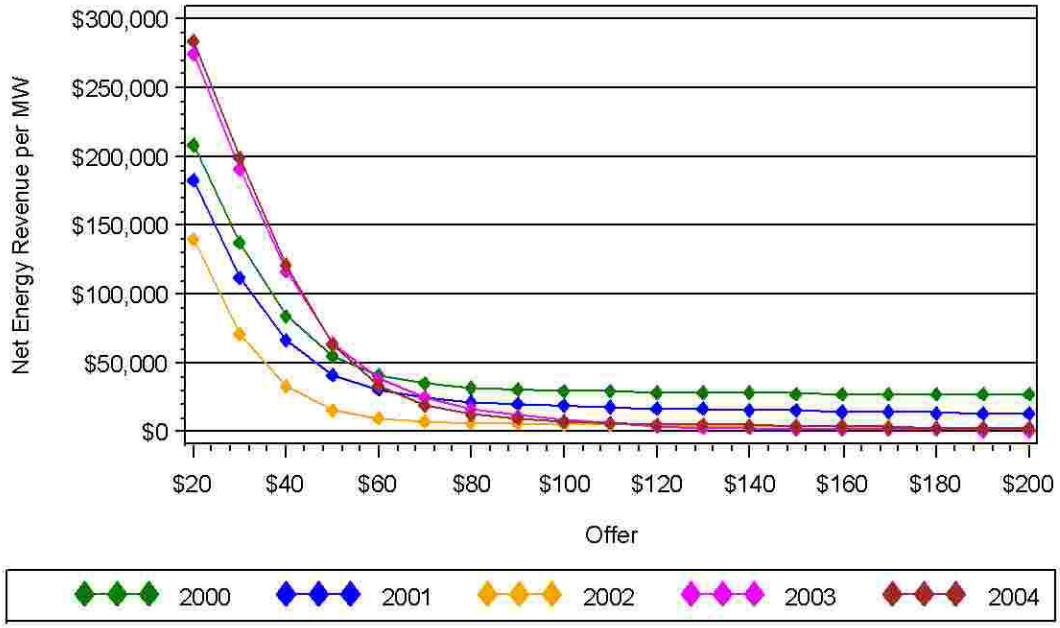

Table 40 presents an estimate of net revenues for two hypothetical gas-fired generators in New England during 2004. Gas-fired generators are modeled because they represent the typical new unit brought online in New England. Daily marginal costs are calculated for each hour using spot-fuel prices, the assumed heat rates, and other production costs, for both a representative combined-cycle natural gas-fired plant with a heat rate of 7,000 BTU/kWh and a typical gas-fired combustion-turbine unit with a heat rate of 10,500 BTU/kWh. It was assumed that the generator ran each hour that the price was above its marginal cost. These calculations are a more accurate representation of net revenues for gas plants than can be determined from Figure 54, as gas prices vary substantially throughout the year. However, by ignoring start-up costs and generator inflexibility, particularly for combined-cycle units, the calculations overstate net revenues.

Under these assumptions, the combined-cycle plant would have earned about $63,000/MW in the energy market during 2004, while the combustion-turbine plant would have earned approximately $8,000/MW. If the combustion-turbine plant participated in the Forward Reserve Market, it could have earned another $44,500/MW. Capacity-market revenues were negligible for the year. For purposes of this analysis, unit outages were represented by reducing energy revenues by 5%.

The anticipated annual nonvariable costs of a new combined-cycle plant in New England, which include fixed O&M, taxes, depreciation, debt repayment, and a competitive return on investment, are in the range of $100,000/MW to $125,000/MW. The corresponding values for a combustion-

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turbine plant are in the range of $60,000/MW to $80,000/MW.[55] These calculations suggest that neither of the hypothetical plants burning natural gas at the delivered spot price in 2004 would have recovered its annual fixed costs plus a return on investment. Combined-cycle revenues were about one-half of what is needed, while combustion-turbine revenues were 70% to 80% of requirements. These results are similar to those of the last few years. In fact, the net revenue curve tends to overestimate the contribution toward generators' fixed costs and investment return since it ignores operational constraints that may prevent a plant from running in every profitable hour.

While this analysis is performed using LMPs at the Hub, differences in energy-market prices among sub-areas were modest and likely would have only a moderate effect on these results. In addition, it is likely that new entry costs are higher in some sub-areas such as Southwest Connecticut and Boston. Capacity and reserve revenues are the same throughout the system. The results correspond to the requests for Reliability Agreements (see Section 3.4) and the lack of new entry in constrained sub-areas. That is, a lack of location-specific capacity signals fails to indicate the need for additional capacity or transmission infrastructure in constrained areas. The ISO is working to gain approval and to implement locational capacity and reserve markets that should reduce the need for Reliability Agreements.

Long-run equilibrium analysis is not applicable to a single year in isolation since market outcomes vary over time. Nevertheless, it appears that at 2004 electric energy prices and fuel costs, the hypothetical generators' net revenues were lower than the amount needed to cover a new entrant's fixed costs and competitive rate of return on investment. This observation is indicative of relatively robust reserve margins, the lack of announcements of new projects, few units in the early stages of construction, and the cancellation of some new generation projects.

[55] These estimates are intended to be the relevant annual returns required for an entity contemplating an investment in new generation.

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Table 40 - Yearly Total Net Revenue per MW for Hypothetical Generators

Generator	Marginal Cost Formula	Heat Rate (Btu/KWh)	($/MW-Year)			
			2004 Net Energy Revenue	Approximate Revenue From Capacity Sales*	Approximate Ancillary Services Revenue#	Approximate Total Revenue
Representative Combined-Cycle/ Gas-fired	(Daily fuel cost x heat rate) + (VOM‡ of $1/MWh)	7,000	$63,000	$360	$1,350	$64,710
Representative Combustion-Turbine/ Gas-fired	(Daily fuel cost x heat rate) + (VOM of $3/MWh)	10,500	$8,000	$360	$44,500	$52,860

*Capacity sales revenue is based on ISO ICAP supply auction clearing prices.

#Ancillary services revenue is based on the Regulation Market for combined-cycle, and the Regulation and Forward Reserves Markets for combustion-turbine. Forward Reserve revenues equal auction revenues minus average penalties.

‡Variable operations and maintenance costs.

4.2.8 Summary of Analyses

Overall, the concentration of generation ownership in New England's wholesale markets continued at low levels during 2004. Certain areas of the system, such as NEMA/Boston and Vermont, defined by transmission interfaces, continue to have high concentrations of unit ownership. Overall, generation portfolio sizes decreased during the year as asset ownership changed. While this is generally favorable, there remain areas of the system where the lack of diversity in unit ownership necessitates continued oversight and targeted mitigation rules.

Large increases in available generating capacity over the last five years have resulted in few hours during which suppliers were pivotal. However, unexpectedly high load levels or unit outages still can create pivotal suppliers, especially during high-maintenance periods in the spring and fall. Over time, growing electricity demand plus reserves reduce the current surplus, the instances of pivotal suppliers may increase; continued vigilance is needed.

The current surplus, coupled with the general lack of high-peak loads, helped to keep prices at competitive levels during 2004, as determined by the benchmark analysis. The net-revenue analysis indicates that the hypothetical profit margin for spot-market-only generators appeared to be below what would be predicted to be the requirements for new entry.

The ISO is working to enhance locational price signals. FERC's settlement process for locational capacity markets, in which the ISO is participating, will result in a market design that provides better investment signals in all areas. A locational reserve requirement reflected in the market rules also would better value new demand and supply options in constrained areas. That, in turn,

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ISO new england

2005 Annual Markets Report

ISO New England Inc.
June 1, 2006

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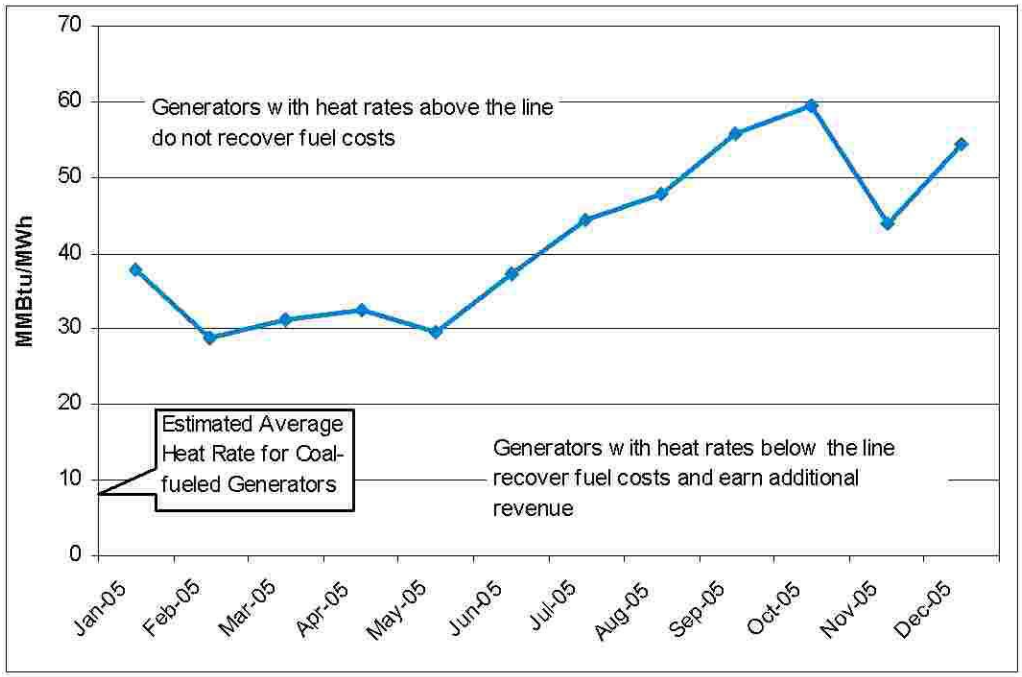

Figure 5-8: Monthly average implied heat rates in New England, coal and electricity.

Note: Daily implied heat rates were calculated as the ratio of the average day-ahead on-peak LMP for all nodes with generators of each fuel type and the fuel price. For each month, an average of all days in the month was calculated.

5.2.7 Net Revenues and Market Entry

Another market barometer compares market revenues with the revenue requirements for a new generating unit seeking to enter the market. In the long run, the revenues from the energy, capacity, and ancillary services markets must be expected to cover the costs of a proposed new generating plant, including a competitive return on investment. Revenues consistently below this level would discourage entry into the market, eventually putting upward pressure on prices. On the other hand, revenues above this level should lead to new entrants and exert downward pressure on prices. The margin between a plant's market revenues and its variable costs (primarily fuel for fossil units) contributes to the recovery of its fixed costs, including nonvariable operating and maintenance expenses and capital costs. This margin can be estimated, given the variable costs of a typical new generating unit, hourly energy-clearing prices in New England, and revenue estimates for capacity and ancillary services.

Table 5-5 presents an estimate of the theoretical maximum net revenues for two hypothetical gas-fired generators in New England during 2005. This estimate is a metric developed by FERC for comparison across power pools. It represents an upper bound of revenue and is not informative about actual financial conditions for many generators in New England. Gas-fired generators were modeled because they represent the typical new unit that has been brought on line in New England. Daily marginal costs were calculated for each hour using spot-fuel prices, the assumed heat rates, and other production costs for both an efficient combined-cycle natural gas-fired plant with a heat rate of 7,000 Btu/kWh and a typical gas-fired combustion-turbine unit with a heat rate of 10,500 Btu/kWh. It was assumed that the generator ran each hour the price was above its marginal cost, ignoring commitment costs, ramping constraints, and start-up and minimum run times. However, by ignoring

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start-up costs and generator inflexibility, particularly for combined-cycle units, the calculations overstate actual net revenues.

Table 5-5
2005 Yearly Theoretical Maximum Revenue, Net of Variable Costs, per MW, for Hypothetical Generators

Generator	Marginal Cost Formula	Heat Rate (Btu/kWh)	($/MW-Year)			
			2005 Net Energy Revenue	Approximate Revenue from Capacity Sales[a]	Approximate Ancillary Services Revenue[b]	Approximate Theoretical Max. Revenue
Representative combined-cycle/ gas-fired	(Daily fuel cost x heat rate) + (VOM[c] of $1/MWh)	7,000	$111,635	$200	$2,208	$114,043
Representative combustion-turbine/ gas-fired	(Daily fuel cost x heat rate) + (VOM of $3/MWh)	10,500	$20,877	$200	$32,225	$53,302

[a] The revenue from capacity sales is based on ICAP supply auction-clearing prices.
[b] The revenue from ancillary services is based on the Regulation Market for combined-cycle units, and the Regulation and Forward Reserve Markets for combustion-turbine units. Forward-reserve revenues equal auction revenues minus average penalties.
[c] Variable operations and maintenance costs.

Under these assumptions, the combined-cycle plant would have earned a theoretical maximum of about $114,000/MW in the electric-energy markets and Ancillary Services Markets during 2005, net of variable costs. The combustion-turbine plant would have earned a theoretical maximum of approximately $21,000/MW in the electric-energy market, and if it participated in the Forward Reserve Market, it could have earned an additional $30,000/MW. Capacity-market revenues were negligible for the year. For this analysis, unit outages were represented by reducing energy revenues by 5%.

This analysis was performed using LMPs at the Hub, although LMPs in some zones were higher or lower than those at the Hub. In addition, new entry costs would have likely been higher in some subareas, such as Southwest Connecticut and Boston. Capacity and reserve revenues were the same throughout the system.

In addition to fuel and other variable costs accounted for in the net-revenue analysis, in the long run new entrants must on average earn enough to cover their nonvariable costs, which include fixed O&M costs, taxes, depreciation, debt repayment, and a competitive return on investment.

The above analysis is hypothetical. The ISO also conducted an analysis of revenues and costs of real generators. This analysis included eight relatively efficient natural-gas-fired combined-cycle generators throughout New England. The analysis included revenues based on each generator's

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megawatts cleared in the Day-Ahead and Real-Time Energy Markets and the corresponding LMPs at each generator's node. Revenues from daily reliability payments and the Regulation Market were also included.[120] The analysis did not account for revenues from bilateral contracts.

Costs were calculated based on each unit's generation and marginal cost per megawatt-hour, including VOM, fuel costs, fuel-transport adders, and emission costs. Start-up and no-load costs, based on generators' offers, were also included. However, because some participants waive start-up and no-load costs, these were zero for some of the generators included in this analysis.

While specific costs and revenues are confidential and cannot be reported here, the analysis showed that, accounting for variable costs, estimated net revenues were significantly lower than indicated by Table 5-5. Net revenues ranged from $15,000/MW-Year to $80,000/MW-Year, and averaged $47,000/MW-Year. Net revenues were lower for generators in the Maine and New Hampshire load zones, where LMPs are lower than those at the Hub; they were highest for generators in the Connecticut and NEMA load zones, where LMPs are higher.

Revenues net of variable costs contribute to covering fixed costs. Several of the generators included in this analysis have Reliability Agreements, which provide monthly fixed-cost payments. These payments were not included in the revenue analysis. The analysis shows that net market revenues for these generators were inadequate to cover their fixed costs, which is consistent with the determination that the generators required additional, out-of-market payments.

5.2.8 Analysis of Participant Credit Ratings

Due to the capital-intensive nature of the electricity industry, the creditworthiness of firms participating in a market can have an impact on operations and infrastructure development. This section evaluates changes in the credit ratings of the 10 largest participants, measured in terms of generating capacity ownership. Together, these 10 participants own approximately 73% of generation capacity in New England. Table 5-6 shows the distribution of credit rating scores Standard and Poor's has assigned these 10 firms for 2000 to 2005.[121] Relative to the year 2000, credit ratings have degraded slightly; however, over the past three years, the number of firms in each category has remained constant.

[120] Daily reliability payments include first- and second-contingency NCPC payments, and voltage and distribution payments (see Section 4.2).

[121] Standard and Poor's credit rating scores are available for registered members at http://www2.standardandpoors.com.

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2006 Annual Markets Report

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June 11, 2007

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5.2.7 Net Revenues and Market Entry

Another market barometer compares market revenues with the revenue requirements for a new generating unit seeking to enter the market. In the long run, the revenues from the energy, capacity, regulation, and reserve markets must be expected to cover the costs of a proposed new generating plant, including a competitive return on investment. Revenues consistently below this level would discourage entry into the market, eventually putting upward pressure on prices. On the other hand, revenues above this level should lead to new entrants and exert downward pressure on prices. The margin between a plant's market revenues and its variable costs (primarily fuel for fossil units) contributes to the recovery of its fixed costs, including nonvariable operating and maintenance expenses and capital costs. This margin can be estimated, given the variable costs of a typical new generating unit, hourly energy-clearing prices in New England, and revenue estimates for capacity and ancillary services.

Table 5-5 presents an estimate of the theoretical maximum net revenues for two hypothetical gas-fired generators in New England during 2006. This estimate is a metric developed by FERC for comparison across power pools. It represents an upper bound of revenue and is not informative about actual financial conditions for many generators in New England. Gas-fired generators were modeled because they represent the typical new unit that has been brought on line in New England. Daily marginal costs were calculated for each hour using spot-fuel prices, the assumed heat rates, and other production costs for both an efficient combined-cycle natural-gas-fired plant with a heat rate of 7,000 Btu/kWh and a typical gas-fired combustion-turbine unit with a heat rate of 10,500 Btu/kWh. It was assumed that the generator ran each hour the price was above its marginal cost, ignoring commitment costs, ramping constraints, and start-up and minimum run times. However, by ignoring start-up costs and generator inflexibility, particularly for combined-cycle units, the calculations overstate actual net revenues.

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Table 5-5
Yearly Theoretical Maximum Revenue for Hypothetical Generators
Net of Variable Costs per MW, 2006

Generator	Marginal Cost Formula	Heat Rate (Btu/kWh)	($/MW-Year)			
			2006 Net Energy Revenue	Approximate Revenue from Capacity Sales[a]	Approximate Ancillary Services Revenue[b]	Approximate Theoretical Max. Revenue
Representative combined cycle/ gas fired	(Daily fuel cost x heat rate) + (VOM[c] of $1/MWh)	7,000	$100,969	$479	$2,600	$104,048
Representative combustion turbine/ gas fired	(Daily fuel cost x heat rate) + (VOM[c] of $3/MWh)	10,500	$24,422	$479	$22,667	$47,568

(a) The revenue from capacity sales is a weighted average of ICAP supply and deficiency auction clearing prices, adjusted for forced-outage rate.

(b) The revenue from ancillary services is based on the Regulation Market for combined-cycle units and the Forward Reserve Market for combustion-turbine units. Forward-reserve revenues equal auction revenues minus performance penalties.

(c) Variable operations and maintenance costs.

Under these assumptions, the combined-cycle plant would have earned a theoretical maximum of about $104,000/MW in the electric energy, capacity, regulation, and reserve markets during 2006, net of variable costs. The combustion-turbine plant would have earned a theoretical maximum of approximately $24,000/MW in the electric energy market. If it participated in the Forward Reserve Market, it could have earned an additional $22,000/MW. Capacity market revenues were negligible for the year. For this analysis, unit outages were represented by reducing energy revenues by 5%.

The net revenue of the representative combined-cycle generator in 2006 decreased 8% from the 2005 estimate. For the representative combustion turbine, the estimated net revenue decreased almost 11% between 2005 and 2006. For both years, the analysis was performed using LMPs at the Hub, although LMPs in some zones were higher or lower than those at the Hub. In addition, new entry costs would have likely been higher in some subareas, such as Southwest Connecticut and Boston. Capacity revenues were the same throughout the system. FRM revenues for the Rest-of-System zone were used for the post-ASM II period.

In addition to fuel and other variable costs accounted for in the net-revenue analysis, in the long run, new entrants must on average earn enough to cover their nonvariable costs, which include fixed O&M costs, taxes, depreciation, debt repayment, and a competitive return on investment.

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FURTHER AFFIANT SAYETH NOT.

Dated at Norwich, Conn. this 29th day of November, 2007.

Brian Forshaw

Brian E. Forshaw

Subscribed and sworn to before
me this 29th day of November, 2007

Ellen F Kachmar

Notary Public

My Commission expires:

Ellen F. Kachmar
Notary Public-Connecticut
My Commission Expires
April 30, 2012

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Connecticut Municipal Electric
Energy Cooperative
Richard Blumenthal, Attorney General
for the State of Connecticut
Complainants,

v. Docket No. EL08-____

Milford Power Company, LLC
ISO New England Inc.,
Respondent.

NOTICE OF COMPLAINT

([DATE])

Take notice that on December 4, 2007, Connecticut Municipal Electric Energy Cooperative and Richard Blumenthal, Attorney General for the State of Connecticut (collectively, CMEEC/CTAG) filed a formal complaint against Milford Power Company, LLC (Milford) and ISO New England Inc. (ISO) pursuant to section 206 of the Federal Power Act, 16 U.S.C. §§ 824(e), 825(e), and Rule 206 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission, 18 CFR 385.206, alleging that Milford was no longer eligible to receive a Reliability Must Run ("RMR") agreement, and that the RMR agreement between Milford and the ISO should be terminated immediately. CMEEC/CTAG seek consideration of the Complaint in accordance with the Commission's "Fast Track" procedures.

CMEEC/CTAG certify that copies of the complaint were served on the contacts for Milford and ISO, as well as on persons designated on the official service list in *Milford Power Company, LLC*, Docket No. ER05-163-000.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211, 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. The Respondents' answer and all interventions, or protests must be filed on or before the comment date. The Respondents' answer, motions to intervene, and protests must be served on the Complainants.

The Commission encourages electronic submission of protests and interventions in

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lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on [DATE]

Kimberly D. Bose,
Secretary.

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CERTIFICATE OF SERVICE

In accordance with Commission Rule 206(c), 18 C.F.R. § 385.206(c), I hereby certify that I have on this 4th day of December, 2007, caused the foregoing complaint to be served electronically upon the following:

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In addition, we have served the foregoing complaint by electronic mail or first class mail to all parties on the list compiled by the Secretary of the Commission in *Milford Power Company, LLC*, Docket No. ER05-163.

/s/ Scott H. Strauss
Scott H. Strauss

Law Offices of:
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1333 New Hampshire Avenue, NW
Washington, DC 20036
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